

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 86-[AMENDED]

1. The authority citation for part 86 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart A-[Amended]

2. Section 86.007-23 is amended by adding paragraph (n) to read as follows:

§86.007-23 Required data.

* * * * *

(n) Measure CO₂, N₂O, and CH₄ with each low-hour certification test for heavy-duty engines using the procedures specified in 40 CFR part 1065 as specified in this paragraph (n). Report these values in your application for certification. The requirements of this paragraph (n) apply starting with model year 2011 for CO₂ and 2012 for CH₄. The requirements of this paragraph (n) related to N₂O emissions apply for engine families that depend on NO_x aftertreatment to meet emission standards starting with model year 2013. These measurements are not required for NTE testing. Use the same units and calculations as for your other results to report a single

weighted value for CO₂, N₂O, and CH₄ for each test. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/kW-hr.
- (2) Round N₂O to the nearest 0.001 g/kW-hr.
- (3) Round CH₄ to the nearest 0.001g/kW-hr.

3. Section 86.078-3 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§86.078-3 Abbreviations.

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*      *      *      *      *
*      *      *      *      *      *      *
CH4 methane.

*      *      *      *      *      *      *
N2O nitrous oxide.

*      *      *      *      *      *      *

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Subpart E-[Amended]

4. Section 86.403-78 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§86.403-78 Abbreviations.

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*      *      *      *      *
*      *      *      *      *      *      *
CH4 methane.

*      *      *      *      *      *      *
N2O nitrous oxide.

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5. Section 86.431-78 is amended by adding paragraph (e) to read as follows:

§86.431-78 Data submission.

* * * * *

(e) Measure CO₂, N₂O, and CH₄ as described in this paragraph (e) with each zero kilometer certification test (if one is conducted) and with each test conducted at the applicable minimum test distance as defined in §86.427-78. Use the analytical equipment and procedures specified in 40 CFR part 1065 as needed to measure N₂O, and CH₄. Report these values in your application for certification. The requirements of this paragraph (e) apply starting with model year 2011 for CO₂ and 2012 for CH₄. The requirements of this paragraph (e) related to N₂O emissions apply for engine families that depend on NO_x aftertreatment to meet emission standards starting with model year 2013. Small-volume manufacturers (as defined in §86.410-2006(e)) may omit measurement of N₂O and CH₄; other manufacturers may provide appropriate data and/or information and omit measurement of N₂O and CH₄ as described in 40 CFR 1065.5. Use the same measurement methods as for your other results to report a single value for CO₂, N₂O, and CH₄. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/km.
- (2) Round N₂O to the nearest 0.001 g/km.
- (3) Round CH₄ to the nearest 0.001g/km.

PART 87-[AMENDED]

6. The authority citation for part 87 is revised to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart A-[Amended]

7. Section 87.2 is amended by adding the abbreviation CO₂ in alphanumeric order to read as follows:

§87.2 Acronyms and abbreviations.

* * * * *

CO₂ carbon dioxide.

* * * * *

8. Section 87.64 is revised to read as follows:

§87.64 Sampling and analytical procedures for measuring gaseous exhaust emissions.

(a) The system and procedures for sampling and measurement of gaseous emissions shall be as specified by Appendices 3 and 5 to ICAO Annex 16 (incorporated by reference in §87.8).

(b) Starting January 1, 2011, report CO₂ values along with your emission levels of regulated NO_x to the Administrator for engines of a type or model of which the

date of manufacture of the first individual production model was on or after January 1, 2011. By January 1, 2011, report CO₂ values along with your emission levels of regulated NO_x to the Administrator for engines currently in production and of a type or model for which the date of manufacture of the individual engine was before January 1, 2011. Round CO₂ to the nearest 1 g/kiloneutron r0.

(c) Report CO₂ by calculation from fuel mass flow rate measurements in Appendices 3 and 5 to ICAO Annex 16, volume II or alternatively, according to the measurement criteria of CO₂ in Appendices 3 and 5 to ICAO Annex 16, volume II.

PART 89-[AMENDED]

9. The authority citation for part 89 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart B-[Amended]

10. Section 89.115 is amended by revising paragraph (d) (9) to read as follows:

§89.115 Application for certificate.

* * * * *

(d) * * *

(9) All test data obtained by the manufacturer on each test engine, including CO₂ as specified in §89.407(d) (1);

* * * * *

Subpart E—[Amended]

11. Section 89.407 is amended by revising paragraph (d) (1) to read as follows:

§89.407 Engine dynamometer test run.

* * * * *

(d) * * *

(1) Measure HC, CO, CO₂, and NO_x concentrations in the exhaust sample. Use the same units and modal calculations as for your other results to report a single weighted value for CO₂; round CO₂ to the nearest 1 g/kW-hr.

* * * * *

PART 90—[AMENDED]

12. The authority citation for part 90 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart B—[Amended]

13. Section 90.107 is amended by revising paragraph (d) (8) to read as follows:

§90.107 Application for certification.

* * * * *

(d) * * *

(8) All test data obtained by the manufacturer on each test engine, including CO₂ as specified in §90.409 (c) (1);

* * * * *

Subpart E-[Amended]

14. Section 90.409 is amended by revising paragraph (c) (1) to read as follows:

§90.409 Engine dynamometer test run.

* * * * *

(c) * * *

(1) Measure HC, CO, CO₂, and NOx concentrations in the exhaust sample. Use the same units and modal calculations as for your other results to report a single weighted value for CO₂; round CO₂ to the nearest 1 g/kW-hr.

* * * * *

PART 94-[AMENDED]

15. The authority citation for part 94 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart A-[Amended]

16. Section 94.3 is amended by adding the abbreviation CH₄ in alphanumeric order to read as follows:

§94.3 Abbreviations.

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* * * * *

CH₄ methane.

* * * * *

Subpart B-[Amended]

17. Section 94.103 is amended by adding paragraph (c) to read as follows:

§94.103 Test procedures for Category 1 marine engines.

* * * * *

(c) Measure CH₄ as specified in 40 CFR 1042.235 starting in the 2012 model year.

18. Section 94.104 is amended by adding paragraph (e) to read as follows:

§94.104 Test procedures for Category 2 marine engines.

* * * * *

(e) Measure CO₂ as described in 40 CFR 92.129 through the 2010 model year. Measure CO₂ as specified in 40 CFR 1042.235 starting in the 2011 model year. Measure CH₄ as specified in 40 CFR 1042.235 starting in the 2012 model year.

Subpart C—[Amended]

19. Section 94.203 is amended by revising paragraph (d) (10) to read as follows:

§94.203 Application for certification.

* * * * *

(d) * * *

(10) All test data obtained by the manufacturer on each test engine, including CO₂ and CH₄ as specified in 40 CFR 89.407(d) (1) and §94.103(c) for Category 1 engines, §94.104(e) for Category 2 engines, and §94.109(d) for

Category 3 engines. Small-volume manufacturers may omit measurement and reporting of CH₄.

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20. Add part 98 to read as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

Sec.

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- 98.428 Definitions.

Authority: 42 U.S.C. 7401, et seq.

Subpart A—General Provisions

§98.1 Purpose and Scope.

(a) This part establishes mandatory greenhouse gas (GHG) reporting requirements for owners and operators of certain facilities that directly emit GHG as well as for certain fossil fuel suppliers and industrial GHG suppliers. For suppliers, the GHGs reported are the quantity that would be emitted from combustion or use of the products supplied.

(b) Owners and operators of facilities and suppliers that are subject to this part must follow the requirements of subpart A and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the subparts B through PP of this part shall take precedence.

§98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a)(1) in any calendar year

starting in 2010. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part.

(i) Electricity generation (units that report CO₂ emissions year-round through 40 CFR part 75).

(ii) Adipic acid production.

(iii) Aluminum production.

(iv) Ammonia manufacturing.

(v) Cement production.

(vi) HCFC-22 production.

(vii) HFC-23 destruction processes that are not collocated with a HCFC-22 production facility and that destroy more than 2.14 metric tons of HFC-23 per year.

(viii) Lime manufacturing.

(ix) Nitric acid production.

(x) Petrochemical production.

(xi) Petroleum refineries.

(xii) Phosphoric acid production.

(xiii) Silicon carbide production.

(xiv) Soda ash production.

(xv) Titanium dioxide production.

(xvi) Municipal solid waste landfills that generate CH₄ in amounts equivalent to 25,000 metric tons CO₂e or more

per year, as determined according to subpart HH of this part.

(xvii) Manure management systems with combined CH₄ and N₂O emissions in amounts equivalent to 25,000 metric tons CO₂e or more per year, as determined according to subpart JJ of this part.

(2) A facility that contains any source category (as defined in subparts C through JJ of this part) that is listed in this paragraph (a) (2) in any calendar year starting in 2010 and that emits 25,000 metric tons CO₂e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all source categories that are listed in this paragraph. For these facilities, the annual GHG report must cover all source categories and GHGs for which calculation methodologies are provided in subparts C through JJ of this part.

- (i) Ferroalloy Production.
- (ii) Glass Production.
- (iii) Hydrogen Production.
- (iv) Iron and Steel Production.
- (v) Lead Production.
- (vi) Pulp and Paper Manufacturing.
- (vii) Zinc Production.

(3) A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3). For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.

(i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.

(ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater.

(iii) The facility emits 25,000 metric tons CO₂e or more per year in combined emissions from all stationary fuel combustion sources.

(4) A supplier (as defined in subparts KK through PP of this part) that provides products listed in this paragraph (a)(4) in any calendar year starting in 2010. For these suppliers, the annual GHG report must cover all applicable products for which calculation methodologies are provided in subparts KK through PP of this part.

(i) Coal-to-liquids suppliers, as specified in this paragraph (i).

(A) All producers of coal-to-liquid products.

(B) Importers of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO₂e or more.

(C) Exporters of an annual quantity of coal-to-liquid products is equivalent to 25,000 metric tons CO₂e or more.

(ii) Petroleum product suppliers, as specified in this paragraph (ii):

(A) All petroleum refineries that distill crude oil.

(B) Importers of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO₂e or more.

(C) Exporters of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO₂e or more.

(iii) Natural gas and natural gas liquids suppliers, as specified in this paragraph (iii):

(A) All natural gas fractionators.

(B) All local natural gas distribution companies.

(iv) Industrial greenhouse gas suppliers, as specified in this paragraph (iv):

(A) All producers of industrial greenhouse gases.

(B) Importers of industrial greenhouse gases with annual bulk imports of N₂O, fluorinated GHG, and CO₂ that in

combination are equivalent to 25,000 metric tons CO₂e or more.

(C) Exporters of industrial greenhouse gases with annual bulk exports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.

(v) Carbon dioxide suppliers, as specified in this paragraph (v).

(A) All producers of CO₂.

(B) Importers of CO₂ with annual bulk imports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.

(C) Exporters of CO₂ with annual bulk exports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.

(5) Research and development activities are not considered to be part of any source category defined in this part.

(b) To calculate GHG emissions for comparison to the 25,000 metric ton CO₂e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual CO₂e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Calculate the annual emissions of CO₂, CH₄, N₂O, and each fluorinated GHG in metric tons from all applicable source categories listed in paragraph (a)(2) of this section. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed in Table A-1 of this subpart.

(2) For each general stationary fuel combustion unit, calculate the annual CO₂ emissions in metric tons using any of the four calculation methodologies specified in §98.33(a). Calculate the annual CH₄ and N₂O emissions from the stationary fuel combustion sources in metric tons using the appropriate equation in §98.33(c). Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH₄ and N₂O from biomass combustion.

(3) For miscellaneous uses of carbonate, calculate the annual CO₂ emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (b)(2), and (b)(3) of this section for each GHG and calculate metric tons of CO₂e using Equation A-1 of this section.

$$\text{CO}_2\text{e} = \sum_{i=1}^n \text{GHG}_i \times \text{GWP}_i \quad (\text{Eq. A-1})$$

Where:

CO₂e = Carbon dioxide equivalent, metric tons/year.
 GHG_i = Mass emissions of each greenhouse gas listed in Table A-1 of this subpart, metric tons/year.
 GWP_i = Global warming potential for each greenhouse gas from Table A-1 of this subpart.
 n = The number of greenhouse gases emitted.

(5) For purpose of determining if an emission threshold has been exceeded, include in the emissions calculation any CO₂ that is captured for transfer off site.

(c) To calculate GHG emissions for comparison to the 25,000 metric ton CO₂e/year emission threshold for stationary fuel combustion under paragraph (a) (3) of this section, calculate CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit by following the methods specified in paragraph (b) (2) of this section. Then, convert the emissions of each GHG to metric tons CO₂e per year using Equation A-1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton CO₂ per year threshold for importers and exporters of coal-to-liquid products under paragraph (a) (4) (i) of this section, calculate the mass in metric tons per year of CO₂ that would result from the complete combustion or oxidation of the quantity of coal-to-liquid products that are imported during the reporting year and

that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart LL of this part.

(e) To calculate GHG quantities for comparison to the 25,000 metric ton CO₂e per year threshold for importers and exporters of petroleum products under paragraph (a)(4)(ii) of this section, calculate the mass in metric tons per year of CO₂ that would result from the complete combustion or oxidation of the volume of petroleum products and natural gas liquids that are imported during the reporting year and that are exported during the reporting year. Calculate the emissions using the methodology specified in subpart MM of this part.

(f) To calculate GHG quantities for comparison to the 25,000 metric ton CO₂e per year threshold under paragraph (a)(4) of this section for importers and exporters of industrial greenhouse gases and for importers and exporters of CO₂, the owner or operator shall calculate the mass in metric tons per year of CO₂e imports and exports as described in paragraphs (f)(1) through (f)(3) of this section.

(1) Calculate the mass in metric tons per year of CO₂, N₂O, and each fluorinated GHG that is imported and the mass in metric tons per year of CO₂, N₂O, and each fluorinated

GHG that is exported during the year. Include only those gases listed in Table A-1 of this subpart.

(2) Convert the mass of each imported and each GHG exported from paragraph (f)(1) of this section to metric tons of CO₂e using Equation A-1 of this section.

(3) Sum the total annual metric tons of CO₂e in paragraph (f)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO₂e in paragraph (f)(2) of this section for all exported GHGs.

(g) If a capacity or generation reporting threshold in paragraph (a)(1) of this section applies, the owner or operator shall review the appropriate records and perform any necessary calculations to determine whether the threshold has been exceeded.

(h) An owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule. Such owner or operator would become subject to the rule and reporting requirements §98.3(b)(3), if a facility or supplier exceeds the applicability requirements of paragraph (a) of this section at a later time. Thus, the owner or operator should reevaluate the applicability to this part (including the revising of any relevant emissions calculations or other calculations) whenever there is any

change that could cause a facility or supplier to meet the applicability requirements of paragraph (a) of this section. Such changes include but are not limited to process modifications, increases in operating hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion.

(i) Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year.

(1) If reported emissions are less than 25,000 metric tons CO₂e per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO₂e per year. The owner or operator must maintain the

corresponding records required under §98.3(g) for each of the five consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO₂e per year or more.

(2) If reported emissions are less than 15,000 metric tons CO₂e per year for three consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than 15,000 tons CO₂e per year. The owner or operator must maintain the corresponding records required under §98.3(g) for each of the three consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO₂e per year or more.

(3) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and

operations listed in paragraphs (a) (1) through (a) (4) of this section cease to operate, then the owner or operator is exempt from reporting in the years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all GHG-emitting processes and operations. This paragraph (i) (2) does not apply to seasonal or other temporary cessation of operations. This paragraph (i) (2) does not apply to facilities with municipal solid waste landfills. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation.

(j) Table A-2 of this subpart provides a conversion table for some of the common units of measure used in part 98.

§98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?

The owner or operator of a facility or supplier that is subject to the requirements of this part must submit GHG reports to the Administrator, as specified in this section.

(a) General. Except as provided in paragraph (d) of this section, follow the procedures for emission

calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) Schedule. The annual GHG report must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year.

(1) For an existing facility or supplier that began operation before January 1, 2010, report emissions for calendar year 2010 and each subsequent calendar year.

(2) For a new facility or supplier that begins operation on or after January 1, 2010, report emissions beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, 2010, report emissions for the first calendar year in which the change occurs, beginning with the first month of the change and ending on December 31 of that year. For a facility or supplier that becomes subject to this rule solely because of an increase in hours of operation or level of production, the first month of the change is the month in which the increased

hours of operation or level of production, if maintained for the remainder of the year, would cause the facility or supplier to exceed the applicable threshold. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(c) Content of the annual report. Except as provided in paragraph (d) of this section, each annual GHG report shall contain the following information:

(1) Facility name or supplier name (as appropriate) and physical street address including the city, state, and zip code.

(2) Year and months covered by the report.

(3) Date of submittal.

(4) For facilities, report annual emissions of CO₂, CH₄, N₂O, and each fluorinated GHG (as defined in §98.6) 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 this paragraph

(4) (iii) (A) through (4) (iii) (E).

(A) Biogenic CO₂.

(B) CO₂ (excluding biogenic CO₂).

(C) CH₄.

(D) N₂O.

(E) Each fluorinated GHG (including those not listed in Table A-1 of this subpart).

(iv) Emissions 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.

(5) For suppliers, report annual quantities of CO₂, CH₄, N₂O, and each fluorinated GHG (as defined in §98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:

(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in subparts KK through PP

of this part and expressed in metric tons of CO₂e calculated using Equation A-1 of this subpart.

(ii) Quantity of each GHG from each applicable supply category in subparts KK through PP of this part, expressed in metric tons of each GHG. For fluorinated GHG, report emissions of all fluorinated GHG, including those not listed in Table A-1 of this subpart.

(iii) Any other data specified in the "Data reporting requirements" section of each applicable subpart of this part.

(6) A written explanation, as required under §98.3(e), if you change emission calculation methodologies during the reporting period.

(7) A brief description of each "best available monitoring method" used according to paragraph (d) of this section, the parameter measured using the method, and the time period during which the "best available monitoring method" was used.

(8) 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.

(9) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of §98.4(e)(1).

(d) Special provisions for reporting year 2010.

(1) Best available monitoring methods. During January 1, 2010 through March 31, 2010, owners or operators may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the "Calculating GHG Emissions" sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Starting no later than April 1, 2010, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (d)(2) and (d)(3) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of an relevant subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) Requests for extension of the use of best available monitoring methods. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31, 2010.

(i) Timing of request. The extension request must be submitted to EPA no later than 30 days after the effective date of the GHG reporting rule.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific item of monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.

(B) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.

(C) A description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2010, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between promulgation of this part and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as

soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) Approval Criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. The use of best available methods will not be approved beyond December 31, 2010.

(3) Abbreviated emissions report for facilities containing only general stationary fuel combustion sources.

In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that meets the conditions of §98.2 (a) (3) may submit an abbreviated GHG report for the facility for GHGs emitted in 2010. The abbreviated report must be submitted by March 31, 2011. An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2011. The abbreviated facility report must include the following information:

(i) Facility name and physical street address including the city, state and zip code.

(ii) The year and months covered by the report.

(iii) Date of submittal.

(iv) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any method specified in §98.33(a) and expressed in metric tons of CO₂, CH₄, N₂O, and CO₂e.

(v) Any facility operating data or process information used for the GHG emission calculations.

(vi) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of paragraph (e) (1) of this section.

(e) Emission Calculations. In preparing the GHG report, you must use the calculation methodologies specified in the relevant subparts, except as specified in paragraph (d) of this section. For each source category, you must use the same calculation methodology throughout a reporting period unless you provide a written explanation of why a change in methodology was required.

(f) Verification. To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c) (8) and (d) (3) (vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected

reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.

(g) Recordkeeping. An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph. Retain all required records for at least 3 years. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by

fuel or material type. These data include but are not limited to the following information in this paragraph

(g) (2):

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors.

(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.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record 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.

(5) A written GHG Monitoring Plan.

(i) At a minimum, the GHG Monitoring Plan shall include the elements listed in this paragraph (i).

(A) Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

(B) Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

(C) 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 this part.

(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 or appendix B to 40 CFR part 75, and other documents) provided that the elements required by paragraph (g) (5) (i) of this section are easily recognizable.

(iii) The owner or operator shall revise the GHG Monitoring Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

(iv) Upon request by the Administrator, the owner or operator shall make all information that is collected in conformance with the GHG Monitoring Plan available for review during an audit. Electronic storage of the information in the plan is permissible, provided that the information can be made available in hard copy upon request during an audit.

(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.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(h) Annual GHG report revisions. The owner or operator shall 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. The owner or operator shall retain documentation for 3 years to support any revisions made to an annual GHG report.

(i) Calibration Accuracy Requirements. The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the calibration accuracy requirements of this paragraph (i).

(1) Except as provided paragraphs (i)(4) through (i)(6) of this section, flow meters and other devices (e.g., belt scales) that measure data used to calculate GHG emissions shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph and each relevant subpart of this part. All measurement devices must

be calibrated according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified in a relevant subpart of this part. All measurement devices shall be calibrated to an accuracy of 5 percent. For facilities and suppliers that become subject to this part after April 1, 2010, the initial calibration shall be conducted on the date that data collection is required to begin. Subsequent calibrations shall be performed at the frequency specified in each applicable subpart.

(2) For flow meters, perform all calibrations at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A-2 of this section. The terms "R" and "A" in Equation A-2 must be expressed in consistent units of measure (e.g., gallons/minute, ft³/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

$$CE = \frac{R-A}{R} \times 100 \quad (\text{Eq. A-2})$$

Where:

CE = Calibration error (%)
 R = Reference value
 A = Flow meter response to the reference value

(3) For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (ΔP), total pressure, and temperature transmitters. Calibrate each transmitter at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. Calculate the calibration error of each transmitter at each measurement point, using Equation A-3 of this subpart. The terms "R", "A", and "FS" in Equation A-3 of this subpart must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 5.0 percent.

$$CE = \frac{R - A}{FS} \times 100 \quad (\text{Eq. A-3})$$

Where:

CE = Calibration error (%)
R = Reference value
A = Transmitter response to the reference value
FS = Full-scale value of the transmitter

(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.

(5) For a flow meter or other measurement device that has been previously calibrated in accordance with this part, an initial calibration is not required by the date specified in paragraph (i)(1) of this section if, as of the date required for the initial calibration, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations, as required by this part, has not elapsed).

(6) For units and processes that operate continuously with infrequent outages, it may not be possible to meet the April 1, 2010 deadline for the initial calibration of a flow meter or other measurement device without removing the device from service and shipping it to a remote location, thereby disrupting normal process operation. 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).

§98.4 Authorization and Responsibilities of the Designated Representative.

(a) General. Except as provided under paragraph (f) of this section, each facility, and each supplier, that is subject to this part, shall have one and only one designated representative, who shall be responsible for certifying, signing, and submitting GHG emissions reports and any other submissions for such facility and supplier respectively to the Administrator under this part. 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, 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.

(b) Authorization of a designated representative.

The designated representative of the facility or supplier

shall be an individual selected by an agreement binding on the owners and operators of such facility or supplier and shall act in accordance with the certification statement in paragraph (i) (4) (iv) of this section.

(c) Responsibility of the designated representative.

Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of such facility or supplier in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) Timing. No GHG emissions report or other submissions under this part for a facility or supplier will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the facility or supplier. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the

facility's or supplier's initial emission report under this part.

(e) Certification of the GHG emissions report. Each GHG emission report and any other submission under this part for a facility or supplier shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the facility or supplier in accordance with this section and §3.10.

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements

and information, including the possibility of fine or imprisonment.”

(2) The Administrator will accept a GHG emission report or other submission for a facility or supplier under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) Alternate designated representative. A certificate of representation under this section for a facility or supplier may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owners and operators, and may act on behalf of the designated representative, of such facility or supplier. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier identifying an alternate designated representative.

(i) The alternate designated representative may act on behalf of the designated representative for such facility or supplier.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.

(2) Except in this section, whenever the term "designated representative" is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.

(g) Changing a designated representative or alternate designated representative. The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a facility or supplier received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the facility or supplier. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the facility or supplier before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owners and operators of the facility or supplier.

(h) Changes in owners and operators. In the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier, as if the owner or operator were included in such list. Within 90 days after any change in the owners and operators of the facility or supplier (including the addition of a new owner or operator), the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section except that such list shall be amended to reflect the change. If the designated representative or alternate designated representative determines at any time that an owner or operator of the facility or supplier is not included in such list and such exclusion is not the result of a change in the owners and operators, the designated representative or any alternate designated representative shall submit, within 90 days of making such determination, a certificate of representation

that is complete under this section except that such list shall be amended to include such owner or operator.

(i) Certificate of representation. A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

(1) Identification of the facility or supplier for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility or supplier identified in paragraph (i)(1) of this section, provided that, if the list includes the operators of the facility or supplier and the owners with control of the facility or supplier, the failure to include any other owners shall not make the certificate of representation incomplete.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) "I certify that I was selected as the designated representative or alternate designated representative, as

applicable, by an agreement binding on the owners and operators of the facility or supplier, as applicable."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 98 on behalf of the owners and operators of the facility or supplier, as applicable, and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions."

(iii) "I certify that the owners and operators of the facility or supplier, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the facility or supplier."

(iv) "If there are multiple owners and operators of the facility or supplier, as applicable, I certify that I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the facility or supplier."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) Documents of agreement. Unless otherwise required by the Administrator, documents of agreement

referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) Binding nature of the certificate of representation. Once a complete certificate of representation under this section for a facility or supplier has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility or supplier is received by the Administrator.

(l) Objections concerning a designated representative.

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

(m) Delegation by designated representative and alternate designated representative.

(1) A designated representative or an alternate designated representative may delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator provided for or required under this part, except for a submission under this paragraph.

(2) In order to delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator in accordance with paragraph (m) (1) of this section, the designated representative or alternate designated representative must submit electronically to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(i) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if

any) of such designated representative or alternate designated representative.

(ii) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such individual (referred to as an "agent").

(iii) For each such individual, a list of the type or types of electronic submissions under paragraph (m)(1) of this section for which authority is delegated to him or her.

(iv) For each type of electronic submission listed in accordance with clause (iii), the facility or supplier for which the electronic submission may be made.

(v) The following certification statements by such designated representative or alternate designated representative:

(A) "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed, and for a facility or supplier designated, for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as applicable, and before this notice of delegation is superseded by another notice of delegation under

§98.4(m) (3) shall be deemed to be an electronic submission certified, signed, and submitted by me.”

(B) “Until this notice of delegation is superseded by a later signed notice of delegation under §98.4(m) (3), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under §98.4(m) is terminated.”.

(v) The signature of such designated representative or alternate designated representative and the date signed.

(3) A notice of delegation submitted in accordance with paragraph (m) (2) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of another such notice that was signed later by such designated representative or alternate designated representative, as applicable. The later signed notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(4) Any electronic submission covered by the certification in paragraph (m) (2) (iv) (A) of this section and made in accordance with a notice of delegation

effective under paragraph (m) (3) of this section shall be deemed to be an electronic submission certified, signed, and submitted by the designated representative or alternate designated representative submitting such notice of delegation.

§98.5 How is the report submitted?

Each GHG report and certificate of representation for a facility or supplier must be submitted electronically in accordance with the requirements of §98.4 and in a format specified by the Administrator.

§98.6 Definitions.

All terms used in this part shall have the same meaning given in the Clean Air Act and in this section.

Accuracy of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that the mean of repeat measurements made by a device or technique are within 95 percent of the range bounded by the true value plus or minus the specified level.

Acid Rain Program means the program established under title IV of the Clean Air Act, and implemented under parts 72 through 78 of this chapter for the reduction of sulfur dioxide and nitrogen oxides emissions.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's authorized representative.

AGA means the American Gas Association

Alkali bypass means a duct between the feed end of the kiln and the preheater tower through which a portion of the kiln exit gas stream is withdrawn and quickly cooled by air or water to avoid excessive buildup of alkali, chloride and/or sulfur on the raw feed. This may also be referred to as the "kiln exhaust gas bypass."

Anaerobic digester means the system where wastes are collected and anaerobically digested in large containment vessels or covered lagoons. Anaerobic digesters stabilize waste by the microbial reduction of complex organic compounds to CO₂ and CH₄, which is captured and may be flared or used as fuel. Anaerobic digestion systems, include but are not limited to covered lagoon, complete mix, plug flow, and fixed film digesters.

Anaerobic lagoon means a type of liquid storage system component, either at manure management system or a wastewater treatment system, that is designed and operated to stabilize wastes using anaerobic microbial processes. Anaerobic lagoons may be designed for combined stabilization and storage with varying lengths of retention

time (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors.

Anode effect is a process upset condition of an aluminum electrolysis cell caused by too little alumina dissolved in the electrolyte. The anode effect begins when the voltage rises rapidly and exceeds a threshold voltage, typically 8 volts.

Anode Effect Minutes Per Cell Day (24 hours) are the total minutes during which an electrolysis cell voltage is above the threshold voltage, typically 8 volts.

ANSI means the American National Standards Institute.

API means the American Petroleum Institute.

Argon-oxygen decarburization (AOD) vessel means any closed-bottom, refractory-lined converter vessel with submerged tuyeres through which gaseous mixtures containing argon and oxygen or nitrogen may be blown into molten steel for further refining to reduce the carbon content of the steel.

ASABE means the American Society of Agricultural and Biological Engineers.

ASME means the American Society of Mechanical Engineers.

ASTM means the American Society of Testing and Materials.

Asphalt means a dark brown-to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

Aviation Gasoline means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM Specification D910-07a, Standard Specification for Aviation Gasolines (incorporated by reference, see §98.7).

B₀ means the maximum CH₄ producing capacity of a waste stream, kg CH₄/kg COD.

Basic oxygen furnace means any refractory-lined vessel in which high-purity oxygen is blown under pressure through a bath of molten iron, scrap metal, and fluxes to produce steel.

bb1 means barrel.

Biodiesel means a mono-akyl ester derived from biomass and conforming to ASTM D6751-08, Standard Specification for

Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels.

Biogenic CO₂ means carbon dioxide emissions generated as the result of biomass combustion from combustion units for which emission calculations are required by an applicable part 98 subpart.

Biomass means non-fossilized and biodegradable organic material originating from plants, animals or micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

Blast furnace means a furnace that is located at an integrated iron and steel plant and is used for the production of molten iron from iron ore pellets and other iron bearing materials.

Blendstocks are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

Blendstocks -- Others are products used for blending or compounding into finished motor gasoline that are not defined elsewhere. Excludes Gasoline Treated as Blendstock (GTAB), Diesel Treated as Blendstock (DTAB), conventional blendstock for oxygenate blending (CBOB), reformulated blendstock for oxygenate blending (RBOB), oxygenates (e.g. fuel ethanol and methyl tertiary butyl ether), butane, and pentanes plus.

Blowdown mean the act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

British Thermal Unit or Btu means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

Bulk, with respect to industrial GHG suppliers and CO2 suppliers, means the transfer of a product inside containers, including but not limited to tanks, cylinders, drums, and pressure vessels.

Bulk natural gas liquid or NGL refers to mixtures of hydrocarbons that have been separated from natural gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGL is sold to

fractionators or to refineries and petrochemical plants where the fractionation takes place.

Butane, or n-Butane, is a paraffinic straight-chain hydrocarbon with molecular formula C_4H_{10} .

Butylene, or n-Butylene, is an olefinic straight-chain hydrocarbon with molecular formula C_4H_8 .

By-product coke oven battery means a group of ovens connected by common walls, where coal undergoes destructive distillation under positive pressure to produce coke and coke oven gas from which by-products are recovered.

Calcination means the process of thermally treating minerals to decompose carbonates from ore.

Calculation methodology means a methodology prescribed under the section "Calculating GHG Emissions" in any subpart of part 98.

Carbon dioxide equivalent or CO₂e means the number of metric tons of CO₂ emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A-1 of this subpart.

Carbon dioxide production well means any hole drilled in the earth for the primary purpose of extracting carbon dioxide from a geologic formation or group of formations which contain deposits of carbon dioxide.

Carbon dioxide production well facility means one or more carbon dioxide production wells that are located on one or more contiguous or adjacent properties, which are under the control of the same entity. Carbon dioxide production wells located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line, or pipeline, shall be considered part of the same CO₂ production well facility if they otherwise meet the definition.

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (e.g. a power plant or other industrial facility) or extracted from a carbon dioxide production well plus incidental associated substances either derived from the source materials and the capture process or extracted with the carbon dioxide.

Carbon share means the percent of total mass that carbon represents in any product..

Carbonate means compounds containing the radical CO₃⁻². Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO₂). Common carbonates consumed in the mineral industry include calcium carbonate (CaCO₃) or

calcite; magnesium carbonate (MgCO_3) or magnesite; and calcium-magnesium carbonate ($\text{CaMg}(\text{CO}_3)_2$) or dolomite.

Carbonate-based mineral means any of the following minerals used in the manufacture of glass: calcium carbonate (CaCO_3), calcium magnesium carbonate ($\text{CaMg}(\text{CO}_3)_2$), and sodium carbonate (Na_2CO_3).

Carbonate-based mineral mass fraction means the following: for limestone, the mass fraction of CaCO_3 in the limestone; for dolomite, the mass fraction of $\text{CaMg}(\text{CO}_3)_2$ in the dolomite; and for soda ash, the mass fraction of Na_2CO_3 in the soda ash.

Carbonate-based raw material means any of the following materials used in the manufacture of glass: limestone, dolomite, and soda ash.

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems,

which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

Deep bedding systems for cattle swine means a manure management system in which, as manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.

CBOB-Summer (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Summer.

CBOB-Winter (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Winter.

Certified standards means calibration gases certified by the manufacturer of the calibration gases to be accurate

to within 2 percent of the value on the label or calibration gases.

CH₄ means methane.

Chemical recovery combustion unit means a combustion device, such as a recovery furnace or fluidized-bed reactor where spent pulping liquor from sulfite or semi-chemical pulping processes is burned to recover pulping chemicals.

Chemical recovery furnace means an enclosed combustion device where concentrated spent liquor produced by the kraft or soda pulping process is burned to recover pulping chemicals and produce steam. Includes any recovery furnace that burns spent pulping liquor produced from both the kraft and soda pulping processes.

Chloride process means a production process where titanium dioxide is produced using calcined petroleum coke and chlorine as raw materials.

City gate means a location at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer. In this rule, in keeping with common practice, the term refers to a point or measuring station at which a local gas distribution utility receives gas from a natural gas pipeline company or transmission system. Meters at the city gate station measure the flow of natural gas into the local distribution

company system and typically are used to measure local distribution company system sendout to customers.

CO₂ means carbon dioxide.

Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388-05 Standard Classification of Coals by Rank (incorporated by reference, see §98.7).

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

Coke burn-off means the coke removed from the surface of a catalyst by combustion during catalyst regeneration. Coke burn-off also means the coke combusted in fluid coking unit burner.

Cokemaking means the production of coke from coal in either a by-product coke oven battery or a non-recovery coke oven battery.

Commercial Applications means executing a commercial transaction subject to a contract. A commercial application includes transferring custody of a product from one facility to another if it otherwise meets the definition.

Company records means, in reference to the amount of fuel consumed by a stationary combustion unit (or by a group of such units), a complete record of the methods

used, the measurements made, and the calculations performed to quantify fuel usage. Company records may include, but are not limited to, direct measurements of fuel consumption by gravimetric or volumetric means, tank drop measurements, and calculated values of fuel usage obtained by measuring auxiliary parameters such as steam generation or unit operating hours. Fuel billing records obtained from the fuel supplier qualify as company records.

Connector means to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this part.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in North American Industry Classification System 327213 (NAICS 327213).

Continuous emission monitoring system or CEMS means the total equipment required to sample, analyze, measure, and provide, by means of readings recorded at least once

every 15 minutes, a permanent record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources.

Continuous glass melting furnace means a glass melting furnace that operates continuously except during periods of maintenance, malfunction, control device installation, reconstruction, or rebuilding.

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, but which meet summer RVP standards required under 40 CFR 80.27 or as specified by the state. Note: This category excludes conventional gasoline for oxygenate blending (CBOB) as well as other blendstock.

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 or the summer RVP standards required under 40 CFR 80.27 or as specified by the state. Note: This category excludes

conventional blendstock for oxygenate blending (CBOB) as well as other blendstock.

Crude oil means a mixture of hydrocarbons that exists in the liquid phase in the underground reservoir and remains liquid at atmospheric pressure after passing through surface separating facilities.

Daily spread means a manure management system component in which manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.

Day means any consistently designated 24 hour period during which an emission unit is operated.

Degradable organic carbon (DOC) means the fraction of the total mass of a waste material that can be biologically degraded.

Delayed coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed_coking unit consists of the coke drums and ancillary equipment associated with a single fractionator.

Density means the mass contained in a given unit volume (mass/volume).

Destruction means, with respect to landfills and manure management, the combustion of methane in any on-site or off-site combustion technology. Destroyed methane includes, but is not limited to, methane combusted by flaring, methane destroyed by thermal oxidation, methane combusted for use in on-site energy or heat production technologies, methane that is conveyed through pipelines (including natural gas pipelines) for off-site combustion, and methane that is collected for any other on-site or off-site use as a fuel.

Destruction means, with respect to fluorinated GHGs, the expiration of a fluorinated GHG to the destruction efficiency actually achieved. Such destruction does not result in a commercially useful end product.

Destruction Efficiency means the efficiency with which a destruction device reduces the GWP-weighted mass of greenhouse gases fed into the device, considering the GWP-weighted masses of both the greenhouse gases fed into the device and those exhausted from the device. The Destruction Efficiency is expressed in Equation A-2 of this section:

$$DE = 1 - \frac{tCO_2e_{OUT}}{tCO_2e_{IN}} \quad (\text{Eq. A-2})$$

Where:

DE	=	Destruction Efficiency
tCO ₂ e _{IN}	=	The GWP-weighted mass of GHGs fed into the destruction device
tCO ₂ e _{OUT}	=	The GWP-weighted mass of GHGs exhausted from the destruction device, including GHGs formed during the destruction process

Destruction efficiency, or flaring destruction efficiency, refers to the fraction of the gas that leaves the flare partially or fully oxidized.

Diesel-Other is any distillate fuel oil not defined elsewhere, including Diesel Treated as Blendstock (DTAB).

DIPE (diisopropyl ether, (CH₃)₂CHOCH(CH₃)₂) is an ether as described in "Oxygenates."

Direct liquefaction means the conversion of coal directly into liquids, rather than passing through an intermediate gaseous state.

Direct reduction furnace means a high temperature furnace typically fired with natural gas to produce solid iron from iron ore or iron ore pellets and coke, coal, or other carbonaceous materials.

Distillate Fuel Oil means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term distillate fuel oil includes kerosene, diesel fuels (Diesel Fuels No. 1, No. 2,

and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

Distillate Fuel No. 1 has a maximum distillation temperature of 550 °F at the 90 percent recovery point and a minimum flash point of 100 °F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

Distillate Fuel No. 2 has a minimum and maximum distillation temperature of 540 °F and 640 °F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

Distillate Fuel No. 4 is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131 °F.

DOC_f means the fraction of DOC that actually decomposes under the (presumably anaerobic) conditions within the landfill.

Dry lot means a manure management system component consisting of a paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.

Electric arc furnace (EAF) means a furnace that produces molten alloy metal and heats the charge materials with electric arcs from carbon electrodes.

Electric arc furnace steelmaking means the production of carbon, alloy, or specialty steels using an EAF. This definition excludes EAFs at steel foundries and EAFs used to produce nonferrous metals.

Electrothermic furnace means a furnace that heats the charged materials with electric arcs from carbon electrodes.

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance

testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

ETBE (ethyl tertiary butyl ether, $(\text{CH}_3)_3\text{COC}_2\text{H}_5$) is an ether as described in "Oxygenates."

Ethane is a paraffinic hydrocarbon with molecular formula C_2H_6 .

Ethanol is an anhydrous alcohol with molecular formula $\text{C}_2\text{H}_5\text{OH}$.

Ethylene is an olefinic hydrocarbon with molecular formula C_2H_4 .

Ex refinery gate means the point at which a petroleum product leaves the refinery.

Experimental furnace means a glass melting furnace with the sole purpose of operating to evaluate glass melting processes, technologies, or glass products. An experimental furnace does not produce glass that is sold (except for further research and development purposes) or

that is used as a raw material for non-experimental furnaces.

Export means to transport a product from inside the United States to persons outside the United States, excluding any such transport on behalf of the United States military including foreign military sales under the Arms Export Control Act.

Exporter means any person, company or organization of record that transfers for sale or for other benefit, domestic products from the United States to another country or to an affiliate in another country, excluding any such transfers on behalf of the United States military or military purposes including foreign military sales under the Arms Export Control Act. An exporter is not the entity merely transporting the domestic products, rather an exporter is the entity deriving the principal benefit from the transaction.

Facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such

installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

Feed means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust and flyash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

Feedstock means raw material inputs to a process that are transformed by reaction, oxidation, or other chemical or physical methods into products and by-products. Supplemental fuel burned to provide heat or thermal energy is not a feedstock.

Fischer-Tropsch process means a catalyzed chemical reaction in which synthesis gas, a mixture of carbon monoxide and hydrogen, is converted into liquid hydrocarbons of various forms.

Flare means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in NAICS 327211.

Flowmeter means a device that measures the mass or volumetric rate of flow of a gas, liquid, or solid moving through an open or closed conduit (e.g. flowmeters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flowmeters, and vortex flowmeters).

Fluid coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The fluid coking unit includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent. There are two basic types of fluid coking units: a traditional fluid coking unit in which only a small portion of the coke produced in the unit is burned to fuel the unit and the fluid coking burner exhaust vent is directed to the atmosphere (after processing in a CO boiler or other air pollutant control equipment) and a flexicoking unit in which an auxiliary burner is used to partially combust a significant portion of the produced petroleum coke to

generate a low value fuel gas that is used as fuel in other combustion sources at the refinery.

Fluorinated greenhouse gas means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C. With these exceptions, "fluorinated GHG" includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for example, consumer products that are derived from such materials and are combusted.

Fossil fuel-fired means powered by combustion of fossil fuel, alone or in combination with any other fuel, regardless of the percentage of fossil fuel consumed.

Fractionators means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus (C_5+). Plants that only process natural gas but do not fractionate NGLs

further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

Fuel means solid, liquid or gaseous combustible material.

Fuel gas means gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and, if necessary, units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects fuel gas from one or more sources for treatment, as necessary, and transport to a stationary combustion unit. A fuel gas system may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the various combustion units at the refinery or petrochemical plant.

Gas collection system or landfill gas collection system means a system of pipes used to collect landfill gas from different locations in the landfill to a single

location for treatment (thermal destruction) or use.

Landfill gas collection systems may also include knock-out or separator drums and/or a compressor.

Gas-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of gaseous fuels, and the remainder of its annual heat input from the combustion of fuel oil or other liquid fuels.

Gas monitor means an instrument that continuously measures the concentration of a particular gaseous species in the effluent of a stationary source.

Gaseous fuel means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

Gasification means the conversion of a solid or liquid raw material into a gas.

Gasoline - Other is any gasoline that is not defined elsewhere, including GTAB (gasoline treated as blendstock).

Glass melting furnace means a unit comprising a refractory-lined vessel in which raw materials are charged and melted at high temperature to produce molten glass.

Glass produced means the weight of glass exiting a glass melting furnace.

Global warming potential or GWP means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram- of a reference gas, i.e., CO₂.

GPA means the Gas Processors Association.

Greenhouse gas or GHG means carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), sulfur hexafluoride (SF₆), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

GTBA (gasoline-grade tertiary butyl alcohol, (CH₃)₃COH), or t-butanol, is an alcohol as described in "Oxygenates."

Heavy Gas Oils are petroleum distillates with an approximate boiling range from 651 °F to 1,000 °F.

Heel means the amount of gas that remains in a shipping container after it is discharged or off-loaded (that is no more than ten percent of the volume of the container).

High heat value or HHV means the high or gross heat content of the fuel with the heat of vaporization included. The water is assumed to be in a liquid state.

Hydrofluorocarbons or HFCs means a class of GHGs consisting of hydrogen, fluorine, and carbon.

Import means, to land on, bring into, or introduce into, any place subject to the jurisdiction of the United States whether or not such landing, bringing, or introduction constitutes an importation within the meaning of the customs laws of the United States, with the following exemptions:

(1) Off-loading used or excess fluorinated GHGs or nitrous oxide of U.S. origin from a ship during servicing.

(2) Bringing fluorinated GHGs or nitrous oxide into the U.S. from Mexico where the fluorinated GHGs or nitrous oxide had been admitted into Mexico in bond and were of U.S. origin.

(3) Bringing fluorinated GHGs or nitrous oxide into the U.S. when transported in a consignment of personal or household effects or in a similar non-commercial situation normally exempted from U.S. Customs attention.

(4) Bringing fluorinated GHGs or nitrous into U.S. jurisdiction exclusively for U. S. military purposes.

Importer means any person, company, or organization of record that for any reason brings a product into the United States from a foreign country, excluding introduction into U.S. jurisdiction exclusively for United States military purposes. An importer is the person, company, or organization primarily liable for the payment of any duties

on the merchandise or an authorized agent acting on their behalf. The term includes, as appropriate:

- (1) The consignee.
- (2) The importer of record.
- (3) The actual owner.

(4) The transferee, if the right to draw merchandise in a bonded warehouse has been transferred.

Indurating furnace means a furnace where unfired taconite pellets, called green balls, are hardened at high temperatures to produce fired pellets for use in a blast furnace. Types of indurating furnaces include straight gate and grate kiln furnaces.

Industrial greenhouse gases means nitrous oxide or any fluorinated greenhouse gas.

In-line kiln/raw mill means a system in a portland cement production process where a dry kiln system is integrated with the raw mill so that all or a portion of the kiln exhaust gases are used to perform the drying operation of the raw mill, with no auxiliary heat source used. In this system the kiln is capable of operating without the raw mill operating, but the raw mill cannot operate without the kiln gases, and consequently, the raw mill does not generate a separate exhaust gas stream.

Isobutane is a paraffinic branch chain hydrocarbon with molecular formula C_4H_{10} .

Isobutylene is an olefinic branch chain hydrocarbon with molecular formula C_4H_8 .

Kerosene is a light petroleum distillate with a maximum distillation temperature of 400 °F at the 10-percent recovery point, a final maximum boiling point of 572 °F, a minimum flash point of 100 °F, and a maximum freezing point of -22 °F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. Excluded is kerosene-type jet fuel (see definition herein).

Kerosene-Type Jet Fuel means a kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572 °F. Included are Jet A, Jet A-1, JP-5, and JP-8.

Kiln means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

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.

Landfill gas means gas produced as a result of anaerobic decomposition of waste materials in the landfill. Landfill gas generally contains 40 to 60 percent methane on a dry basis, typically less than 1 percent non-methane organic chemicals, and the remainder being carbon dioxide.

Lime is the generic term for a variety of chemical compounds that are produced by the calcination of limestone or dolomite. These products include but are not limited to calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, and dolomitic hydrate.

Liquid/Slurry means a manure management component in which manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods less than one year.

Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Petroleum lubricants may be produced from distillates or residues.

Makeup chemicals means carbonate chemicals (e.g., sodium and calcium carbonates) that are added to the

chemical recovery areas of chemical pulp mills to replace chemicals lost in the process.

Manure composting means the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production. There are four types of composting employed for manure management: static, in vessel, intensive windrow and passive windrow. Static composting typically occurs in an enclosed channel, with forced aeration and continuous mixing. In vessel composting occurs in piles with forced aeration but no mixing. Intensive windrow composting occurs in windrows with regular turning for mixing and aeration. Passive windrow composting occurs in windrows with infrequent turning for mixing and aeration.

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.

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).

Mcf means thousand cubic feet.

Methane conversion factor means the extent to which the CH₄ producing capacity (B₀) is realized in each type of treatment and discharge pathway and system. Thus, it is an indication of the degree to which the system is anaerobic.

Methane correction factor means an adjustment factor applied to the methane generation rate to account for portions of the landfill that remain aerobic. The methane correction factor can be considered the fraction of the total landfill waste volume that is ultimately disposed of in an anaerobic state. Managed landfills that have soil or other cover materials have a methane correction factor of 1.

Methanol (CH₃OH) is an alcohol as described in "Oxygenates."

Midgrade gasoline has an octane rating greater than or equal to 88 and less than or equal to 90. This definition applies to the midgrade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For midgrade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished

gasoline after oxygenate has been added to the RBOB or CBOB.

Miscellaneous Products include all refined petroleum products not defined elsewhere. It includes, but is not limited to, naphtha-type jet fuel (Jet B and JP-4), petrolatum lube refining by-products (aromatic extracts and tars), absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, waste feedstocks, and specialty oils. It excludes organic waste sludges, tank bottoms, spent catalysts, and sulfuric acid.

MMBtu means million British thermal units.

Motor gasoline (finished) means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline includes conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

Mscf means million standard cubic feet.

MTBE (methyl tertiary butyl ether, $(\text{CH}_3)_3\text{COCH}_3$) is an ether as described in "Oxygenates."

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) such as commercial solid waste, nonhazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste. Portions of an MSW landfill may be separated by access roads, public roadways, or other public right-of-ways. An MSW landfill may be publicly or privately owned.

Municipal solid waste or MSW means solid phase household, commercial/retail, and/or institutional waste, such as, but not limited to, yard waste and refuse.

N₂O means nitrous oxide.

Naphthas (< 401 °F) is a generic term applied to a petroleum fraction with an approximate boiling range between 122 °F and 400 °F. The naphtha fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

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. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

Natural Gas Liquids (NGLs) means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

Natural gasoline means a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane.

NIST means the United States National Institute of Standards and Technology.

Nitric acid production line means a series of reactors and absorbers used to produce nitric acid.

Nitrogen excreted is the nitrogen that is excreted by livestock in manure and urine.

Non-crude feedstocks means any petroleum product or natural gas liquid that enters the refinery as a feedstock to be further refined or otherwise used on site.

Non-recovery coke oven battery means a group of ovens connected by common walls and operated as a unit, where coal undergoes destructive distillation under negative pressure to produce coke, and which is designed for the combustion of the coke oven gas from which by-products are not recovered.

Oil-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of fuel oil, and the remainder of its annual heat input from the combustion of natural gas or other gaseous fuels.

Open-ended valve or Lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operating hours means the duration of time in which a process or process unit is utilized; this excludes shutdown, maintenance, and standby.

Operational change means, for purposes of §98.3(b), a change in the type of feedstock or fuel used, a change in operating hours, or a change in process production rate.

Operator means any person who operates or supervises a facility or supplier.

Other Oils (> 401 °F) are oils with a boiling range equal to or greater than 401 °F that are generally intended for use as a petrochemical feedstock and are not defined elsewhere.

Owner means any person who has legal or equitable title to, has a leasehold interest in, or control of a facility or supplier, except a person whose legal or equitable title to or leasehold interest in the facility or supplier arises solely because the person is a limited partner in a partnership that has legal or equitable title to, has a leasehold interest in, or control of the facility or supplier shall not be considered an "owner" of the facility or supplier.

Oxygenates means substances which, when added to gasoline, increase the oxygen content of the gasoline. Common oxygenates are ethanol, methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME), diisopropyl ether (DIPE), and methanol.

Pasture/Range/Paddock means the manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.

Pentanes Plus, or C5+, is a mixture of hydrocarbons that is a liquid at ambient temperature and pressure, and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes, but is not limited to, normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

Perfluorocarbons or PFCs means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

Petrochemical means methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, and any form of carbon black.

Petrochemical Feedstocks means feedstocks derived from petroleum for the manufacture of chemicals, synthetic rubber, and a variety of plastics. This category is usually divided into naphthas less than 401 °F and other oils greater than 401 °F.

Petroleum means oil removed from the earth and the oil derived from tar sands and shale.

Petroleum coke means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and may

be used as a feedstock in coke ovens. This product is also known as marketable coke or catalyst coke.

Petroleum product means all refined and semi-refined products that are produced at a refinery by processing crude oil and other petroleum-based feedstocks, including petroleum products derived from co-processing biomass and petroleum feedstock together, but not including plastics or plastic products. Petroleum products may be combusted for energy use, or they may be used either for non-energy processes or as non-energy products. The definition of petroleum product for importers and exporters excludes waxes.

Pit storage below animal confinement (deep pits) means the collection and storage of manure typically below a slatted floor in an enclosed animal confinement facility. This usually occurs with little or no added water for periods less than one year.

Portable means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.

(2) The equipment or a replacement resides at the same location for more than 12 consecutive months.

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

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

Poultry manure with litter means a manure management system component that is similar to cattle and swine deep bedding except usually not combined with a dry lot or pasture. The system is typically used for poultry breeder flocks and for the production of meat type chickens (broiler) and other fowl.

Poultry manure without litter means a manure management system component that may manage manure in a liquid form, similar to open pits in enclosed animal confinement facilities. These systems may alternatively be designed and operated to dry manure as it accumulates. The latter is known as a high-rise manure management system and is a form of passive windrow manure composting when designed and operated properly.

Precision of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that 95 percent of repeat measurements made by a device or technique are within the range bounded by the mean of the measurements plus or minus the specified level.

Premium grade gasoline is gasoline having an antiknock index, i.e., octane rating, greater than 90. This definition applies to the premium grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For premium grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Pressed and blown glass means glass which is pressed, blown, or both, into products such as light bulbs, glass fiber, technical glass, and other products listed in NAICS 327212.

Pressure relief device or pressure relief valve or pressure safety valve means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device is but not limited to a spring-

loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

Process emissions means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO₂ emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

Process unit means the equipment assembled and connected by pipes and ducts to process raw materials and to manufacture either a final product or an intermediate used in the onsite production of other products. The process unit also includes the purification of recovered byproducts.

Process vent means means a gas stream that: (1) is discharged through a conveyance to the atmosphere either directly or after passing through a control device; (2) originates from a unit operation, including but not limited to reactors (including reformers, crackers, and furnaces,

and separation equipment for products and recovered byproducts); and (3) contains or has the potential to contain GHG that is generated in the process. Process vent does not include safety device discharges, equipment leaks, gas streams routed to a fuel gas system or to a flare, discharges from storage tanks.

Propane is a paraffinic hydrocarbon with molecular formula C_3H_8 .

Propylene is an olefinic hydrocarbon with molecular formula C_3H_6 .

Pulp mill lime kiln means the combustion units (e.g., rotary lime kiln or fluidized bed calciner) used at a kraft or soda pulp mill to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

Pushing means the process of removing the coke from the coke oven at the end of the coking cycle. Pushing begins when coke first begins to fall from the oven into the quench car and ends when the quench car enters the quench tower.

Raw mill means a ball and tube mill, vertical roller mill or other size reduction equipment, that is not part of an in-line kiln/raw mill, used to grind feed to the appropriate size. Moisture may be added or removed from

the feed during the grinding operation. If the raw mill is used to remove moisture from feed materials, it is also, by definition, a raw material dryer. The raw mill also includes the air separator associated with the raw mill.

RBOB-Summer (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Summer.

RBOB-Winter (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Winter.

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 and 40 CFR 80.41, and summer RVP standards required under 40 CFR 80.27 or as specified by the state. Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

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 and 40 CFR 80.41, but which do not meet summer RVP standards required under 40 CFR 80.27 or as specified by the state.

Note: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

Regular grade gasoline is gasoline having an antiknock index, i.e., octane rating, greater than or equal to 85 and less than 88. This definition applies to the regular grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For regular grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Rendered animal fat, or tallow, means fats extracted from animals which are generally used as a feedstock in making biodiesel.

Research and development means those activities conducted in process units or at laboratory bench-scale settings whose purpose is to conduct research and

development for new processes, technologies, or products and whose purpose is not for the manufacture of products for commercial sale, except in a de minimis manner.

Residual Fuel Oil No. 5 (Navy Special) is a classification for the heavier fuel oil generally used in steam powered vessels in government service and inshore power plants. It has a minimum flash point of 131 °F.

Residual Fuel Oil No. 6 (a.k.a. Bunker C) is a classification for the heavier fuel oil generally used for the production of electric power, space heating, vessel bunkering and various industrial purposes. It has a minimum flash point of 140 °F.

Residuum is residue from crude oil after distilling off all but the heaviest components, with a boiling range greater than 1,000 °F.

Road Oil is any heavy petroleum oil, including residual asphaltic oil used as a dust palliative and surface treatment on roads and highways. It is generally produced in six grades, from 0, the most liquid, to 5, the most viscous.

Rotary lime kiln means a unit with an inclined rotating drum that is used to produce a lime product from limestone by calcination.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. A safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.

Semi-refined petroleum product means all oils requiring further processing. Included in this category are unfinished oils which are produced by the partial

refining of crude oil and include the following: naphthas and lighter oils; kerosene and light gas oils; heavy gas oils; and residuum, and all products that require further processing or the addition of blendstocks.

Sendout means, in the context of a local distribution company, the total deliveries of natural gas to customers over a specified time interval (typically hour, day, month, or year). Sendout is the sum of gas received through the city gate, gas withdrawn from on-system storage or peak shaving plants, and gas produced and delivered into the distribution system; and is net of any natural gas injected into on-system storage. It comprises gas sales, exchange, deliveries, gas used by company, and unaccounted for gas. Sendout is measured at the city gate station, and other on-system receipt points from storage, peak shaving, and production.

Sensor means a device that measures a physical quantity/quality or the change in a physical quantity/quality, such as temperature, pressure, flow rate, pH, or liquid level.

SF₆ means sulfur hexafluoride.

Shutdown means the cessation of operation of an emission source for any purpose.

Silicon carbide means an artificial abrasive produced from silica sand or quartz and petroleum coke.

Sinter process means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

Site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically located.

Smelting furnace means a furnace in which lead-bearing materials, carbon-containing reducing agents, and fluxes are melted together to form a molten mass of material containing lead and slag.

Solid storage is the storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a

sufficient amount of bedding material or loss of moisture by evaporation.

Sour gas means any gas that contains significant concentrations of hydrogen sulfide. Sour gas may include untreated fuel gas, amine stripper off-gas, or sour water stripper gas.

Special naphthas means all finished products with the naphtha boiling range (290° to 470 °F) that are generally used as paint thinners, cleaners or solvents. These products are refined to a specified flash point. Special naphthas include all commercial hexane and cleaning solvents conforming to ASTM Specification D1836-07, Standard Specification for Commercial Hexanes, and D235-02 (Reapproved 2007), Standard Specification for Mineral Spirits (Petroleum Spirits) (Hydrocarbon Dry Cleaning Solvent), respectively. Naphthas to be blended or marketed as motor gasoline or aviation gasoline, or that are to be used as petrochemical and synthetic natural gas (SNG) feedstocks are excluded.

Spent liquor solids means the dry weight of the solids in the spent pulping liquor that enters the chemical recovery furnace or chemical recovery combustion unit.

Spent pulping liquor means the residual liquid collected from on-site pulping operations at chemical pulp

facilities that is subsequently fired in chemical recovery furnaces at kraft and soda pulp facilities or chemical recovery combustion units at sulfite or semi-chemical pulp facilities.

Standard conditions or standard temperature and pressure (STP) means 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

Steam reforming means a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water.

Still gas means any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, and propylene.

Storage tank means a vessel (excluding sumps) that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Sulfur recovery plant means all process units which recover sulfur or produce sulfuric acid from hydrogen

sulfide (H₂S) and/or sulfur dioxide (SO₂) from a common source of sour gas at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery units are a single sulfur recovery plant only when the units share the same source of sour gas. Sulfur recovery units that receive source gas from completely segregated sour gas treatment systems are separate sulfur recovery plants.

Supplemental fuel means a fuel burned within a petrochemical process that is not produced within the process itself.

Supplier means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

Taconite iron ore processing means an industrial process that separates and concentrates iron ore from taconite, a low grade iron ore, and heats the taconite in an indurating furnace to produce taconite pellets that are

used as the primary feed material for the production of iron in blast furnaces at integrated iron and steel plants.

TAME means tertiary amyl methyl ether,
(CH₃)₂(C₂H₅)COCH₃).

Trace concentrations means concentrations of less than 0.1 percent by mass of the process stream.

Transform means to use and entirely consume (except for trace concentrations) nitrous oxide or fluorinated GHGs in the manufacturing of other chemicals for commercial purposes. Transformation does not include burning of nitrous oxide.

Transshipment means the continuous shipment of nitrous oxide or a fluorinated GHG from a foreign state of origin through the United States or its territories to a second foreign state of final destination, as long as the shipment does not enter into United States jurisdiction. A transshipment, as it moves through the United States or its territories, cannot be re-packaged, sorted or otherwise changed in condition.

Trona means the raw material (mineral) used to manufacture soda ash; hydrated sodium bicarbonate carbonate (e.g. Na₂CO₃.NaHCO₃.2H₂O).

Ultimate analysis means the determination of the percentages of carbon, hydrogen, nitrogen, sulfur, and

chlorine and (by difference) oxygen in the gaseous products and ash after the complete combustion of a sample of an organic material.

Unfinished oils are all oils requiring further processing, except those requiring only mechanical blending.

United States means the 50 states, the District of Columbia, and U.S. possessions and territories.

Unstabilized crude oil means, for the purposes of this part, crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

Valve means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

Vegetable Oil means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

Volatile solids are the organic material in livestock manure and consist of both biodegradable and non-biodegradable fractions.

Waelz kiln means an inclined rotary kiln in which zinc-containing materials are charged together with a carbon reducing agent (e.g., petroleum coke, metallurgical coke, or anthracite coal).

Waxes means a solid or semi-solid material at 77 °F consisting of a mixture of hydrocarbons obtained or derived from petroleum fractions, or through a Fischer-Tropsch type process, in which the straight chained paraffin series predominates. This includes all marketable wax, whether crude or refined, with a congealing point between 80 (or 85) and 240 °F and a maximum oil content of 50 weight percent.

Wool fiberglass means fibrous glass of random texture, including fiberglass insulation, and other products listed in NAICS 327993.

You means an owner or operator subject to Part 98.

Zinc smelters means a facility engaged in the production of zinc metal, zinc oxide, or zinc alloy products from zinc sulfide ore concentrates, zinc calcine, or zinc-bearing scrap and recycled materials through the use of pyrometallurgical techniques involving the reduction and volatilization of zinc-bearing feed materials charged to a furnace.

§98.7 What standardized methods are incorporated by reference into this part?

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they exist on the date of approval, and a notice of any change in the materials will be published in the Federal Register. The materials are available for purchase at the corresponding address in this section. The materials are available for inspection at the EPA Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW, Washington, DC, phone (202) 566-1744 and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030, or go to: http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.

(a) The following material is available for purchase from the Association of Fertilizer and Phosphate Chemists (AFPC), P. O. Box 1645, Bartow, Florida 33831, <http://afpc.net>.

(1) Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 - Version 1.9, incorporation by reference (IBR) approved for §98.264(a) and §98.264(b).

(b) The following material is available for purchase from the American Gas Association (AGA), 400 North Capitol Street, N.W., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>.

(1) AGA Report No. 3 Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations & Uncertainty Guidelines (1990), incorporation by reference (IBR) approved for §98.34(b) and §98.244(b).

(2) AGA Report No. 3 Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 2: Specification and Installation Requirements (2000), IBR approved for §98.34(b) and §98.244(b).

(3) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for §98.244(b) and §98.254(c).

(4) AGA Transmission Measurement Committee Report No. 7 Measurement of Natural Gas by Turbine Meter (2006)/February, IBR approved for §98.34(b) and §98.244(b).

(c) The following material is available for purchase from the ASM International, 9639 Kinsman Road, Materials

Park, OH 44073, (440) 338-5151,
<http://www.asminternational.org>.

(1) ASM CS-104 UNS No. G10460 - Alloy Digest April 1985 (Carbon Steel of Medium Carbon Content), incorporation by reference (IBR) approved for §98.174(b).

(d) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>.

(1) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, incorporation by reference (IBR) approved for §98.34(b), §98.244(b), §98.254(c), §98.344(c), and §98.364(e).

(2) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters, IBR approved for §98.34(b), §98.244(b), §98.254(c), §98.344(c), and §98.364(e).

(3) ASME MFC-5M-1985 (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for §98.34(b) and §98.244(b).

(4) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for §98.34(b), §98.244(b), §98.254(c), §98.344(c), and §98.364(e).

(5) ASME MFC-7M-1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for §98.34(b), §98.244(b), §98.254(c), §98.344(c), and §98.364(e).

(6) ASME MFC-9M-1988 (Reaffirmed 2001) Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for §98.34(b) and §98.244(b).

(7) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for §98.244(b), §98.254(c), and §98.344(c).

(8) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for §98.244(b), §98.254(c), §98.344(c), and §98.364(e).

(9) ASME MFC-16-2007 Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for §98.244(b).

(10) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters, IBR approved for §98.244(b), §98.254(c), §98.344(c), and §98.364(e).

(11) ASME MFC-22-2007 Measurement of Liquid by Turbine Flowmeters, IBR approved for §98.244(b).

(e) The following material is available for purchase from the American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken,

Pennsylvania 19428-B2959, (800) 262-1373,

<http://www.astm.org>.

(1) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime, incorporation by reference (IBR) approved for §98.114(b), §98.174(b), §98.184(b), §98.194(c), and §98.334(b).

(2) ASTM C114-09 Standard Test Methods for Chemical Analysis of Hydraulic Cement, IBR approved for §98.84(a), §98.84(b), and §98.84(c).

(3) ASTM D235-02 (Reapproved 2007) Standard Specification for Mineral Spirits (Petroleum Spirits) (Hydrocarbon Dry Cleaning Solvent), IBR approved for §98.6.

(4) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §98.34(a) and §98.254(e).

(5) ASTM D388-05 Standard Classification of Coals by Rank, IBR approved for §98.6.

(6) ASTM D910-07a Standard Specification for Aviation Gasolines, IBR approved for §98.6.

(7) ASTM D1298-99 (Reapproved 2005) Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, IBR approved for §98.33(a).

(8) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §98.34(a) and §98.254(e).

(9) ASTM D1836-07 Standard Specification for Commercial Hexanes, IBR approved for §98.6.

(10) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §98.34(b), §98.74(c), §98.164(b), §98.244(b), §98.254(d), and §98.344(b).

(11) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §98.34(b), §98.74(c), §98.164(b), §98.254(d), §98.344(b), and §98.364(c).

(12) ASTM D2013-07 Standard Practice for Preparing Coal Samples for Analysis, IBR approved for §98.164(b).

(13) ASTM D2234/D2234M-07 Standard Practice for Collection of a Gross Sample of Coal, IBR approved for §98.164(b).

(14) ASTM D2502-04 Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements, IBR approved for §98.34(b) and §98.74(c).

(15) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, IBR approved for §98.34(b) and §98.74(c).

(16) ASTM D2505-88 (Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography, IBR approved for §98.244(b).

(17) ASTM D2597-94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for §98.164(b).

(18) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke, IBR approved for §98.74(c), §98.164(b), §98.244(b), §98.254(i), §98.284(c), §98.284(d), §98.314(c), §98.314(d), and §98.314(f).

(19) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method, IBR approved for §98.34(b), §98.74(c), and §98.164(b).

(20) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility

Factor, and Relative Density of Gaseous Fuels, IBR approved for §98.34(a) and §98.254(e).

(21) ASTM D3682-01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes, IBR approved for §98.144(b).

(22) ASTM D4057-06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for §98.164(b).

(23) ASTM D4177-95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for §98.164(b).

(24) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §98.34(a) and §98.254(e).

(25) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for §98.34(a) and §98.254(e).

(26) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, IBR

approved for §98.34(b), §98.74(c), §98.164(b), §98.244(b), §98.254(i).

(27) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal, IBR approved for §98.34(b), §98.74(c), §98.114(b), §98.164(b), §98.174(b), §98.184(b), §98.244(b), §98.254(i), §98.274(b), §98.284(c), §98.284(d), §98.314(c), §98.314(d), §98.314(f), and §98.334(b).

(28) ASTM D5865-07a Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §98.34(a).

(29) ASTM D6060-96 (Reapproved 2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph, IBR approved for §98.244(b).

(30) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for §98.54(b) and §98.224(b).

(31) ASTM D6609-08 Standard Guide for Part-Stream Sampling of Coal, IBR approved for §98.164(b).

(32) ASTM D6751-08 Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, IBR approved for §98.6.

(33) ASTM D6866-08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, IBR approved for §98.33(e), §98.34(d), §98.34(e), and §98.36(e).

(34) ASTM D6883-04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, IBR approved for §98.164(b).

(35) ASTM D7430-08a¹ Standard Practice for Mechanical Sampling of Coal, IBR approved for §98.164(b).

(36) ASTM D7459-08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources, IBR approved for §98.33(e), §98.34(d), §98.34(e), and §98.36(e).

(37) ASTM E359-00 (Reapproved 2005)¹ Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate), IBR approved for §98.294(a) and §98.294(b).

(38) ASTM E1019-08 Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various

Combustion and Fusion Techniques, IBR approved for §98.174(b).

(39) ASTM E1747-95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications, IBR approved for 98.424(b).

(40) ASTM E1915-07a Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry, IBR approved for §98.174(b).

(41) ASTM E1941-04 Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys, IBR approved for §98.114(b), §98.184(b), §98.334(b).

(42) ASTM UOP539-97 Refinery Gas Analysis by Gas Chromatography, IBR approved for §98.164(b), §98.244(b), and §98.254(d), and §98.344(b).

(f) The following material is available for purchase from the Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143, (918) 493-3872, <http://www.gasprocessors.com>.

(1) GPA 2172-09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer, IBR approved for §98.34(a).

(2) GPA 2261-00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, IBR approved for §98.34(a), §98.164(b), §98.254(d), and §98.344(b).

(g) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>.

(1) ISO 3170: Petroleum liquids—Manual sampling - Third Edition 2004-02-01, IBR approved for §98.164(b).

(2) ISO 3171: Petroleum Liquids—Automatic pipeline sampling - Second Edition 1988-12-01, IBR approved for §98.164(b).

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits— Method by Collection of the Liquid in a Volumetric Tank (1987-10-01) - First Edition, IBR approved for §98.244(b).

(4) ISO/TR 15349-1: 1998, Unalloyed steel— Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998-10-15) - First Edition, IBR approved for §98.174(b).

(5) ISO/TR 15349-3: 1998, Unalloyed steel— Determination of low carbon content. Part 3: Infrared

absorption method after combustion in an electric resistance furnace (with preheating) (1998-10-15) - First Edition, IBR approved for §98.174(b).

(h) The following material is available for purchase from the National Lime Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243-5463, <http://www.lime.org>.

(1) CO₂ Emissions Calculation Protocol for the Lime Industry-English Units Version, February 5, 2008 Revision-National Lime Association, incorporation by reference (IBR) approved for §98.194(c) and §98.194(e).

(i) The following material is available for purchase from the National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899-1070, (800) 877-8339, <http://www.nist.gov/index.html>.

(1) Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009), incorporation by reference (IBR) approved for §98.244(b), §98.254(h), and §98.344(a).

(j) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332-8686, <http://www.tappi.org>.

(1) T650 om-05 Solids Content of Black Liquor, TAPPI, incorporation by reference (IBR) approved for §98.276(c) and §98.277(d).

(2) T684 om-06 Gross Heating Value of Black Liquor, TAPPI, incorporation by reference (IBR) approved for §98.274(b).

§98.8 What are the compliance and enforcement provisions of this part?

Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. §7414). A violation includes but is not limited to failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emissions, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.

§98.9 Addresses.

All requests, notifications, and communications to the Administrator pursuant to this part, other than submittal of the annual GHG report, shall be submitted to the following address:

(a) For U.S. mail.

Director, Climate Change Division

1200 Pennsylvania Ave., NW

Mail Code: 6207J

Washington, DC 20460

(b) For package deliveries.

Director, Climate Change Division

1310 L St, NW

Washington, DC 20005

Table A-1 of Subpart A-Global Warming Potentials (100-Year Time Horizon)

Name	CAS #	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124-38-9	CO ₂	1
Methane	74-82-8	CH ₄	21
Nitrous oxide	10024-97-2	N ₂ O	310
HFC-23	75-46-7	CHF ₃	11,700
HFC-32	75-10-5	CH ₂ F ₂	650
HFC-41	593-53-3	CH ₃ F	150
HFC-125	354-33-6	C ₂ HF ₅	2,800
HFC-134	359-35-3	C ₂ H ₂ F ₄	1,000
HFC-134a	811-97-2	CH ₂ FCF ₃	1,300
HFC-143	430-66-0	C ₂ H ₃ F ₃	300
HFC-143a	420-46-2	C ₂ H ₃ F ₃	3,800
HFC-152	624-72-6	CH ₂ FCH ₂ F	53
HFC-152a	75-37-6	CH ₃ CHF ₂	140
HFC-161	353-36-6	CH ₃ CH ₂ F	12
HFC-227ea	431-89-0	C ₃ HF ₇	2,900
HFC-236cb	677-56-5	CH ₂ FCF ₂ CF ₃	1,340
HFC-236ea	431-63-0	CHF ₂ CHF ₂ CF ₃	1,370
HFC-236fa	690-39-1	C ₃ H ₂ F ₆	6,300
HFC-245ca	679-86-7	C ₃ H ₃ F ₅	560
HFC-245fa	460-73-1	CHF ₂ CH ₂ CF ₃	1,030
HFC-365mfc	406-58-6	CH ₃ CF ₂ CH ₂ CF ₃	794
HFC-43-10mee	138495-42-8	CF ₃ CFHCFHCF ₂ CF ₃	1,300
Sulfur hexafluoride	2551-62-4	SF ₆	23,900
Trifluoromethyl sulphur pentafluoride	373-80-8	SF ₅ CF ₃	17,700
Nitrogen trifluoride	7783-54-2	NF ₃	17,200

Table A-1 of Subpart A—Global Warming Potentials (100-Year Time Horizon)

Name	CAS #	Chemical formula	Global warming potential (100 yr.)
PFC-14 (Perfluoromethane)	75-73-0	CF ₄	6,500
PFC-116 (Perfluoroethane)	76-16-4	C ₂ F ₆	9,200
PFC-218 (Perfluoropropane)	76-19-7	C ₃ F ₈	7,000
Perfluorocyclopropane	931-91-9	c-C ₃ F ₆	17,340
PFC-3-1-10 (Perfluorobutane)	355-25-9	C ₄ F ₁₀	7,000
Perfluorocyclobutane	115-25-3	c-C ₄ F ₈	8,700
PFC-4-1-12 (Perfluoropentane)	678-26-2	C ₅ F ₁₂	7,500
PFC-5-1-14 (Perfluorohexane)	355-42-0	C ₆ F ₁₄	7,400
PFC-9-1-18	306-94-5	C ₁₀ F ₁₈	7,500
HCFE-235da2 (Isoflurane)	26675-46-7	CHF ₂ OCHClCF ₃	350
HFE-43-10pccc (H-Galden 1040x)	E1730133	CHF ₂ OCF ₂ OC ₂ F ₄ OCHF ₂	1,870
HFE-125	3822-68-2	CHF ₂ OCF ₃	14,900
HFE-134	1691-17-4	CHF ₂ OCHF ₂	6,320
HFE-143a	421-14-7	CH ₃ OCF ₃	756
HFE-227ea	2356-62-9	CF ₃ CHFOCF ₃	1,540
HFE-236ca12 (HG-10)	78522-47-1	CHF ₂ OCF ₂ OCHF ₂	2,800
HFE-236ea2 (Desflurane)	57041-67-5	CHF ₂ OCHF ₂ CF ₃	989
HFE-236fa	20193-67-3	CF ₃ CH ₂ OCF ₃	487
HFE-245cb2	22410-44-2	CH ₃ OCF ₂ CF ₃	708
HFE-245fa1	84011-15-4	CHF ₂ CH ₂ OCF ₃	286
HFE-245fa2	1885-48-9	CHF ₂ OCH ₂ CF ₃	659
HFE-254cb2	425-88-7	CH ₃ OCF ₂ CHF ₂	359
HFE-263fb2	460-43-5	CF ₃ CH ₂ OCH ₃	11
HFE-329mcc2	67490-36-2	CF ₃ CF ₂ OCF ₂ CHF ₂	919
HFE-338mcf2	156053-88-2	CF ₃ CF ₂ OCH ₂ CF ₃	552
HFE-338pcc13 (HG-01)	188690-78-0	CHF ₂ OCF ₂ CF ₂ OCHF ₂	1,500
HFE-347mcc3	28523-86-6	CH ₃ OCF ₂ CF ₂ CF ₃	575
HFE-347mcf2	E1730135	CF ₃ CF ₂ OCH ₂ CHF ₂	374
HFE-347pcf2	406-78-0	CHF ₂ CF ₂ OCH ₂ CF ₃	580
HFE-356mec3	382-34-3	CH ₃ OCF ₂ CHF ₂ CF ₃	101
HFE-356pcc3	160620-20-2	CH ₃ OCF ₂ CF ₂ CHF ₂	110
HFE-356pcf2	E1730137	CHF ₂ CH ₂ OCF ₂ CHF ₂	265
HFE-356pcf3	35042-99-0	CHF ₂ OCH ₂ CF ₂ CHF ₂	502
HFE-365mcf3	378-16-5	CF ₃ CF ₂ CH ₂ OCH ₃	11
HFE-374pc2	512-51-6	CH ₃ CH ₂ OCF ₂ CHF ₂	557

Table A-1 of Subpart A—Global Warming Potentials (100-Year Time Horizon)

Name	CAS #	Chemical formula	Global warming potential (100 yr.)
HFE-449s1 (HFE-7100) Chemical blend	163702-07-6 163702-08-7	C ₄ F ₉ OCH ₃ (CF ₃) ₂ CF ₂ OCF ₂ CH ₃	297
HFE-569sf2 (HFE-7200) Chemical blend	163702-05-4 163702-06-5	C ₄ F ₉ OC ₂ H ₅ (CF ₃) ₂ CF ₂ OC ₂ H ₅	59
Sevoflurane	28523-86-6	CH ₂ FOCH (CF ₃) ₂	345
HFE-356mm1	13171-18-1	(CF ₃) ₂ CHOCH ₃	27
HFE-338mmz1	26103-08-2	CHF ₂ OCH (CF ₃) ₂	380
(Octafluorotetramethylene)hydroxymethyl group	NA	X-(CF ₂) ₄ CH(OH)-X	73
HFE-347mmyl1	22052-84-2	CH ₃ OCF (CF ₃) ₂	343
Bis(trifluoromethyl)-methanol	920-66-1	(CF ₃) ₂ CHOH	195
2,2,3,3,3-pentafluoropropanol	422-05-9	CF ₃ CF ₂ CH ₂ OH	42
PFPME	NA	CF ₃ OCF (CF ₃) CF ₂ OCF ₂ OCF ₃	10,300

NA = not available

Table A-2 of Subpart A—Units of Measure Conversions.

To convert from	To	Multiply by
Kilograms (kg)	Pounds (lbs)	2.20462
Pounds (lbs)	Kilograms (kg)	0.45359
Pounds (lbs)	Metric tons	4.53592 x 10 ⁻⁴
Short tons	Pounds (lbs)	2,000
Short tons	Metric tons	0.90718
Metric tons	Short tons	1.10231
Metric tons	Kilograms (kg)	1,000
Cubic meters (m ³)	Cubic feet (ft ³)	35.31467
Cubic feet (ft ³)	Cubic meters (m ³)	0.028317
Gallons (liquid, US)	Liters (l)	3.78541
Liters (l)	Gallons (liquid, US)	0.26417
Barrels of Liquid Fuel (bbl)	Cubic meters (m ³)	0.15891
Cubic meters (m ³)	Barrels of Liquid Fuel (bbl)	6.289
Barrels of Liquid Fuel (bbl)	Gallons (liquid, US)	42
Gallons (liquid, US)	Barrels of Liquid Fuel (bbl)	0.023810
Gallons (liquid, US)	Cubic meters (m ³)	0.0037854
Liters (l)	Cubic meters (m ³)	0.001
Feet (ft)	Meters (m)	0.3048
Meters (m)	Feet (ft)	3.28084

To convert from	To	Multiply by
Miles (mi)	Kilometers (km)	1.60934
Kilometers (km)	Miles (mi)	0.62137
Square feet (ft ²)	Acres	2.29568×10^{-5}
Square meters (m ²)	Acres	2.47105×10^{-4}
Square miles (mi ²)	Square kilometers (km ²)	2.58999
Degrees Celsius (°C)	Degrees Fahrenheit (°F)	$^{\circ}\text{C} = (5/9) \times (^{\circ}\text{F} - 32)$
Degrees Fahrenheit (°F)	Degrees Celsius (°C)	$^{\circ}\text{F} = (9/5) \times ^{\circ}\text{C} + 32$
Degrees Celsius (°C)	Kelvin (K)	$\text{K} = ^{\circ}\text{C} + 273.15$
Kelvin (K)	Degrees Rankine (°R)	1.8
Joules	Btu	9.47817×10^{-4}
Btu	MMBtu	1×10^{-6}
Pascals (Pa)	Inches of Mercury (in Hg)	2.95334×10^{-4}
Inches of Mercury (inHg)	Pounds per square inch (psi)	0.49110
Pounds per square inch (psi)	Inches of Mercury (in Hg)	2.03625

Subpart B [RESERVED]

Subpart C—General Stationary Fuel Combustion Sources

§98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include:

- (1) Portable equipment, as defined in §98.6.
 - (2) Emergency generators and emergency equipment, as defined in §98.6.
 - (3) Irrigation pumps at agricultural operations.
 - (4) Flares, unless otherwise required by provisions of another subpart of 40 CFR part 98 to use methodologies in this subpart.
 - (5) Electricity generating units that are subject to subpart D of this part.
- (c) For a unit that combusts hazardous waste (as defined in 40 CFR 261.3), reporting of GHG emissions is not required unless either of the following conditions apply:
- (1) Continuous emission monitors (CEMS) are used to quantify CO₂ mass emissions.
 - (2) Any fuel listed in Table C-1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C-1 of this subpart.

§98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary fuel combustion sources and the facility meets the applicability requirements of either §§98.2(a)(1), 98.2(a)(2), or 98.2(a)(3).

§98.32 GHGs to report.

You must report CO₂, CH₄, and N₂O mass emissions from each stationary fuel combustion unit.

§98.33 Calculating GHG emissions.

You must calculate CO₂ emissions according to paragraph (a) of this section, and calculate CH₄ and N₂O emissions according to paragraph (c) of this section.

(a) CO₂ emissions from fuel combustion. Calculate CO₂ emissions by using one of the four calculation methodologies in this paragraph (a) subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section. If you co-fire biomass fuels with fossil fuels, report CO₂ emissions from the combustion of biomass separately using the methods in paragraph (e) of this section.

(1) Tier 1 Calculation Methodology. Calculate the annual CO₂ mass emissions for each type of fuel by using Equation C-1 of this section.

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF \quad (\text{Eq. C-1})$$

Where:

CO₂ = Annual CO₂ mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).

EF = Fuel-specific default CO₂ emission factor, from Table C-1 of this subpart (kg CO₂/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) Tier 2 Calculation Methodology. Calculate the annual CO₂ mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.

(i) Equation C-2a of this section applies to any type of fuel listed in Table C-1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C-2c of this section.

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF \quad (\text{Eq. C-2a})$$

Where:

CO₂ = Annual CO₂ mass emissions for a specific fuel type (metric tons).

Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Annual average high heat value of the fuel from all valid samples for the year (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

EF = Fuel-specific default CO₂ emission factor, from Table C-1 of this subpart (kg CO₂/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) The minimum number of HHV samples for determining annual average HHV is specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34. The method for computing the annual average HHV is a function of how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a) (2) (ii) (A) or (a) (2) (ii) (B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then 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.

$$(HHV)_{annual} = \frac{\sum_{i=1}^n (HHV)_i * (Fuel)_i}{\sum_{i=1}^n (Fuel)_i} \quad (\text{Eq. C-2b})$$

Where:

- (HHV)_{annual} = Weighted annual average high heat value of the fuel (mmBtu per mass or volume).
- (HHV)_i = High heat value of the fuel, for month "i" (mmBtu per mass or volume).
- (Fuel)_i = Mass or volume of the fuel combusted during month "i" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
- n = Number of months in the year that fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, then 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).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C-2c of this section. Equation C-2c of this section may also be used for any other solid fuel listed in Table C-1 of this subpart provided that steam is generated by the unit.

$$\text{CO}_2 = 1 \times 10^{-3} \text{ Steam} * \text{B} * \text{EF} \quad (\text{Eq. C-2c})$$

Where:

- CO₂ = Annual CO₂ mass emissions from MSW or solid fuel combustion (metric tons).
- Steam = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).
- B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
- EF = Fuel-specific default CO₂ emission factor, from Table C-1 of this subpart (kg CO₂/mmBtu).
- 1 x 10⁻³ = Conversion factor from kilograms to metric tons.

(3) Tier 3 Calculation Methodology. Calculate the annual CO₂ mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C-3 of this section.

$$\text{CO}_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.91 \quad (\text{Eq. C-3})$$

Where:

CO₂ = Annual CO₂ mass emissions from the combustion of the specific solid fuel (metric tons).

Fuel = Annual mass of the solid fuel combusted, from company records as defined in §98.6 (short tons).

CC = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a) (2) (ii) of this section.

44/12 = Ratio of molecular weights, CO₂ to carbon.

0.91 = Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C-4 of this section.

$$\text{CO}_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.001 \quad (\text{Eq. C-4})$$

Where:

CO₂ = Annual CO₂ mass emissions from the combustion of the specific liquid fuel (metric tons).

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined

using the same procedures as specified for HHV in paragraph (a) (2) (ii) of this section.

44/12 = Ratio of molecular weights, CO₂ to carbon.

0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C-5 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \quad (\text{Eq. C-5})$$

Where:

CO₂ = Annual CO₂ mass emissions from combustion of the specific gaseous fuel (metric tons).

Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a) (2) (ii) of this section.

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a) (2) (ii) of this section.

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions, as defined in §98.6).

44/12 = Ratio of molecular weights, CO₂ to carbon.

0.001 = Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency

as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method" (incorporated by reference, see §98.7).

(v) The following default density values may be used for fuel oil, in lieu of using the ASTM method in paragraph (a) (3) (iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) Tier 4 Calculation Methodology. Calculate the annual CO₂ mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO₂ concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a) (4) (iv) of this section. Hourly measurements of CO₂ concentration and stack gas flow rate are converted to CO₂ mass emission rates in metric tons per hour.

(ii) When the CO₂ concentration is measured on a wet basis, Equation C-6 of this section is used to calculate the hourly CO₂ emission rates:

$$CO_2 = 5.18 \times 10^{-7} * C_{CO_2} * Q \quad (\text{Eq. C-6})$$

Where:

CO₂ = CO₂ mass emission rate (metric tons/hr).
 C_{CO2} = Hourly average CO₂ concentration (% CO₂).
 Q = Hourly average stack gas volumetric flow rate (scfh).
 5.18 x 10⁻⁷ = Conversion factor (metric tons/scf/% CO₂).

(iii) If the CO₂ concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content as described in §75.11(b) (2) of this chapter or, for certain types of fuel, use a default moisture percentage from §75.11(b) (1) of this chapter. For each unit operating hour, a moisture correction must be applied to Equation C-6 of this section as follows:

$$CO_2^* = CO_2 \left(\frac{100 - \%H_2O}{100} \right) \quad (\text{Eq. C-7})$$

Where:

CO₂^{*} = Hourly CO₂ mass emission rate, corrected for moisture (metric tons/hr).
 CO₂ = Hourly CO₂ mass emission rate from Equation C-6 of this section, uncorrected (metric tons/hr).
 %H₂O = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O₂) concentration monitor may be used in lieu of a CO₂ concentration monitor to determine the hourly CO₂ concentrations, in accordance with Equation F-14a or F-14b (as applicable) in appendix F to 40 CFR part 75, if the effluent gas stream monitored by the CEMS consists

solely of combustion products (i.e., no process CO₂ emissions are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 are combusted in the unit. If the O₂ monitoring option is selected, the F-factors used in Equations F-14a and F-14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to 40 CFR part 75, as applicable. If Equation F-14b is used, the hourly moisture percentage in the stack gas shall be either a measured value in accordance with §75.11(b)(2) of this chapter, or, for certain types of fuel, a default moisture value from §75.11(b)(1) of this chapter.

(v) Each hourly CO₂ mass emission rate from Equation C-6 or C-7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO₂ mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO₂ mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO₂ mass emissions separately, as described in paragraph (e) of this section.

(5) Alternative methods for units with continuous monitoring systems. Units not subject to the Acid Rain Program that report data to EPA according to 40 CFR part 75 may use the alternative methods in this paragraph in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to appendix D to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO₂ mass emissions data, calculate the annual CO₂ mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to 40 CFR part 75, together with Equation G-4 in appendix G to 40 CFR part 75 to determine the hourly CO₂ mass emission rates, in units of tons/hr;

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO₂ mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO₂ mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to 40 CFR 75.19 of this chapter but is not required by the applicable 40 CFR part 75 program to report CO₂ mass emissions data, calculate the annual CO₂ mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO₂ mass emissions, in units of short tons, using Equation LM-11 in 40 CFR 75.19(c) (4) (iii).

(B) Sum the hourly CO₂ mass emissions values over the entire reporting year to obtain the cumulative annual CO₂ mass emissions, in units of short tons.

(C) Divide the cumulative annual CO₂ mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to the Acid Rain Program, uses flow rate and CO₂ (or O₂) CEMS to report heat input data year-round according to 40 CFR part 75, but is

not required by the applicable 40 CFR part 75 program to report CO₂ mass emissions data, calculate the annual CO₂ mass emissions as follows:

(A) Use Equation F-11 or F-2 (as applicable) in appendix F to 40 CFR part 75 to calculate the hourly CO₂ mass emission rates from the CEMS data. If an O₂ monitor is used, convert the hourly average O₂ readings to CO₂ using Equation F-14a or F-14b in appendix F to 40 CFR part 75 (as applicable), before applying Equation F-11 or F-2.

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO₂ mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO₂ mass emissions value by 1.1 to convert it to metric tons.

(D) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO₂ mass emissions separately, as described in paragraph (e) of this section.

(b) Use of the four tiers. Use of the four tiers of CO₂ emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C-1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less.

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C-1 of this subpart.

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receives 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.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less provided that the fuel is listed in Table C-1 of this subpart.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of pipeline quality natural gas and distillate fuel oil.

(iii) May be used for MSW in a unit of any size that produces steam, if the use of Tier 4 is not required.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size that combusts any type of fuel listed in Table C-1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C-1 of this subpart (except MSW), unless either of the following conditions apply:

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b) (1) (iii) and (b) (2) (ii) of this section.

(B) The use of Tier 4 is required.

(iii) Shall be used 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 provided that both of the following conditions apply:

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

(B) The fuel provides 10% or more of the annual heat input to the unit or, if §98.36(c) (3) applies, to a group of units served by common supply pipe.

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b) (4) (ii) (A) through (b) (4) (ii) (F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR part 75, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal

or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO₂ concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b) (4) (ii) (B) through (b) (4) (ii) (D) of this section.

(C) The CO₂ and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b) (4) (ii) (E) and (b) (4) (ii) (F) of this section.

(5) The Tier 4 Calculation Methodology shall be used beginning on:

(i) January 1, 2010, for a unit that is required to report CO₂ mass emissions beginning on that date, if all of the monitors needed to measure CO₂ mass emissions have been installed and certified by that date.

(ii) January 1, 2011, for a unit that is required to report CO₂ mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO₂ mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010.

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5) of this section, CO₂ emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) Calculation of CH₄ and N₂O emissions from stationary combustion sources. You must calculate annual CH₄ and N₂O mass emissions only for units that are required to report CO₂ emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C-2 of this subpart.

(1) Use Equation C-8 of this section to estimate CH₄ and N₂O emissions for any fuels for which you use the Tier 1

or Tier 3 calculation methodologies for CO₂. Use the same values for fuel combustion that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * Fuel * HHV * EF \quad (\text{Eq. C-8})$$

Where:

- CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a particular type of fuel (metric tons).
- Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).
- HHV = Default high heat value of the fuel from Table C-1 of this subpart (mmBtu per mass or volume).
- EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).
- 1 x 10⁻³ = Conversion factor from kilograms to metric tons.

(2) Use Equation C-9a of this section to estimate CH₄ and N₂O emissions for any fuels for which you use the Tier 2 Equation C-2a of this section to estimate CO₂ emissions. Use the same values for fuel combustion and HHV that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * HHV * EF * Fuel \quad (\text{Eq. C-9a})$$

Where:

- CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a particular type of fuel (metric tons).

- Fuel = Mass or volume of the fuel combusted during the reporting year.
- HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).
- EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).
- 1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) Use Equation C-9b of this section to estimate CH₄ and N₂O emissions for any fuels for which you use Equation C-2c of this section to calculate the CO₂ emissions. Use the same values for steam generation and the ratio "B" that you use for Equation C-2c.

$$\text{CH}_4 \text{ or N}_2\text{O} = 1 \times 10^{-3} \text{ Steam} * \text{B} * \text{EF} \quad (\text{Eq. C-9b})$$

Where:

- CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a solid fuel (metric tons).
- Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).
- B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).
- EF = Fuel-specific emission factor for CH₄ or N₂O, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).
- 1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) Use Equation C-10 of this section for units in the Acid Rain Program, units that monitor and report heat input on a year-round basis according to 40 CFR part 75, and units that use the Tier 4 Calculation Methodology.

$$\text{CH}_4 \text{ or N}_2\text{O} = 0.001 * (\text{HI})_A * \text{EF} \quad (\text{Eq. C-10})$$

Where:

- $\text{CH}_4 \text{ or N}_2\text{O}$ = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
- $(\text{HI})_A$ = Cumulative annual heat input from the fuel, derived from the electronic data reports required under §75.64 of this chapter or, for Tier 4 units, from the best available information as described in paragraph (c) (4) (ii) of this section (mmBtu).
- EF = Fuel-specific emission factor for CH_4 or N_2O , from Table C-2 of this section (kg CH_4 or N_2O per mmBtu).
- 0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH_4 or N_2O emissions.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, use Equation C-10 of this section separately for each type of fuel. If flow rate and diluent gas monitors are used to measure the unit heat input, use the best available

information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the annual heat input from each type of fuel.

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

(d) Calculation of CO₂ from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation C-11 of this section to calculate the CO₂ emissions from the sorbent, if those CO₂ emissions are not monitored by CEMS:

$$CO_2 = 0.91 * S * R * \left(\frac{MW_{CO_2}}{MW_S} \right) \quad (\text{Eq. C-11})$$

Where:

CO₂ = CO₂ emitted from sorbent for the reporting year (metric tons).

S = Limestone or other sorbent used in the reporting year, from company records (short tons).

R = 1.00, the calcium-to-sulfur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_S = Molecular weight of sorbent (100 if calcium carbonate).

0.91 = Conversion factor from short tons to metric tons

(2) The annual CO₂ mass emissions for the unit shall be the sum of the CO₂ emissions from the combustion process and the CO₂ emissions from the sorbent.

(e) CO₂ emissions from combustion of biomass. Use the procedures of this paragraph (e) to estimate biogenic CO₂ emissions from units that combust a combination of biomass and fossil fuels. Reporting of CO₂ emissions from combustion of biomass is required only for those biomass fuels listed in Table C-1 of this section, unless emissions are measured using CEMS.

(1) If CEMS are not used to measure CO₂, use Equation C-1 of this subpart to calculate the annual CO₂ mass emissions from the combustion of biomass (except MSW) for a unit of any size. Determine the mass of biomass combusted using one of the following procedures in this paragraph (e) (1), as appropriate.

(i) Use company records.

(ii) Follow the procedures in paragraph (e) (5) of this section.

(iii) For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass

fuels and document the procedure used in the GHG Monitoring Plan required by §98.3(g)(5).

(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, 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. If MSW is combusted in the unit, follow the procedures in paragraph (e)(3) of this section.

(i) For each operating hour, use Equation C-12 of this section to determine the volume of CO₂ emitted.

$$V_{CO_2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \quad (\text{Eq. C-12})$$

Where:

V_{CO_2h} = Hourly volume of CO₂ emitted (scf).

$(\%CO_2)_h$ = Hourly average CO₂ concentration, measured by the CO₂ concentration monitor, or, if applicable, calculated from the hourly average O₂ concentration (%CO₂).

Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).

t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel,

i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).

100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO_2h} values for the reporting year, to obtain V_{total} , the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C-13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C-13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{\text{Fuel} * F_c * \text{HHV}}{10^6} \quad (\text{Eq. C-13})$$

Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in §98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 or a site-specific value determined under section 3.3.6 of appendix F to 40 CFR part 75 (scf CO_2 /mmBtu).

HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio} , the annual volume of CO_2 from the combustion of biomass. If a CEMS is being used to measure the combined combustion and process emissions from a unit that is subject to another subpart of part 98, then also subtract CO_2 process emissions from V_{total} to determine V_{bio} . The CO_2 process emissions must be calculated according to the requirements of the applicable subpart.

(v) Calculate the biogenic percentage of the annual CO_2 emissions, expressed as a decimal fraction, using Equation C-14 of this section:

$$\% \text{ Biogenic} = \frac{V_{bio}}{V_{total}} \quad (\text{Eq. C-14})$$

(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the results obtained from Equation C-14 of this section by the annual CO_2 mass emissions in metric tons, as determined:

(A) Under paragraph (a) (4) (vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a) (5) (iii) (B) of this section, for units using the alternative calculation methodology specified in paragraph (a) (5) (iii).

(C) From the electronic data report required under §75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO₂ mass emissions according to 40 CFR part 75. However, before calculating the annual biogenic CO₂ mass emissions, multiply the cumulative annual CO₂ mass emissions by 0.91 to convert from short tons to metric tons.

(3) For a unit that combusts MSW, the annual biogenic CO₂ emissions shall be calculated using the procedures in this paragraph (3).

(i) If the Tier 1 or Tier 2 Calculation Methodology is used to quantify CO₂ mass emissions:

(A) Use Equation C-1 or C-2c of this subpart, as appropriate, to calculate the annual CO₂ mass emissions from MSW combustion.

(B) Determine the relative proportions of biogenic and non-biogenic CO₂ emissions on a quarterly basis using the method specified in §98.34(d).

(C) Determine the annual biogenic CO₂ mass emissions from MSW combustion by multiplying the annual CO₂ mass emissions by the annual average biogenic decimal fraction obtained from §98.34(d).

(ii) If the unit uses Tier 4 to quantify CO₂ emissions:

(A) Follow the procedures in paragraphs (e) (2) (i) and (ii) of this section, to determine V_{total} .

(B) If any fossil fuel was combusted during the year, follow the procedures in paragraph (e) (2) (iii) of this section, to determine V_{ff} .

(C) Subtract V_{ff} from V_{total} , to obtain V_{MSW} , the annual volume of CO_2 emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO_2 emissions (V_{bio}) from MSW combustion as follows. Multiply the annual volume of CO_2 emissions from MSW combustion (V_{MSW}) by the annual average biogenic decimal fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(E) Calculate the biogenic percentage of the annual CO_2 emissions from the unit, using Equation C-14 of this section. For the purposes of this calculation, the term " V_{bio} " in the numerator of Equation C-14 of this section shall be the results of the calculation performed under paragraph (e) (3) (ii) (D) of this section.

(F) Calculate the annual biogenic CO_2 mass emissions according to paragraph (e) (2) (vi) (A) of this section.

(4) As an alternative to the procedures in paragraph (e) (2) of this section, use ASTM Methods D7459-08 and D6866-08 to determine the biogenic portion of the annual CO_2 emissions, as described in §98.34(e). If this option is

selected, the results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO₂ is biogenic), and the values shall be averaged over the reporting year. The annual biogenic CO₂ mass emissions shall be calculated by multiplying the the total annual CO₂ mass emissions by the annual average biogenic fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(5) If Equation C-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C-15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by §98.3(g) (5).

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{2000 (HHV)_{bio} (Eff)_{bio}} \quad (\text{Eq. C-15})$$

Where:

(Fuel)_p = Quantity of biomass consumed during the measurement period "p" (tons/year or tons/month, as applicable).

H = Average enthalpy of the boiler steam for the measurement period (Btu/lb).

S	=	Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).
(HI) _{nb}	=	Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).
(HHV) _{bio}	=	Default or measured high heat value of the biomass fuel (Btu/lb).
(Eff) _{bio}	=	Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.
2000	=	Conversion factor (lb/ton).

§98.34 Monitoring and QA/QC requirements.

The CO₂ mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel is specified in this paragraph. When the specified frequency is based on a specified time period (i.e., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required only for those periods in which the unit operates.

(i) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(iii) For liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(iv) For solid fuels other than coal and MSW, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(3) If different types of fuel (e.g., different ranks of coal or different grades of fuel oil) are blended prior to combustion, use one of the following procedures in this paragraph.

(i) Use a weighted HHV value in the emission calculations, based on the relative proportions of each fuel in the blend.

(ii) Take a representative sample of the blend and analyze it for HHV.

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraphs (a)(2) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specified in paragraphs (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with missing data procedures of §98.35.

(6) Use any applicable fuel sampling and analysis methods in this paragraph (a)(6) to determine the high heat values. Alternatively, for gaseous fuels, the HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).

(ii) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).

(iii) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).

(iv) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).

(v) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(vi) GPA Standard 2172-09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7).

(vii) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(viii) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).

(b) For the Tier 3 Calculation Methodology:

(1) Calibrate each oil and gas flow meter according to §98.3(i) and the provisions of paragraph (b).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i):

(A) An applicable flow meter test method listed in paragraphs (b)(4)(i) through (b)(4)(viii) of this section.

(B) The calibration procedures specified by the flow meter manufacturer.

(C) An industry-accepted or industry standard calibration practice.

(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.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in §98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of fuels is transported by a common pipe (e.g., still gas and supplementary natural gas), you must either separately meter each of the fuels prior to mixing using flow meters calibrated according to §98.3(i), or use flow meters calibrated according to §98.3(i) to measure the mixed fuel at the common pipe and to separately meter an appropriate subset of the fuels prior to mixing. If the latter option is chosen, quantify the fuels that are not measured prior to mixing by subtracting out the fuels measured prior to mixing from the fuel measured at the common pipe.

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based

standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in paragraph (b) (3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) At a minimum, fuel samples shall be collected at the frequency specified in this paragraph. When sampling is required at a specified time interval (e.g., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required for only those specified periods in which the unit operates.

(A) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(C) For other liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For solid fuels other than coal, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) 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.

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the minimum frequency specified in paragraph (b) (3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specified in paragraph (b) (3) of this section, appropriate substitute

data values shall be used in the emissions calculations, in accordance with the missing data procedures of §98.35.

(v) The procedures of paragraphs (a) (3) of this section apply to carbon content and molecular weight determinations.

(4) Use any applicable standard method from the following list to quality assure the data from each fuel flow meter.

(i) AGA Report No. 3, *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines* (1990) and Part 2: *Specification and Installation Requirements* (2000) (incorporated by reference, see §98.7).

(ii) AGA Transmission Measurement Committee Report No. 7, *Measurement of Gas by Turbine Meters* (2006) (incorporated by reference, see §98.7).

(iii) ASME MFC-3M-2004 *Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi* (incorporated by reference, see §98.7).

(iv) ASME MFC-4M-1986 (Reaffirmed 1997), *Measurement of Gas Flow by Turbine Meters* (incorporated by reference, see §98.7).

(v) ASME MFC-5M-1985 (Reaffirmed 1994), *Measurement of Liquid Flow in Closed Conduits Using Transit-Time*

Ultrasonic Flowmeters (incorporated by reference, see §98.7).

(vi) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(vii) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(viii) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, see §98.7).

(5) 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.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements (incorporated by reference, see §98.7).

(iv) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see §98.7).

(v) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(vi) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(vii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(c) For the Tier 4 Calculation Methodology, the CO₂ and flow rate monitors must be certified prior to the applicable deadline specified in §98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) §75.20(c)(2) and (4) and appendix A to 40 CFR part 75.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 (for the CO₂ concentration monitor) and Performance Specification 6 in appendix B to part 60 (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O₂ concentration monitor is used to determine CO₂ concentrations, the applicable provisions of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO₂ basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program. If appendix F to 40 CFR part 60 is selected for on-going quality assurance, perform

daily calibration drift assessments for both the CO₂ monitor (or surrogate O₂ monitor) and the flow rate monitor, conduct cylinder gas audits of the CO₂ concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the CO₂ concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to 40 CFR part 75 and the annual RATAs of the CERMS required by appendix F to 40 CFR part 60 need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a CO₂ monitor (or surrogate O₂ monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of §98.35.

(d) When municipal solid waste (MSW) is combusted in a unit, determine the biogenic portion of the CO₂ emissions from MSW combustion using ASTM D6866-08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, see §98.7) and ASTM D7459-08

Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, see §98.7). Perform the ASTM D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions while MSW is the only fuel being combusted for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08. Separate CO₂ emissions into the biogenic and non-biogenic fraction using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30, if 30 percent of the CO₂ from MSW combustion is biogenic). If there is a common fuel source of MSW that feeds multiple units at the facility, performing the testing at only one of the units is sufficient.

(e) For units that use CEMS to measure the total CO₂ mass emissions and combust a combination of biogenic fuels (other than MSW) with a fossil fuel, ASTM D6866-08 and ASTM D7459-08 may be used to determine the biogenic portion of the CO₂ emissions. Perform the ASTM D7459-08 sampling and

the ASTM D6866-08 analysis at least once in every calendar quarter in which biogenic and non-biogenic fuels are co-fired in the unit. The relative proportions of the biogenic and non-biogenic fuels during the sampling shall be representative of the average fuel blend for a typical operating year. Collect each gas sample using ASTM D7459-08 during normal unit operation for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08.

(f) Whenever company records are used in the calculation of CO₂ emissions, the records required under §98.3(g) shall include both the company records and an explanation of how those records are used to estimate the following parameters:

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

(3) Fossil fuel consumption when §98.33(e) applies to a unit that uses CEMS to quantify CO₂ emissions and that combusts both fossil and biomass fuels.

(4) Sorbent usage, when §98.33(d) applies.

(5) Quantity of steam generated by a unit when §98.33(a)(2) applies.

(6) Biogenic fuel consumption under §98.33(e) (5).

(g) As part of the GHG Monitoring Plan required under §98.3(g) (5), you must document the procedures used to ensure the accuracy of the estimates of fuel usage, sorbent usage, steam production, and boiler efficiency (as applicable) in paragraph (f) of this section, including but not limited to calibration of weighing equipment, fuel flow meters, steam flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§98.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data in accordance with 40 CFR part 75, the missing data substitution procedures in 40 CFR part 75 shall be followed for CO₂ concentration,

stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value has not been obtained by the time that the GHG emissions report is due, you may use the "before" value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO₂ concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production,

operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§98.36 Data reporting requirements.

(a) In addition to the facility-level information required under §98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) Units that use the four tiers. You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in §98.33(a) to calculate CO₂ emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

- (1) The unit ID number.
- (2) A code representing the type of unit.
- (3) Maximum rated heat input capacity of the unit, in mmBtu/hr for boilers and process heaters only and relevant units of measure for other combustion sources.
- (4) Each type of fuel combusted in the unit during the report year.
- (5) The tier used to calculate the CO₂ emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).

(6) For a unit that uses Tiers 1, 2, and 3; the CO₂, CH₄, and N₂O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO₂e.

(7) For a unit that uses Tier 4:

(i) For units that burn fossil fuels only, the annual CO₂ emissions for all fuels combined. Reporting CO₂ emissions by type of fuel is not required.

(ii) For units that burn both fossil fuels and biomass, the annual CO₂ emissions from combustion of all fossil fuels combined and the annual CO₂ emissions from combustion of all biomass fuels combined. Reporting CO₂ emissions by type of fuel is not required.

(iii) Annual CH₄ and N₂O emissions for each type of fuel combusted expressed in metric tons of each gas and in metric tons of CO₂e.

(8) Annual CO₂ emissions from sorbent (if calculated using Equation C-11 of this subpart), expressed in metric tons.

(9) Annual GHG emissions from all fossil fuels burned in the unit (i.e., the sum of the CO₂, CH₄, and N₂O emissions), expressed in metric tons of CO₂e.

(10) Customer meter number for units that combust natural gas.

(c) Reporting alternatives for units using the four Tiers. You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

(1) Aggregation of units. If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix "GP".

(ii) An identification number for each unit in the group.

(iii) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).

(iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).

(v) Each type of fuel combusted in the group of units during the reporting year.

(vi) Annual CO₂, CH₄, and N₂O mass emissions aggregated for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO₂e. If any of the units burn both fossil fuels and biomass, report also the annual CO₂ emissions from combustion of all fossil fuels combined and annual CO₂ emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The tier used to calculate the CO₂ mass emissions for each type of fuel combusted in the units (i.e., Tier 1, Tier 2, or Tier 3).

(viii) The calculated CO₂ mass emissions (if any) from sorbent.

(ix) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO₂, CH₄, and N₂O emissions), expressed in metric tons of CO₂e.

(2) Monitored common stack or duct configurations.
When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO₂ mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of

separately reporting the GHG emissions from the individual units. The following information shall be reported instead of the information in paragraph (b) of this section:

- (i) Common stack or duct identification number, beginning with the prefix "CS".
- (ii) Identification numbers of the units sharing the common stack or duct.
- (iii) Maximum rated heat input capacity of each unit sharing the common stack or duct (mmBtu/hr).
- (iv) Each type of fuel combusted in the units during the year.
- (v) The methodology used to calculate the CO₂ mass emissions, i.e., Tier 4.
- (vi) If the any of the units burn both fossil fuels and biomass, annual CO₂ mass emissions, annual CO₂ emissions from combustion of fossil fuels, and annual CO₂ emissions from combustion of biomass measured at the common stack or duct, expressed in metric tons.
- (vii) The annual CH₄ and N₂O emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO₂e.
- (viii) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO₂ , CH₄, and N₂O emissions), expressed in metric tons of CO₂e.

(3) 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 that is calibrated in accordance with §98.34(a). If a portion of the fuel measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, you may subtract the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations, provided that the amount of fuel diverted is also measured with a calibrated flow meter per §98.3(i). If the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration. The following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe identification number, beginning with the prefix "CP".

(ii) The identification numbers of the units served by the common pipe.

(iii) Maximum rated heat input capacity of each unit served by the common pipe (mmBtu/hr).

(iv) The fuels combusted in the units during the reporting year.

(v) The methodology used to calculate the CO₂ mass emissions (i.e., Tier 1, Tier 2, or Tier 3).

(vi) If the any of the units burns both fossil fuels and biomass, the annual CO₂ mass emissions from combustion of all fossil fuels and annual CO₂ emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

(vii) Annual CH₄ and N₂O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO₂e.

(viii) Annual GHG emissions from all fossil fuels burned in units served by the common pipe (i.e., the sum of the CO₂, CH₄, and N₂O emissions), expressed in metric tons of CO₂e.

(d) Units subject to 40 CFR part 75.

(1) For stationary combustion units that are either subject to the Acid Rain Program or not in the Acid Rain Program but monitor and report CO₂ mass emissions year-round according to 40 CFR part 75, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under §75.64 of this chapter.

(ii) Annual CO₂, CH₄, and N₂O emissions at each monitored location, expressed in metric tons of CO₂e.

(iii) Identification of the Part 75 methodology used to determine the CO₂ mass emissions.

(2) For units that use the alternative CO₂ mass emissions calculation methods for units with continuous monitoring systems provided in §98.33(a)(5), you shall report the following unit-level information:

(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, etc.) that are reported under §75.64 of this chapter.

(ii) For units that use the alternative methods specified in §98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to 40 CFR part 75 or 40 CFR 75.19:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO₂ mass emissions for each fuel type.

(C) A code or flag to indicate whether heat input is calculated according to appendix D to 40 CFR part 75 or 40 CFR 75.19.

(D) Annual CO₂, CH₄, and N₂O emissions at each monitored location, across all fuel types, expressed in metric tons of CO₂e.

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in §98.33(a)(5)(iii) to monitor heat input year-round according to 40 CFR part 75:

(A) Fuel combusted during the reporting year.

(B) Methodology used to calculate the CO₂ mass emissions.

(C) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(D) The total annual CO₂, CH₄, and N₂O emissions at each monitored location, expressed in metric tons of CO₂e.

(e) Verification data. You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:

(i) Are subject to the Acid Rain Program.

(ii) Use the alternative methods for units with continuous monitoring systems provided in §98.33(a)(5).

(iii) Are not in the Acid Rain Program, but are required monitor and report CO₂ mass emissions and heat input data year-round, in accordance with 40 CFR part 75.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in §98.33(a) to quantify CO₂ emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the

unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).

(C) The high heat values used in the CO₂ emissions calculations for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Specify the date on which each fuel sample was taken. Indicate whether each HHV is a measured value or a substitute data value.

(D) If Equation C-2c of this subpart is used to calculate CO₂ mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during the year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken.

(iv) For the Tier 3 Calculation Methodology, report:

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during the year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). Report all measured values if the fuel is sampled monthly or less frequently. Otherwise, for daily and weekly sampling, report monthly average values determined using the calculation procedures in Equation C-2b for each variable. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from §98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content for each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters).

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO₂ mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values

calculated from Equation C-6 or C-7 of this subpart (as applicable), in metric tons.

(C) For CO₂ concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO₂ emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio ("R") in Equation C-11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when CEMS are used to quantify the annual CO₂ emissions and biogenic CO₂ is determined according to §98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO₂ emitted from the combustion of all fuels, i.e., V_{total} , in scf.

(B) The annual volume of CO₂ emitted from the combustion of fossil fuels, i.e., V_{ff} , in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO₂ for each fuel separately as well as the total.

(C) The annual volume of CO₂ emitted from the combustion of biomass, i.e., V_{bio} , in scf.

(D) The carbon-based F-factor used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in scf CO₂ per mmBtu.

(E) The annual average HHV value used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO₂ mass emissions, in metric tons.

(x) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO₂ emissions from MSW combustion, report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO₂ emissions from MSW combustion is 30 percent, report 0.30).

(B) Annual combined biomass and fossil fuel CO₂ emissions from MSW combustion, in metric tons of CO₂e.

(C) The quantities V_{ff} , V_{total} , and V_{MSW} from §98.33(e)(4)(ii), if CEMS are used to measure CO₂ emissions.

(D) The annual volume of biogenic CO₂ emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO₂ emissions from a unit that co-fires biogenic (other than MSW) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO₂ emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO₂ emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO₂ emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO₂ emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO₂ mass emissions under §98.33(a)(2)(iii) or to quantify solid fuel usage under §98.33(c)(3).

(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

§98.37 Records That Must be Retained.

In addition to the requirements of §98.3(g), you must retain the applicable records specified in §§98.34(f) and (g), 98.35(b), and 98.36(e).

§98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table C-1 of Subpart C—Default CO₂ Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO₂ Emission Factor
Coal and Coke	mmBtu/short ton	kg CO₂ /mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural Gas	mmBtu/scf	kg CO₂ /mmBtu
Pipeline (Weighted U.S. Average)	1.028 x 10 ⁻³	53.02
Petroleum Products	mmBtu/gallon	kg CO₂ /mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73

Table C-1 of Subpart C—Default CO₂ Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO ₂ Emission Factor
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil Fuel-derived Fuels (Solid)	mmBtu/short ton	kg CO₂ /mmBtu
Municipal Solid Waste ¹	9.95	90.7
Tires	26.87	85.97
Fossil Fuel-derived Fuels (Gaseous)	mmBtu/scf	kg CO₂ /mmBtu
Blast Furnace Gas	0.092 × 10 ⁻³	274.32
Coke Oven Gas	0.599 × 10 ⁻³	46.85
Biomass Fuels - Solid	mmBtu/short Ton	kg CO₂ /mmBtu
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass Fuels - Gaseous	mmBtu/scf	kg CO₂ /mmBtu
Biogas (Captured methane)	0.841 × 10 ⁻³	52.07
Biomass Fuels - Liquid	mmBtu/gallon	kg CO₂ /mmBtu
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

¹Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH₄ and N₂O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH ₄ Emission Factor (kg CH ₄ /mmBtu)	Default N ₂ O Emission Factor (kg N ₂ O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1 × 10 ⁻²	1.6 × 10 ⁻⁰³
Natural Gas	1.0 × 10 ⁻⁰³	1.0 × 10 ⁻⁰⁴

Fuel Type	Default CH ₄ Emission Factor (kg CH ₄ /mmBtu)	Default N ₂ O Emission Factor (kg N ₂ O/mmBtu)
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels - Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH₄/MMBtu.

¹Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C-Default CH₄ and N₂O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH ₄ Emission Factor (kg CH ₄ /mmBtu)	Default N ₂ O Emission Factor (kg N ₂ O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels - Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH₄/MMBtu.

Subpart D-Electricity Generation

§98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in §98.6.

§98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of §98.2(a)(1).

§98.42 GHGs to report.

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR part 75, you must report under this subpart the annual mass emissions of CO₂, N₂O, and CH₄ by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO₂ emissions year-round according

to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O by following the requirements of subpart C of this part.

§98.43 Calculating GHG emissions.

Continue to monitor and report CO₂ mass emissions as required under §75.13 or section 2.3 of appendix G to 40 CFR part 75, and §75.64. Calculate CO₂, CH₄, and N₂O emissions as follows:

(a) Convert the cumulative annual CO₂ mass emissions reported in the fourth quarter electronic data report required under §75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(b) Calculate and report annual CH₄ and N₂O mass emissions under this subpart by following the applicable method specified in §98.33(c).

§98.44 Monitoring and QA/QC requirements

Follow the applicable quality assurance procedures for CO₂ emissions in appendices B, D, and G to 40 CFR part 75.

§98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in §98.36(b) and, if applicable, §98.36(c) (2) or (c) (3).

§98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§98.3(g) and 98.37.

§98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart E—Adipic Acid Production

§98.50 Definition of Source Category.

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§98.51 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an adipic acid production process

and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.52 GHGs to report.

(a) You must report N₂O process emissions at the facility level.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C.

§98.53 Calculating GHG emissions.

(a) You must determine annual N₂O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Administrator approval for an alternative method of determining N₂O emissions according to paragraphs (a)(2)(i) and (a)(2)(ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of

the reporting year, you must determine the N₂O emissions factor for the current reporting period using the procedures specified in paragraphs (b) through (h) of this section.

(b) You must conduct an annual performance test according to paragraphs (b)(1) through (b)(3) of this section.

(1) You must conduct the test on the waste gas stream from the nitric acid oxidation step of the process using the methods specified in §98.54(b) through (d).

(2) You must conduct the performance test under normal process operating conditions and without using N₂O abatement technology.

(3) You must measure the adipic acid production rate during the test and calculate the production rate for the test period in metric tons per hour.

(c) You must determine an N₂O emissions factor to use in Equation E-2 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Administrator approval for an alternative method of determining N₂O concentration according to the procedures in paragraphs (a)(2)(i) and (a)(2)(ii) of this section. Alternative methods include the use of N₂O CEMs.

(2) Using the results of the performance test in paragraph (b) of this section, you must calculate a facility-specific emissions factor according to Equation E-1 of this section:

$$EF_{N_2O} = \frac{\sum_1^n \frac{C_{N_2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \quad (\text{Eq. E-1})$$

Where:

- EF_{N_2O} = Average facility-specific N_2O emissions factor (lb N_2O generated/ton adipic acid produced).
- C_{N_2O} = N_2O concentration per test run during the performance test (ppm N_2O).
- 1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).
- Q = Volumetric flow rate of effluent gas per test run during the performance test (dscf/hr).
- P = Production rate per test run during the performance test (tons adipic acid produced/hr).
- n = Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology used at your facility according to paragraphs (d) (1), (d) (2), or (d) (3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the

current vent stream conditions. You must document how process knowledge was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N₂O abatement technology.

(e) If applicable, you must determine the abatement factor for each N₂O abatement technology used at your facility. The abatement factor is calculated for each adipic acid facility according to Equation E-2 of this section.

$$AF_N = \frac{P_{a \text{ Abate}}}{P_a} \quad (\text{Eq. E-2})$$

Where:

AF_N = Abatement factor of N₂O abatement technology (fraction of annual production that abatement technology is operating).

P_{a Abate} = Annual adipic acid production during which N₂O abatement was used.

P_a = Total annual adipic acid production (ton acid produced).

(f) You must determine the annual amount of adipic acid produced and the annual adipic acid production during which N₂O abatement is operating.

(g) You must calculate annual adipic acid production process emissions of N₂O by multiplying the emissions factor (determined using Equation E-1 of this section) by the

total annual adipic acid production and accounting for N₂O abatement, according to Equation E-3 of this section:

$$N_2O = \sum_1^N \frac{EF_{N20} * P_a * (1 - (DF_N * AF_N))}{2205} \quad (\text{Eq. E-3})$$

Where:

- N₂O = Annual N₂O mass emissions from adipic acid production (metric tons).
- EF_{N20} = Facility-specific N₂O emissions factor (lb N₂O generated/ton adipic acid produced).
- P_a = Annual adipic acid produced (tons).
- DF_N = Destruction efficiency of N₂O abatement technology N (abatement device destruction efficiency, percent of N₂O removed from air stream).
- AF_N = Abatement factor of N₂O abatement technology N (fraction of annual production abatement technology is operating).
- 2205 = Conversion factor (lb/metric ton).
- N = Number of different N₂O abatement technologies.

(h) You must determine the amount of process N₂O emissions that is sold or transferred off site (if applicable). You can determine the amount using existing process flow meters and N₂O analyzers.

§98.54 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new facility-specific emissions factor according to the frequency specified in paragraphs (a)(1) through (a)(3) of this section.

- (1) Conduct the performance test annually.
- (2) Conduct the performance test when your adipic acid production process is changed either by altering the

ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(3) If you requested Administrator approval for an alternative method of determining N₂O concentration under §98.53(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N₂O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63, Appendix A;

(2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, see §98.7); or

(3) An equivalent method, with Administrator approval.

(c) You must determine the production rate(s) during the performance test according to paragraph (c)(1) or (c)(2) of this section.

(1) Direct measurement (such as using flow meters or weigh scales).

(2) Existing plant procedures used for accounting purposes.

(d) You must conduct all required performance tests according to the methods in §98.54(b) in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A-1 through A-4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate(s) during the performance test and how each production rate was determined.

(e) You must determine the monthly adipic acid production quantity and the monthly adipic acid production during which N₂O abatement technology is operating according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) You must determine the annual adipic acid production quantity and the annual adipic production quantity during which N₂O abatement technology is operating by summing the respective monthly adipic acid production quantities.

§98.55 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N₂O concentration, you must conduct a new performance test according to the procedures in §98.54 (a) through (d).

§98.56 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified

in paragraphs (a) through (k) of this section at the facility level:

(a) Annual process N₂O emissions from adipic acid production (metric tons).

(b) Annual adipic acid production (tons).

(c) Annual adipic acid production during which N₂O abatement technology is operating (tons).

(d) Annual process N₂O emissions from adipic acid production facility that is sold or transferred off site (metric tons).

(e) Number of abatement technologies (if applicable).

(f) Types of abatement technologies used (if applicable).

(g) Abatement technology destruction efficiency for each abatement technology (percent destruction).

(h) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).

(i) Number of times in the reporting year that missing data procedures were followed to measure adipic acid production (months).

(j) If you conducted a performance test and calculated a site-specific emissions factor according to §98.53(a)(1), each annual report must also contain the

information specified in paragraphs (j) (1) through (j) (7) of this section for each adipic acid production facility.

- (1) Emissions factor (lb N₂O/ton adipic acid).
- (2) Test method used for performance test.
- (3) Production rate per test run during performance test (tons/hr).
- (4) N₂O concentration per test run during performance test (ppm N₂O).
- (5) Volumetric flow rate per test run during performance test (dscf/hr).
- (6) Number of test runs.
- (7) Number of times in the reporting year that a performance test had to be repeated (number).

(k) If you requested Administrator approval for an alternative method of determining N₂O concentration under §98.53(a) (2), each annual report must also contain the information specified in paragraphs (k) (1) through (k) (4) of this section for each adipic acid production facility.

- (1) Name of alternative method.
- (2) Description of alternative method.
- (3) Request date.
- (4) Approval date.

§98.57 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a) through (h) of this section at the facility level:

- (a) Annual adipic acid production capacity (tons).
- (b) Records of significant changes to process.
- (c) Number of facility operating hours in calendar year.
- (d) Documentation of how accounting procedures were used to estimate production rate.
- (e) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency.
- (f) Performance test reports of N₂O emissions.
- (g) Measurements, records and calculations used to determine reported parameters.
- (h) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.58 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart F—Aluminum Production§98.60 Definition of the source category.

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

- (1) Electrolysis in prebake and Søderberg cells.
- (2) Anode baking for prebake cells.

(b) This source category does not include experimental cells or research and development process units.

§98.61 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an aluminum production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.62 GHGs to report.

You must report:

(a) Perfluoromethane (CF₄), and perfluoroethane (C₂F₆) emissions from anode effects in all prebake and Søderberg electrolysis cells.

(b) CO₂ emissions from anode consumption during electrolysis in all prebake and Søderberg electrolysis cells.

(c) CO₂ emissions from on-site anode baking.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, N₂O, and CH₄ emissions from each stationary fuel combustion unit by following the requirements of subpart C. §98.63 Calculating GHG emissions.

(a) The annual value for PFC emissions shall be estimated from the sum of monthly values using Equation F-1 of this section:

$$E_{PFC} = \sum_{m=1}^{m=12} E_m \quad (\text{Eq. F-1})$$

Where:

E_{PFC} = Annual PFC emissions from aluminum production (metric tons PFC).

E_m = PFC emissions from aluminum production for the month "m" (metric tons PFC).

(b) Use Equation F-2 of this section to estimate CF₄ emissions from anode effect duration or Equation F-3 of this section to estimate CF₄ emissions from overvoltage, and use Equation F-4 of this section to estimate C₂F₆ emissions from anode effects from each prebake and Søderberg electrolysis cell.

$$E_{CF4} = S_{CF4} \times AEM \times MP \times 0.001 \quad (\text{Eq. F-2})$$

Where:

E_{CF4} = Monthly CF₄ emissions from aluminum production (metric tons CF₄).

S_{CF4} = The slope coefficient ((kg CF₄/metric ton Al)/(AE-Mins/cell-day)).

- AEM = The anode effect minutes per cell-day (AE-Mins/cell-day).
- MP = Metal production (metric tons Al), where AEM and MP are calculated monthly.

$$E_{CF_4} = EF_{CF_4} \times MP \times 0.001 \quad (\text{Eq. F-3})$$

Where:

- E_{CF_4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).
- EF_{CF_4} = The overvoltage emission factor (kg CF_4 /metric ton Al).
- MP = Metal production (metric tons Al), where MP is calculated monthly.

$$E_{C_2F_6} = E_{CF_4} \times F_{C_2F_6/CF_4} \times 0.001 \quad (\text{Eq. F-4})$$

Where:

- $E_{C_2F_6}$ = Monthly C_2F_6 emissions from aluminum production (metric tons C_2F_6).
- E_{CF_4} = CF_4 emissions from aluminum production (kg CF_4).
- $F_{C_2F_6/CF_4}$ = The weight fraction of C_2F_6/CF_4 (kg C_2F_6 /kg CF_4).
- 0.001 = Conversion factor from kg to metric tons, where E_{CF_4} is calculated monthly.

(c) You must calculate and report the annual process CO_2 emissions from anode consumption during electrolysis and anode baking of prebake cells using either the procedures in paragraph (d) of this section or the procedures in paragraphs (e) and (f) of this section.

(d) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in §98.33(a) (4) and all associated requirements for Tier 4 in

subpart C of this part (General Stationary Fuel Combustion Sources).

(e) Use the following procedures to calculate CO₂ emissions from anode consumption during electrolysis:

(1) For Prebake cells: you must calculate CO₂ emissions from anode consumption using Equation F-5 of this section:

$$E_{CO_2} = NAC \times MP \times ([100 - S_a - Ash_a] / 100) \times (44/12) \quad (\text{Eq. F-5})$$

Where:

E_{CO_2} = Annual CO₂ emissions from prebaked anode consumption (metric tons CO₂).

NAC = Net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al).

MP = Annual metal production (metric tons Al).

S_a = Sulfur content in baked anode (percent weight).

Ash_a = Ash content in baked anode (percent weight).

44/12 = Ratio of molecular weights, CO₂ to carbon.

(2) For Søderberg cells you must calculate CO₂ emissions using Equation F-6 of this section:

$$E_{CO_2} = (PC \times MP - [CSM \times MP] / 1000 - BC / 100 \times PC \times MP \times [S_p + Ash_p + H_p] / 100 - [100 - BC] / 100 \times PC \times MP \times [S_c + Ash_c] / 100 - MP \times CD) \times (44/12) \quad (\text{Eq. F-6})$$

Where:

E_{CO_2} = Annual CO₂ emissions from paste consumption (metric ton CO₂).

PC = Annual paste consumption (metric ton/metric ton Al).

MP = Annual metal production (metric ton Al).

CSM = Annual emissions of cyclohexane soluble matter (kg/metric ton Al).

BC = Binder content of paste (percent weight).

S_p = Sulfur content of pitch (percent weight).

- Ash_p = Ash content of pitch (percent weight).
 H_p = Hydrogen content of pitch (percent weight).
 S_c = Sulfur content in calcined coke (percent weight).
 Ash_c = Ash content in calcined coke (percent weight).
 CD = Carbon in skimmed dust from Søderberg cells
(metric ton C/metric ton Al).
 $44/12$ = Ratio of molecular weights, CO_2 to carbon.
(e) Use the following procedures to calculate CO_2

emissions from anode baking of prebake cells:

- (1) Use Equation F-7 of this section to calculate emissions from pitch volatiles combustion.

$$E_{CO_2PV} = (GA - H_w - BA - WT) \times (44/12) \quad (\text{Eq. F-7})$$

Where:

- E_{CO_2PV} = Annual CO_2 emissions from pitch volatiles
combustion (metric tons CO_2).
 GA = Initial weight of green anodes (metric tons).
 H_w = Annual hydrogen content in green anodes (metric
tons).
 BA = Annual baked anode production (metric tons).
 WT = Annual waste tar collected (metric tons).
 $44/12$ = Ratio of molecular weights, CO_2 to carbon.

- (2) Use Equation F-8 of this section to calculate emissions from bake furnace packing material.

$$E_{CO_2PC} = PCC \times BA \times ([100 - S_{pc} - Ash_{pc}] / 100) \times (44/12) \quad (\text{Eq. F-8})$$

Where:

- E_{CO_2PC} = Annual CO_2 emissions from bake furnace packing
material (metric tons CO_2).
 PCC = Annual packing coke consumption (metric
tons/metric ton baked anode).
 BA = Annual baked anode production (metric tons).
 S_{pc} = Sulfur content in packing coke (percent weight).
 Ash_{pc} = Ash content in packing coke (percent weight).
 $44/12$ = Ratio of molecular weights, CO_2 to carbon.

(f) If process CO₂ emissions from anode consumption during electrolysis or anode baking of prebake cells are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraphs (d) and (e) of this section shall not be used to calculate those process emissions. The owner or operation shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§98.64 Monitoring and QA/QC requirements.

(a) Effective one year after publication of the rule for smelters with no prior measurement or effective three years after publication for facilities with historic measurements, the smelter-specific slope coefficients used in Equations F-2, F-3, and F-4 of this subpart must be measured in accordance with the recommendations of the EPA/IAI Protocol for Measurement of Tetrafluoromethane (CF₄) and Hexafluoroethane (C₂F₆) Emissions from Primary Aluminum Production (2008), except the minimum frequency of

measurement shall be every 10 years unless a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine. Facilities which operate at less than 0.2 anode effect minutes per cell day or operate with less than 1.4mV anode effect overvoltage can use either smelter-specific slope coefficients or the technology specific default values in Table F-1 of this subpart.

(b) The minimum frequency of the measurement and analysis is annually except as follows: Monthly - anode effect minutes per cell day (or anode effect overvoltage and current efficiency), production.

(c) Sources may use either smelter-specific values from annual measurements of parameters needed to complete the equations in §98.63 (e.g., sulfur, ash, and hydrogen contents) or the default values shown in Table F-2 of this subpart.

§98.65 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample measurement is not taken), a substitute data value for the missing parameter

shall be used in the calculations, according to the following requirements:

(a) Where anode or paste consumption data are missing, CO₂ emissions can be estimated from aluminum production using Tier 1 method per Equation F-8 of this section.

$$ECO_2 = EF_p \times MP_p + EF_s \times MP_s \quad (\text{Eq. F-8})$$

Where:

ECO₂ = CO₂ emissions from anode and/or paste consumption, metric tons CO₂.

EF_p = Prebake technology specific emission factor (1.6 metric tons CO₂/metric ton aluminum produced).

MP_p = Metal production from prebake process (metric tons Al).

EF_s = Søderberg technology specific emission factor (1.7 metric tons CO₂/metric ton Al produced).

MP_s = Metal production from Søderberg process (metric tons Al).

(b) For other parameters, use the average of the two most recent data points after the missing data.

§98.66 Data reporting requirements.

In addition to the information required by §98.3(c), you must report the following information at the facility level:

(a) Annual aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on an annual basis:

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electrolysis cells combined.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF₄/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).)

(3) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured.

(d) Method used to measure the frequency and duration of anode effects (or overvoltage).

(e) The following CO₂-specific information for prebake cells:

- (1) Annual anode consumption.
- (2) Annual CO₂ emissions from the smelter.

(f) The following CO₂-specific information for Søderberg cells:

- (1) Annual paste consumption.
- (2) Annual CO₂ emissions from the smelter.

(g) Smelter-specific inputs to the CO₂ process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Söderberg) and process control technology (e.g., Pechiney or other).

§98.67 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the following records:

- (a) Monthly aluminum production in metric tons.
- (b) Type of smelter technology used.
- (c) The following PFC-specific information on a monthly basis:

(1) Perfluoromethane and perfluoroethane emissions from anode effects in prebake and Söderberg electrolysis cells.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF₄/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).))

(3) Smelter-specific slope coefficients and the last date when the smelter-specific-slope coefficients were measured.

(d) Method used to measure the frequency and duration of anode effects (or to measure anode effect overvoltage and current efficiency).

(e) The following CO₂-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO₂ emissions from the smelter.

(f) The following CO₂-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO₂ emissions from the smelter.

(g) Smelter-specific inputs to the CO₂ process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§98.68 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table F-1 of Subpart F—Slope and Overvoltage Coefficients for the Calculation of PFC Emissions from Aluminum Production

Technology	CF₄ Slope Coefficient [(kg CF₄/metric ton Al)/(AE-Mins/cell-day)]	CF₄ Overvoltage Coefficient [(kg CF₄/metric ton Al)/(mV)]	Weight Fraction C₂F₆/CF₄ [(kg C₂F₆/kg CF₄)]
CWPB	0.143	1.16	0.121
SWPB	0.272	3.65	0.252
VSS	0.092	NA	0.053
HSS	0.099	NA	0.085

Table F-2 of Subpart F—Default Data Sources for Parameters Used for CO₂ Emissions

CO₂ Emissions from Prebake Cells (CWPB and SWPB)	
Parameter	Data Source
MP: metal production (metric tons Al)	Individual facility records
NAC: net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al)	Individual facility records
S _a : sulfur content in baked anode (percent weight)	2.0
Ash _a : ash content in baked anode (percent weight)	0.4
CO₂ Emissions from Søderberg Cells (VSS and HSS)	
Parameter	Data Source
MP: metal production (metric tons Al)	Individual facility records
PC: annual paste consumption (metric ton/metric ton Al)	Individual facility records
CSM: annual emissions of cyclohexane soluble matter (kg/metric ton Al)	HSS: 4.0 VSS: 0.5
BC: binder content of paste (percent weight)	Dry Paste: 24 Wet Paste: 27
S _p : sulfur content of pitch (percent weight)	0.6
Ash _p : ash content of pitch (percent weight)	0.2
H _p : hydrogen content of	3.3

pitch (percent weight)	
S _c : sulfur content in calcined coke (percent weight)	1.9
Ash _c : ash content in calcined coke (percent weight)	0.2
CD: carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al)	0.01
CO ₂ Emissions from Pitch Volatiles Combustion (VSS and HSS)	
Parameter	Data Source
GA: initial weight of green anodes (metric tons)	Individual facility records
H _w : annual hydrogen content in green anodes (metric tons)	0.005 × GA
BA: annual baked anode production (metric tons)	Individual facility records
WT: annual waste tar collected (metric tons) (a) Riedhammer furnaces (b) all other furnaces	(a) 0.005 × GA (b) insignificant
CO ₂ Emissions from Bake Furnace Packing Materials (CWPB and SWPB)	
Parameter	Data Source
PCC: annual packing coke consumption (metric tons/metric ton baked anode)	0.015
BA: annual baked anode production (metric tons)	Individual facility records
S _{pc} : sulfur content in packing coke (percent weight)	2
Ash _{pc} : ash content in packing coke (percent weight)	2.5

Subpart G—Ammonia Manufacturing

§98.70 Definition of Source Category.

The ammonia manufacturing source category comprises the process units listed in paragraphs (a) and (b) of this section.

(a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.

(b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

§98.71 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an ammonia manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.72 GHGs to report.

You must report:

(a) CO₂ process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing process unit following the requirements in this subpart.

(b) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel

Combustion Sources), by following the requirements of subpart C.

(c) CO₂ emissions collected and transferred off site under subpart PP (Suppliers of CO₂), following the requirements of subpart PP.

§98.73 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart process CO₂ emissions using the procedures in paragraphs (b)(1) through (b)(6) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) Gaseous feedstock. You must calculate, from each ammonia manufacturing unit, the CO₂ process emissions from gaseous feedstock according to Equation G-1 of this section:

$$CO_{2,G,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n * \frac{MW}{MVC} \right) * 0.001 \quad (\text{Eq. G-1})$$

Where:

- $CO_{2,G}$ = Annual CO_2 emissions arising from feedstock consumption (metric tons).
- $Fdstk_n$ = Volume of the gaseous feedstock used in month n (scf of feedstock).
- CC_n = Carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock), determined according to 98.74(c).
- MW = Molecular weight of the gaseous feedstock (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
- 44/12 = Ratio of molecular weights, CO_2 to carbon.
- 0.001 = Conversion factor from kg to metric tons.
- k = Processing unit.
- n = Number of month

(2) Liquid feedstock. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to Equation G-2 of this section:

$$CO_{2,L,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n \right) * 0.001 \quad (\text{Eq. G-2})$$

Where:

- $CO_{2,L}$ = Annual CO_2 emissions arising from feedstock consumption (metric tons).
- $Fdstk_n$ = Volume of the liquid feedstock used in month n (gallons of feedstock).
- CC_n = Carbon content of the liquid feedstock, for month n, (kg C per gallon of feedstock) determined according to 98.74(c).
- 44/12 = Ratio of molecular weights, CO_2 to carbon.
- 0.001 = Conversion factor from kg to metric tons.
- k = Processing unit.
- n = Number of month

(3) Solid feedstock. You must calculate, from each ammonia manufacturing unit, the CO₂ process emissions from solid feedstock according to Equation G-3 of this section:

$$CO_{2,s,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n \right) * 0.001 \quad (\text{Eq. G-3})$$

Where:

CO_{2,s} = Annual CO₂ emissions arising from feedstock consumption (metric tons).

Fdstk_n = Mass of the solid feedstock used in month n (kg of feedstock).

CC_n = Carbon content of the solid feedstock, for month n, (kg C per kg of feedstock), determined according to 98.74(c).

44/12 = Ratio of molecular weights, CO₂ to carbon.

0.001 = Conversion factor from kg to metric tons.

K = Processing unit.

n = Number of month.

(4) You must calculate the annual process CO₂ emissions from each ammonia processing unit k at your facility summing emissions, as applicable from Equation G-1, G-2, and G-3 of this section using Equation G-4.

$$E_{CO_2k} = CO_{2,G} + CO_{2,S} + CO_{2,L} \quad (\text{Eq. G-4})$$

Where:

E_{CO₂k} = Annual CO₂ emissions from each ammonia processing unit k (metric tons).

k = Processing unit.

(5) You must determine the combined CO₂ emissions from all ammonia processing units at your facility using Equation G-5 of this section.

$$\text{CO}_2 = \sum_{k=1}^n E_{\text{CO}_2_k} \quad (\text{Eq. G-5})$$

Where:

CO₂ = Annual combined CO₂ emissions from all ammonia processing units (metric tons).

E_{CO₂_k} = Annual CO₂ emissions from each ammonia processing unit (metric tons).

k = Processing unit.

n = Total number of ammonia processing units.

(6) If applicable, ammonia manufacturing facilities that utilize the waste recycle stream as a fuel must calculate emissions associated with the waste stream for each ammonia process unit according to Equation G-6 of this section:

$$\text{CO}_2 = \left(\sum_{n=1}^{12} \frac{44}{12} * \text{RecycleStream}_n * \text{CC}_n * \frac{\text{MW}}{\text{MVC}} \right) * 0.001 \quad (\text{Eq. G-6})$$

Where:

CO₂ = Annual CO₂ contained in waste recycle stream (metric tons).

RecycleStream_n = Volume of the waste recycle stream in month n (scf).

CC_n = Carbon content of the waste recycle stream, for month n, (kg C per kg of waste recycle stream) determined according to 98.74(f).

MW = Molecular weight of the waste recycle stream (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO₂ to carbon.
0.001 = Conversion factor from kg to metric tons.
n = Number of month

(c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§98.74 Monitoring and QA/QC requirements.

(a) You must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(c) You must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from your supplier. As an alternative to using

supplier information on carbon contents, you can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c) (1) through (c) (8) of this section, as applicable.

(1) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(2) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements (incorporated by reference, see §98.7).

(4) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see §98.7).

(5) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(6) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(7) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

(8) ASTM D5373-08 Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(d) Calibrate all oil and gas flow meters (except for gas billing meters) and perform oil tank measurements according to the monitoring and QA/QC requirements for the Tier 3 methodology in §98.34(b).

(e) For quality assurance and quality control of the supplier data, on an annual basis, you must measure the carbon contents of a representative sample of the feedstocks consumed using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(f) Facilities must continuously measure the quantity of waste gas recycled using a flow meter, as applicable. You must determine the carbon content and the molecular

weight of the waste recycle stream by collecting a sample of each waste recycle stream on a monthly basis and analyzing the carbon content using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(g) If CO₂ from ammonia production is used to produce urea at the same facility, you must determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). You must document the procedures used to ensure the accuracy of the estimates of urea produced.

§98.75 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in §98.74 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-

assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

§98.76 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable for each ammonia manufacturing process unit.

(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.37(e) (2) (vi) for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Annual quantity of each type of feedstock consumed for ammonia manufacturing (scf of feedstock or gallons of feedstock or kg of feedstock).

(2) Method used for determining quantity of feedstock used.

(b) If a CEMS is not used to measure emissions, then you must report the following information:

(1) Annual CO₂ process emissions (metric tons) for each ammonia manufacturing process unit.

(2) Monthly quantity of each type of feedstock consumed for ammonia manufacturing for each ammonia processing unit (scf of feedstock or gallons of feedstock or kg of feedstock).

(3) Method used for determining quantity of monthly feedstock used.

(4) Whether carbon content for each feedstock for month n is based on reports from the supplier or analysis of carbon content.

(5) If carbon content of feedstock for month n is based on analysis, the test method used.

(6) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under §98.74(e).

(7) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock).

(8) If a facility uses gaseous feedstock, the molecular weight of the gaseous feedstock (kg/kg-mole).

(9) If a facility uses gaseous feedstock, the molar volume conversion factor of the gaseous feedstock (scf per kg-mole).

(10) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month n, (kg C per gallon of feedstock).

(11) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month n, (kg C per kg of feedstock).

(12) Annual CO₂ emissions associated with the waste recycle stream for each ammonia process unit (metric tons)

(13) Carbon content of the waste recycle stream for month n for each ammonia process unit (kg C per kg of waste recycle stream).

(14) Volume of the waste recycle stream for month n for each ammonia process unit (scf)

(15) Method used for analyzing carbon content of waste recycle stream.

(16) Annual urea production (metric tons) and method used to determine urea production.

(17) Uses of urea produced, if known, such as but not limited to fertilizer, animal feed, manufacturing of plastics or resins, and pollution control technologies.

(c) Total pounds of synthetic fertilizer produced through and total nitrogen contained in that fertilizer.

§98.77 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the following records specified in paragraphs (a) and (b) of this section for each ammonia manufacturing unit.

(a) If a CEMS is used to measure emissions, retain records of all feedstock purchases in addition to the requirements in §98.37 for the Tier 4 Calculation Methodology.

(b) If a CEMS is not used to measure process CO₂ emissions, you must also retain the records specified in paragraphs (b)(1) through (b)(2) of this section:

(1) Records of all analyses and calculations conducted for reported data as listed in §98.76(b).

(2) Monthly records of carbon content of feedstock from supplier and/or all analyses conducted of carbon content.

§98.78 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart H—Cement Production

§98.80 Definition of the source category.

The cement production source category consists of each kiln and each in-line kiln/raw mill at any portland cement manufacturing facility including alkali bypasses, and includes kilns and in-line kiln/raw mills that burn hazardous waste.

§98.81 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a cement production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.82 GHGs to report.

You must report:

- (a) CO₂ process emissions from calcination in each kiln.
- (b) CO₂ combustion emissions from each kiln.
- (c) CH₄ and N₂O combustion emissions from each kiln.

You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than kilns. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.83 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each kiln using the procedure in paragraphs (a) and (b) of this section.

(a) For each cement kiln that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each kiln that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO₂ emissions from the kiln by using the procedure in either paragraph (c) or (d) of this section.

(c) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating

and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(d) Calculate and report process and combustion CO₂ emissions separately using the procedures specified in paragraphs (d)(1) through (d)(4) of this section.

(1) Calculate CO₂ process emissions from all kilns at the facility using Equation H-1 of this section:

$$CO_{2CMF} = \sum_{m=1}^k CO_{2Cli,m} + CO_{2rm} \quad (\text{Eq. H-1})$$

Where:

- CO_{2 CMF} = Annual process emissions of CO₂ from cement manufacturing, metric tons.
- CO_{2 Cli,m} = Total annual emissions of CO₂ from clinker production from kiln m, metric tons.
- CO_{2 rm} = Total annual emissions of CO₂ from raw materials, metric tons.
- k = Total number of kilns at a cement manufacturing facility.

(2) CO₂ emissions from clinker production. Calculate CO₂ emissions from each kiln using Equations H-2 through H-5 of this section.

$$CO_{2 Cli,m} = \sum_{j=1}^p \left[(Cli,j) * (EF_{Cli,j}) * \frac{2000}{2205} \right] + \sum_{i=1}^r \left[(CKD,i) * (EF_{CKD,i}) * \frac{2000}{2205} \right] \quad (\text{Eq. H-2})$$

Where:

- $Cl_{i,j}$ = Quantity of clinker produced in month j from kiln m , tons.
- $EF_{Cl_{i,j}}$ = Kiln specific clinker emission factor for month j for kiln m , metric tons CO_2 /metric ton clinker computed as specified in Equation H-3 of this section.
- $CKD_{,i}$ = Cement kiln dust (CKD) not recycled to the kiln in quarter i from kiln m , tons.
- $EF_{CKD,i}$ = Kiln specific CKD emission factor for quarter i from kiln m , metric tons CO_2 /metric ton CKD computed as specified in Equation H-4 of this section.
- p = Number of months for clinker calculation, 12.
- r = Number of quarters for CKD calculation, 4.
- 2000/2205 = Conversion factor to convert tons to metric tons.

(i) Kiln-Specific Clinker Emission Factor. Calculate the kiln-specific clinker emission factor using Equation H-3 of this section.

$$EF_{Cl} = (Cl_{CaO} - Cl_{ncCaO}) * MR_{CaO} + (Cl_{MgO} - Cl_{ncMgO}) * MR_{MgO} \quad (\text{Eq. H-3})$$

Where:

- Cl_{CaO} = Monthly total CaO content of Clinker, wt-fraction.
- Cl_{ncCaO} = Monthly non-calcined CaO content of Clinker, wt-fraction.
- MR_{CaO} = Molecular-weight Ratio of CO_2 /CaO = 0.785.
- Cl_{MgO} = Monthly total MgO content of Clinker, wt-fraction.
- Cl_{ncMgO} = Monthly non-calcined MgO content of Clinker, wt-fraction.
- MR_{MgO} = Molecular-weight Ratio of CO_2 /MgO = 1.092.

Non-calcined CaO is CaO that remains in the clinker in the form of $CaCO_3$ and CaO in the clinker that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO

that remains in the clinker in the form of $MgCO_3$ and MgO in the clinker that entered the kiln as a non-carbonate species.

(ii) Kiln-Specific CKD Emission Factor. Calculate the kiln-specific CKD emission factor for CKD not recycled to the kiln using Equation H-4 of this section.

$$EF_{CKD} = (CKD_{CaO} - CKD_{ncCaO}) * MR_{CaO} + (CKD_{MgO} - CKD_{ncMgO}) * MR_{MgO} \quad (\text{Eq. H-4})$$

Where:

CKD_{CaO}	=	Quarterly total CaO content of CKD not recycled to the kiln, wt-fraction.
CKD_{CaO}	=	Quarterly non-calcined CaO content of CKD not recycled to the kiln, wt-fraction.
MR_{CaO}	=	Molecular-weight Ratio of $CO_2/CaO = 0.785$.
CKD_{MgO}	=	Quarterly total MgO content of CKD not recycled to the kiln, wt-fraction.
CKD_{MgO}	=	Quarterly non-calcined MgO content of CKD not recycled to the kiln, wt-fraction.
MR_{MgO}	=	Molecular-weight Ratio of $CO_2/MgO = 1.092$.

Non-calcined CaO is CaO that remains in the CKD in the form of $CaCO_3$ and CaO in the CKD that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO that remains in the CKD in the form of $MgCO_3$ and MgO in the CKD that entered the kiln as a non-carbonate species.

(3) CO_2 emissions from raw materials. Calculate CO_2 emissions using Equation H-5 of this section:

$$CO_{2,rm} = \sum_{i=1}^m rm * TOCr_{m} * \frac{44}{12} * \frac{2000}{2205} \quad (\text{Eq. H-5})$$

Where:

rm	=	The amount of raw material i consumed annually, tons/yr (dry basis).
CO _{2,rm}	=	Annual CO ₂ emissions from raw materials.
TOCr _m	=	Organic carbon content of raw material i (dry basis), as determined in §98.84(c) or using a default factor of 0.2 percent of total raw material weight.
M	=	Number of raw materials.
44/12	=	Ratio of molecular weights, CO ₂ to carbon.
2000/2205	=	Conversion factor to convert tons to metric tons.

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO₂ emissions from the kiln according to the applicable requirements in subpart C.

§98.84 Monitoring and QA/QC requirements.

(a) You must determine the weight fraction of total CaO and total MgO in CKD not recycled to the kiln from each kiln using ASTM C114-09, Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see §98.7). The monitoring must be conducted quarterly for each kiln from a CKD sample drawn either as CKD is exiting the kiln or from bulk CKD storage.

(b) You must determine the weight fraction of total CaO and total MgO in clinker from each kiln using ASTM C114-07 Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see §98.7).

The monitoring must be conducted monthly for each kiln from a clinker sample drawn from bulk clinker storage.

(c) The total organic carbon contents (dry basis) of each raw material must be determined annually using ASTM C114-09 Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see §98.7) or a similar industry standard practice or method approved for total organic carbon determination in raw mineral materials. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material (i.e., limestone, sand, shale, iron oxide, and alumina). Facilities that opt to use the default total organic carbon factor provided in §98.83(d)(3), are not required to monitor for TOC.

(d) The quantity of clinker produced monthly by each kiln must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of CKD not recycled to the kiln by each kiln must be determined quarterly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers, truck weigh scales, or belt weigh feeders.

(f) The quantity of each category of raw materials consumed annually by the facility (e.g., limestone, sand, shale, iron oxide, and alumina) must be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers, truck weigh scales, or belt weigh feeders.

(g) The monthly non-calcined CaO and MgO that remains in the clinker in the form of CaCO₃ or that enters the kiln as a non-carbonate species may be assumed to be a default value of 0.0 or may be determined monthly by careful chemical analysis of feed material and clinker material from each kiln using well documented analytical and calculational methods or the appropriate industry standard practice.

(h) The quarterly non-calcined CaO and MgO that remains in the CKD in the form of CaCO₃ or that enters the kiln as a non-carbonate species may be assumed to be a default value of 0.0 or may be determined quarterly by careful chemical analysis of feed material and CKD material from each kiln using well documented analytical and calculational methods or the appropriate industry standard practice.

§98.85 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.83 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations. The owner or operator must document and keep records of the procedures used for all such estimates.

(a) If the CEMS approach is used to determine combined process and combustion CO₂ emissions, the missing data procedures in §98.35 apply.

(b) For CO₂ process emissions from cement manufacturing facilities calculated according to §98.83(d), if data on the carbonate content (of clinker or CKD), noncalcined content (of clinker or CKD) or the annual organic carbon content of raw materials are missing, facilities must undertake a new analysis.

(c) For each missing value of monthly clinker production the substitute data value must be the best available estimate of the monthly clinker production based on information used for accounting purposes, or use the maximum tons per day capacity of the system and the number of days per month.

(d) For each missing value of monthly raw material consumption the substitute data value must be the best

available estimate of the monthly raw material consumption based on information used for accounting purposes (such as purchase records), or use the maximum tons per day raw material throughput of the kiln and the number of days per month.

§98.86 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as appropriate.

(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required by §98.36(e)(2)(vi) and the information listed in this paragraph(a):

(1) Monthly clinker production from each kiln at the facility.

(2) Monthly cement production from each kiln at the facility.

(3) Number of kilns and number of operating kilns.

(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b) for each kiln:

(1) Kiln identification number.

(2) Monthly clinker production from each kiln.

(3) Monthly cement production from each kiln.

(4) Number of kilns and number of operating kilns.

(5) Quarterly quantity of CKD not recycled to the kiln for each kiln at the facility.

(6) Monthly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in clinker for each kiln (as wt-fractions).

(7) Method used to determine non-calcined CaO and non-calcined MgO in clinker.

(8) Quarterly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in CKD not recycled to the kiln for each kiln (as wt-fractions).

(9) Method used to determine non-calcined CaO and non-calcined MgO in CKD.

(10) Monthly kiln-specific clinker CO₂ emission factors for each kiln (metric tons CO₂/metric ton clinker produced).

(11) Quarterly kiln-specific CKD CO₂ emission factors for each kiln (metric tons CO₂/metric ton CKD produced).

(12) Annual organic carbon content of each raw material (wt-fraction, dry basis).

(13) Annual consumption of each raw material (dry basis).

(14) Number of times missing data procedures were used to determine the following information:

- (i) Clinker production (number of months).
- (ii) Carbonate contents of clinker (number of months).
- (iii) Non-calcined content of clinker (number of months).
- (iv) CKD not recycled to kiln (number of quarters).
- (v) Non-calcined content of CKD (number of quarters)
- (vi) Organic carbon contents of raw materials (number of times).
- (vii) Raw material consumption (number of months).

§98.87 Records that must be retained.

(a) If a CEMS is used to measure CO₂ emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.

(1) Documentation of monthly calculated kiln-specific clinker CO₂ emission factor.

(2) Documentation of quarterly calculated kiln-specific CKD CO₂ emission factor.

(3) Measurements, records and calculations used to determine reported parameters.

(b) If a CEMS is not used to measure CO₂ emissions, then in addition to the records required by §98.3(g), you

must retain the records specified in paragraphs (a) through (b) of this section for each portland cement manufacturing facility.

§98.88 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart I [RESERVED]

Subpart J [RESERVED]

Subpart K—Ferroalloy Production

§98.110 Definition of the source category.

The ferroalloy production source category consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

§98.111 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a ferroalloy production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.112 GHGs to report.

You must report:

(a) Process CO₂ emissions from each electric arc furnace (EAF) used for the production of any ferroalloy listed in §98.110.

(b) CO₂, CH₄, and N₂O emissions from each stationary combustion unit following the requirements of subpart C of this part. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources).

§98.113 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each EAF using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the annual process CO₂ emissions using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the annual process CO₂ emissions from EAFs by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and the applicable

requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report under this subpart the annual process CO₂ emissions from the EAFs using the carbon mass balance procedure specified in paragraphs (b) (2) (i) and (b) (2) (ii) of this section.

(i) For each EAF, determine the annual mass of carbon in each carbon-containing input and output material for the EAF and estimate annual process CO₂ emissions from the EAF using Equation K-1 of this section. Carbon-containing input materials include carbon electrodes and carbonaceous reducing agents. If you document that a specific input or output material contributes less than 1 percent of the total carbon into or out of the process, you do not have to include the material in your calculation using Equation K-1 of this section.

$$\begin{aligned}
E_{CO_2} = & \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^i (M_{\text{reducing agent } i} \times C_{\text{reducing agent } i}) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^m (M_{\text{electrode } m} \times C_{\text{electrode } m}) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^h (M_{\text{ore } h} \times C_{\text{ore } h}) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^j (M_{\text{flux } j} \times C_{\text{flux } j}) \\
& - \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^k (M_{\text{product outgoing } k} \times C_{\text{product outgoing } k}) \\
& - \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^l (M_{\text{non-product outgoing } l} \times C_{\text{non-product outgoing } l})
\end{aligned}
\tag{Eq. K-1}$$

Where:

- E_{CO_2} = Annual process CO₂ emissions from an individual EAF (metric tons).
 $44/12$ = Ratio of molecular weights, CO₂ to carbon.
 $2000/2205$ = Conversion factor to convert tons to metric tons.
 $M_{\text{reducing agent } i}$ = Annual mass of reducing agent i fed, charged, or otherwise introduced into the EAF (tons).
 $C_{\text{reducing agent } i}$ = Carbon content in reducing agent i (percent by weight, expressed as a decimal fraction).
 $M_{\text{electrode } m}$ = Annual mass of carbon electrode m consumed in the EAF (tons).
 $C_{\text{electrode } m}$ = Carbon content of the carbon electrode m (percent by weight, expressed as a decimal fraction).
 $M_{\text{ore } h}$ = Annual mass of ore h charged to the EAF (tons).
 $C_{\text{ore } h}$ = Carbon content in ore h (percent by weight, expressed as a decimal fraction).
 $M_{\text{flux } j}$ = Annual mass of flux material j fed, charged, or otherwise introduced into the EAF to facilitate slag formation (tons).

C_{flux_j}	=	Carbon content in flux material j (percent by weight, expressed as a decimal fraction).
$M_{product_k}$	=	Annual mass of alloy product k tapped from EAF (tons).
$C_{product_k}$	=	Carbon content in alloy product k . (percent by weight, expressed as a decimal fraction).
$M_{non-product\ outgoing_1}$	=	Annual mass of non-product outgoing material 1 removed from EAF (tons).
$C_{non-product\ outgoing_1}$	=	Carbon content in non-product outgoing material 1 (percent by weight, expressed as a decimal fraction).

(ii) Determine the combined annual process CO₂

emissions from the EAFs at your facility using Equation K-2 of this section.

$$CO_2 = \sum_1^k E_{CO_2_k} \quad (\text{Eq. K-2})$$

Where:

CO_2	=	Annual process CO ₂ emissions from EAFs at facility used for the production of any ferroalloy listed in §98.110 (metric tons).
$E_{CO_2_k}$	=	Annual process CO ₂ emissions calculated from EAF k calculated using Equation K-1 of this section (metric tons).
k	=	Total number of EAFs at facility used for the production of any ferroalloy listed in §98.110.

(c) If GHG emissions from an EAF are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section

shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(d) For the EAFs at your facility used for the production of any ferroalloy listed in Table K-1 of this subpart, you must calculate and report the annual CH₄ emissions using the procedure specified in paragraphs (d)(1) and (2) of this section.

(1) For each EAF, determine the annual CH₄ emissions using Equation K-3 of this section.

$$E_{CH_4} = \sum_1^i (M_{product_i} \times \frac{2000}{2205} \times EF_{product_i}) \quad (\text{Eq. K-3})$$

Where:

E_{CH_4} = Annual process CH₄ emissions from an individual EAF (metric tons).
 $M_{product_i}$ = Annual mass of alloy product *i* produced in the EAF (tons).
 2000/2205 = Conversion factor to convert tons to metric tons.
 $EF_{product_i}$ = CH₄ emission factor for alloy product *i* from Table K-1 in this subpart (kg of CH₄ emissions per metric ton of alloy product *i*).

(2) Determine the combined process CH₄ emissions from the EAFs at your facility using Equation K-4 of this section:

$$CH_4 = \sum_1^j E_{CH_4j} \quad (\text{Eq. K-4})$$

Where:

- CH₄ = Annual process CH₄ emissions from EAFs at facility used for the production of ferroalloys listed in Table K-1 of this subpart (metric tons).
- E_{CH₄_j} = Annual process CH₄ emissions from EAF *j* calculated using Equation K-3 of this section (metric tons).
- j* = Total number of EAFs at facility used for the production of ferroalloys listed in Table K-1 of this subpart.

§98.114 Monitoring and QA/QC requirements.

If you determine annual process CO₂ emissions using the carbon mass balance procedure in §98.113(b)(2), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO₂ emissions using Equation K-1 of this subpart by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed, used, or produced in the calendar

year using the methods specified in either paragraph (b) (1) or (b) (2) of this section. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material inputs and outputs each year. The carbon content of the material must be analyzed at least annually using the standard methods (and their QA/QC procedures) specified in paragraphs (b) (2) (i) through (b) (2) (iii) of this section, as applicable.

(i) ASTM E1941-04, Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see §98.7) for analysis of metal ore and alloy product.

(ii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7), for analysis of carbonaceous reducing agents and carbon electrodes.

(iii) ASTM C25-06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime

(incorporated by reference, see §98.7) for analysis of flux materials such as limestone or dolomite.

§98.115 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.113 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) If you determine CO₂ emissions for the EAFs at your facility using the carbon mass balance procedure in §98.113(b), 100 percent data availability is required for the carbon content of the input and output materials. You must repeat the test for average carbon contents of inputs according to the procedures in §98.114(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of the inputs and outputs from on all available process data or data used for accounting purposes, such as purchase records.

(c) If you are required to calculate CH₄ emissions for an EAF at your facility as specified in §98.113(d), the estimate is based on an annual quantity of certain alloy products, so 100 percent data availability is required.

§98.116 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section, as applicable:

(a) Annual facility ferroalloy product production capacity (tons).

(b) Annual production for each ferroalloy product (tons) identified in §98.110, as applicable.

(c) Total number of EAFs at facility used for production of ferroalloy products reported in paragraph (a) (4) of this section.

(d) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required by §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (d) (1) through (d) (3) of this section.

(1) Annual process CO₂ emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart (metric tons).

(2) Annual process CH₄ emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart (metric tons).

(3) Identification number of each EAF.

(e) If a CEMS is not used to measure CO₂ process emissions, and the carbon mass balance procedure is used to determine CO₂ emissions according to the requirements in §98.113(b), then you must report the following information specified in paragraphs (e)(1) through (e)(7) of this section.

(1) Annual process CO₂ emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart (metric tons).

(2) Annual process CH₄ emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart (metric tons).

(3) Identification number of each EAF.

(4) Annual material quantity for each material included for the calculation of annual process CO₂ emissions for each EAF.

(5) Annual average of the carbon content determinations for each material included for the calculation of annual process CO₂ emissions for each EAF (percent by weight, expressed as a decimal fraction).

(6) List the method used for the determination of carbon content for each material reported in paragraph (e) (5) of this section (e.g., supplier provided information, analyses of representative samples you collected).

(7) If you use the missing data procedures in §98.115(b), you must report how monthly mass of carbon-containing inputs and outputs with missing data was determined and the number of months the missing data procedures were used.

§98.117 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section for each EAF, as applicable.

(a) If a CEMS is used to measure CO₂ emissions according to the requirements in §98.113(a), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Monthly EAF production quantity for each ferroalloy product (tons).

(2) Number of EAF operating hours each month.

(3) Number of EAF operating hours in a calendar year.

(b) If the carbon mass balance procedure is used to determine CO₂ emissions according to the requirements in §98.113(b)(2), then you must retain records for the information specified in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly EAF production quantity for each ferroalloy product (tons).

(2) Number of EAF operating hours each month.

(3) Number of EAF operating hours in a calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO₂ emissions (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO₂ emissions.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input and output to each EAF, including documentation of specific input or output materials excluded from Equation K-1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of

materials fed, charged, or placed in an EAF including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(d) If you are required to calculate CH₄ emissions for the EAF as specified in §98.113(d), you must maintain records of the total amount of each alloy product produced for the specified reporting period, and the appropriate alloy-product specific emission factor used to calculate the CH₄ emissions.

§98.118 Definitions.

All terms used of this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table K-1 of Subpart K—Electric Arc Furnace (EAF) CH₄ Emission Factors.

Alloy product produced in EAF	CH ₄ Emission Factor (kg CH ₄ per metric ton product)		
	EAF Operation		
	Batch-Charging	Sprinkle-Charging ^a	Sprinkle-Charging and >750 °C ^b
Silicon metal	1.5	1.2	0.7
Ferrosilicon 90%	1.4	1.1	0.6
Ferrosilicon 75%	1.3	1.0	0.5
Ferrosilicon 65%	1.3	1.0	0.5

^a Sprinkle-charging is charging intermittently every minute.

^b Temperature measured in off-gas channel downstream of the furnace hood.

Subpart L [RESERVED]

Subpart M [RESERVED]**Subpart N—Glass Production**§98.140 Definition of the source category.

(a) A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more continuous glass melting furnaces to produce glass.

(b) A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§98.141 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a glass production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.142 GHGs to report.

You must report:

(a) CO₂ process emissions from each continuous glass melting furnace.

(b) CO₂ combustion emissions from each continuous glass melting furnace.

(c) CH₄ and N₂O combustion emissions from each continuous glass melting furnace. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit other than continuous glass melting furnaces. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.143 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each continuous glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each continuous glass melting furnace that meets the conditions specified in §98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each continuous glass melting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO₂ emissions from the glass melting furnace by using either the procedure in paragraph (b) (1) of this section or the procedure in paragraphs (b) (2) through (b) (7) of this section, except as specified in paragraph (c) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a) (4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report the process and combustion CO₂ emissions separately using the procedures specified in paragraphs (b) (2) (i) through (b) (2) (vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table N-1 to this subpart.

(iv) Use Equation N-1 of this section to calculate process mass emissions of CO₂ for each furnace:

$$E_{\text{CO}_2} = \sum_{i=1}^n \text{MF}_i \cdot (M_i \cdot \frac{2000}{2205}) \cdot \text{EF}_i \cdot F_i \quad (\text{Eq. N-1})$$

Where:

E_{CO_2}	=	Process emissions of CO ₂ from the furnace (metric tons).
n	=	Number of carbonate-based raw materials charged to furnace.
MF_i	=	Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (percentage, expressed as a decimal).
M_i	=	Annual amount of carbonate-based raw material i charged to furnace (tons).
2000/2205	=	Conversion factor to convert tons to metric tons.
EF_i	=	Emission factor for carbonate-based raw material i (metric ton CO ₂ per metric ton carbonate-based raw material as shown in Table N-1 to this subpart).
F_i	=	Fraction of calcination achieved for carbonate-based raw material i , assumed to be equal to 1.0 (percentage, expressed as a decimal).

(v) You must calculate the total process CO₂ emissions from continuous glass melting furnaces at the facility using Equation N-2 of this section:

$$CO_2 = \sum_{i=1}^k E_{CO_2i} \quad (\text{Eq. N-2})$$

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (metric tons).

E_{CO_2i} = Annual CO_2 emissions from glass melting furnace i (metric tons).

k = Number of continuous glass melting furnaces.

(vi) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in subpart C.

(c) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the mass fraction (MF_i) of carbonate-based mineral i in Equation N-1 of this section.

§98.144 Monitoring and QA/QC requirements.

(a) You must measure annual amounts of carbonate-based raw materials charged to each continuous glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction

data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682-01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see §98.7).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§98.145 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in §98.144 cannot be followed

and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

§98.146 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable.

(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required under §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a) (1) and (a) (2) of this section:

(1) Annual quantity of each carbonate-based raw material charged to each continuous glass melting furnace and for all furnaces combined (tons).

(2) Annual quantity of glass produced (tons).

(b) If a CEMS is not used to determine CO₂ emissions from continuous glass melting furnaces, and process CO₂ emissions are calculated according to the procedures specified in §98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (b)(9) of this section:

(1) Annual process emissions of CO₂ (metric tons) for each continuous glass melting furnace and for all furnaces combined.

(2) Annual quantity of each carbonate-based raw material charged (tons) to each continuous glass melting furnace and for all furnaces combined.

(3) Annual quantity of glass produced (tons) from each continuous glass melting furnace and from all furnaces combined.

(4) Carbonate-based mineral mass fraction (percentage, expressed as a decimal) for each carbonate-based raw material charged to a continuous glass melting furnace.

(5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, as specified in paragraphs (b) (5) (i) through (b) (5) (iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(6) The fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO₂.

(7) Method used to determine fraction of calcination (percentage, expressed as a decimal).

(8) Total number of continuous glass melting furnaces.

(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials any continuous glass melting furnace or mass fraction of the carbonate-based minerals (months).

§98.147 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records listed in paragraphs (a), (b), and (c) of this section.

(a) If a CEMS is used to measure emissions, then you must retain the records required under §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Monthly glass production rate for each continuous glass melting furnace (tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (tons).

(b) If process CO₂ emissions are calculated according to the procedures specified in §98.143(b), you must retain the records in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly glass production rate for each continuous glass melting furnace (metric tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (metric tons).

(3) Data on carbonate-based mineral mass fractions provided by the raw material supplier for all raw materials

consumed annually and included in calculating process emissions in Equation N-1 of this subpart.

(4) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, including the data specified in paragraphs (b) (4) (i) through (b) (4) (v) of this section.

(i) Date of test.

(ii) Method(s), and any variations of the methods, used in the analyses.

(iii) Mass fraction of each sample analyzed.

(iv) Relevant calibration data for the instrument(s) used in the analyses.

(v) Name and address of laboratory that conducted the tests.

(5) The fraction of calcination achieved for each carbonate-based raw material (percentage, expressed as a decimal), if a value other than 1.0 is used to calculate process mass emissions of CO₂.

(c) All other documentation used to support the reported GHG emissions.

§98.148 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table N-1 of Subpart N-CO₂ Emission Factors for Carbonate-Based Raw Materials

Carbonate-Based Raw Material - Mineral	CO ₂ Emission Factor ^a
Limestone - CaCO ₃	0.440
Dolomite - CaMg(CO ₃) ₂	0.477
Sodium carbonate/soda ash - Na ₂ CO ₃	0.415

^a Emission factors in units of metric tons of CO₂ emitted per metric ton of carbonate-based raw material charged to the furnace.

Subpart O-HCFC-22 Production and HFC-23 Destruction§98.150 Definition of the source category.

The HCFC-22 production and HFC-23 destruction source category consists of HCFC-22 production processes and HFC-23 destruction processes.

(a) An HCFC-22 production process produces HCFC-22 (chlorodifluoromethane, or CHClF₂) from chloroform (CHCl₃) and hydrogen fluoride (HF).

(b) An HFC-23 destruction process is any process in which HFC-23 undergoes destruction. An HFC-23 destruction process may or may not be co-located with an HCFC-22 production process at the same facility.

§98.151 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a HCFC-22 production or HFC-23 destruction process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.152 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C.

(b) You must report HFC-23 emissions from HCFC-22 production processes and HFC-23 destruction processes.

§98.153 Calculating GHG emissions.

(a) The mass of HFC-23 generated from each HCFC-22 production process shall be estimated by using one of two methods, as applicable:

(1) Where the mass flow of the combined stream of HFC-23 and another reaction product (e.g., HCl) is measured, multiply the weekly (or more frequent) HFC-23 concentration measurement (which may be the average of more frequent concentration measurements) by the weekly (or more frequent) mass flow of the combined stream of HFC-23 and the other product. To estimate annual HFC-23 production, sum the weekly (or more frequent) estimates of the quantities of HFC-23 produced over the year. This calculation is summarized in Equation O-1 of this section:

$$G_{23} = \sum_{p=1}^n c_{23} * F_p * 10^{-3} \quad (\text{Eq. O-1})$$

Where:

G_{23} = Mass of HFC-23 generated annually (metric tons).

- C_{23} = Fraction HFC-23 by weight in HFC-23/other product stream.
- F_p = Mass flow of HFC-23/other product stream during the period p (kg).
- p = Period over which mass flows and concentrations are measured.
- n = Number of concentration and flow measurement periods for the year.
- 10^{-3} = Conversion factor from kilograms to metric tons.

(2) Where the mass of only a reaction product other than HFC-23 (either HCFC-22 or HCl) is measured, multiply the ratio of the weekly (or more frequent) measurement of the HFC-23 concentration and the weekly (or more frequent) measurement of the other product concentration by the weekly (or more frequent) mass produced of the other product. To estimate annual HFC-23 production, sum the weekly (or more frequent) estimates of the quantities of HFC-23 produced over the year. This calculation is summarized in Equation O-2 of this section, assuming that the other product is HCFC-22. If the other product is HCl, HCl may be substituted for HCFC-22 in Equations O-2 and O-3 of this section.

$$G_{23} = \sum_{p=1}^n \left(\frac{C_{23}}{C_{22}} \right) * P_{22} * 10^{-3} \quad (\text{Eq. O-2})$$

Where:

- G_{23} = Mass of HFC-23 generated annually (metric tons).
- C_{23} = Fraction HFC-23 by weight in HCFC-22/HFC-23 stream.

C_{22}	=	Fraction HCFC-22 by weight in HCFC-22/HFC-23 stream.
P_{22}	=	Mass of HCFC-22 produced over the period p (kg), calculated using Equation O-3 of this section.
p	=	Period over which masses and concentrations are measured.
n	=	Number of concentration and mass measurement periods for the year.
10^{-3}	=	Conversion factor from kilograms to metric tons.

(b) The mass of HCFC-22 produced over the period p shall be estimated by using Equation O-3 of this section:

$$P_{22} = LF * (O_{22} - U_{22}) \quad (\text{Eq. O-3})$$

Where:

P_{22}	=	Mass of HCFC-22 produced over the period p (kg).
O_{22}	=	mass of HCFC-22 that is measured coming out of the Production process over the period p (kg).
U_{22}	=	Mass of used HCFC-22 that is added to the production process upstream of the output measurement over the period p (kg).
LF	=	Factor to account for the loss of HCFC-22 upstream of the measurement. The value for LF shall be determined pursuant to §98.154(e).

(c) For HCFC-22 production facilities that do not use a thermal oxidizer or that have a thermal oxidizer that is not directly connected to the HCFC-22 production equipment, HFC-23 emissions shall be estimated using Equation O-4 of this section:

$$E_{23} = G_{23} - (S_{23} + OD_{23} + D_{23} + I_{23}) \quad (\text{Eq. O-4})$$

Where:

E_{23}	=	Mass of HFC-23 emitted annually (metric tons).
G_{23}	=	Mass of HFC-23 generated annually (metric tons).

S_{23}	=	Mass of HFC-23 sent off site for sale annually (metric tons).
OD_{23}	=	Mass of HFC-23 sent off site for destruction (metric tons).
D_{23}	=	Mass of HFC-23 destroyed on site (metric tons).
I_{23}	=	Increase in HFC-23 inventory = HFC-23 in storage at end of year - HFC-23 in storage at beginning of year (metric tons).

(d) For HCFC-22 production facilities that use a thermal oxidizer connected to the HCFC-22 production equipment, HFC-23 emissions shall be estimated using Equation O-5 of this section:

$$E_{23} = E_L + E_{PV} + E_D \quad (\text{Eq. O-5})$$

Where:

E_{23}	=	Mass of HFC-23 emitted annually (metric tons).
E_L	=	Mass of HFC-23 emitted annually from equipment leaks, calculated using Equation O-6 of this section (metric tons).
E_{PV}	=	Mass of HFC-23 emitted annually from process vents, calculated using Equation O-7 of this section (metric tons).
E_D	=	Mass of HFC-23 emitted annually from thermal oxidizer (metric tons), calculated using Equation O-8 of this section.

(1) The mass of HFC-23 emitted annually from equipment leaks (for use in Equation O-5 of this section) shall be estimated by using Equation O-6 of this section:

$$E_L = \sum_{p=1}^n \sum_t c_{23} * (F_{Gt} * N_{Gt} + F_{Lt} * N_{Lt}) * 10^{-3} \quad (\text{Eq. O-6})$$

Where:

E_L	=	Mass of HFC-23 emitted annually from equipment leaks (metric tons).
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- C_{23} = Fraction HFC-23 by weight in the stream(s) in the equipment.
- F_{Gt} = The applicable leak rate specified in Table O-1 of this subpart for each source of equipment type and service t with a screening value greater than or equal to 10,000 ppmv (kg/hr/source).
- N_{Gt} = The number of sources of equipment type and service t with screening values greater than or equal to 10,000 ppmv as determined according to §98.154(i).
- F_{Lt} = The applicable leak rate specified in Table O-1 of this subpart for each source of equipment type and service t with a screening value of less than 10,000 ppmv (kg/hr/source).
- N_{Lt} = The number of sources of equipment type and service t with screening values less than 10,000 ppmv as determined according to §98.154(j).
- p = One hour.
- n = Number of hours during the year during which equipment contained HFC-23.
- t = Equipment type and service as specified in Table O-1 of this subpart .
- 10^{-3} = Factor converting kg to metric tons.
- (2) The mass of HFC-23 emitted annually from process

vents (for use in Equation O-5 of this section) shall be estimated by using Equation O-7 of this section:

$$E_{PV} = \sum_{p=1}^n ER_T * \left(\frac{PR_p}{PR_T} \right) * l_p * 10^{-3} \quad (\text{Eq. O-7})$$

Where:

- E_{PV} = Mass of HFC-23 emitted annually from process vents (metric tons).
- ER_T = The HFC-23 emission rate from the process vents during the period of the most recent test (kg/hr).
- PR_p = The HCFC-22 production rate during the period p (kg/hr).
- PR_T = The HCFC-22 production rate during the most recent test period (kg/hr).

l_p = The length of the period p (hours).
 10^{-3} = Factor converting kg to metric tons.
 n = The number of periods in a year.

(3) The total mass of HFC-23 emitted from destruction devices shall be estimated by using Equation O-8 of this section:

$$E_D = F_D - D_{23} \quad (\text{Eq. O-8})$$

Where:

E_D = Mass of HFC-23 emitted annually from the destruction device (metric tons).
 F_D = Mass of HFC-23 fed into the destruction device annually (metric tons).
 D_{23} = Mass of HFC-23 destroyed annually (metric tons).

(4) For facilities that destroy HFC-23, the total mass of HFC-23 destroyed shall be estimated by using Equation O-9 of this section:

$$D_{23} = F_D * DE \quad (\text{Eq. O-9})$$

Where:

D_{23} = Mass of HFC-23 destroyed annually (metric tons).
 F_D = Mass of HFC-23 fed into the destruction device annually (metric tons).
 DE = Destruction Efficiency of the destruction device (fraction).

§98.154 Monitoring and QA/QC requirements.

These requirements apply to measurements that are reported under this subpart or that are used to estimate reported quantities pursuant to §98.153.

(a) The concentrations (fractions by weight) of HFC-23 and HCFC-22 in the product stream shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(b) The mass flow of the product stream containing the HFC-23 shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(c) The mass of HCFC-22 or HCl coming out of the production process shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(d) The mass of any used HCFC-22 added back into the production process upstream of the output measurement in paragraph (c) of this section shall be measured (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the mass in paragraph (c) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall

be considered used fluorinated HCFC-22 for purposes of this paragraph (d) of this section and §98.153(b).

(e) The loss factor LF in Equation O-3 of this subpart for the mass of HCFC-22 produced shall have the value 1.015 or another value that can be demonstrated, to the satisfaction of the Administrator, to account for losses of HCFC-22 between the reactor and the point of measurement at the facility where production is being estimated.

(f) The mass of HFC-23 sent off site for sale shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(g) The mass of HFC-23 sent off site for destruction shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC-23, the concentration of the fluorinated GHG shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the

concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC-23 sent to another facility for destruction.

(h) The masses of HFC-23 in storage at the beginning and end of the year shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(i) The number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv shall be determined using EPA Method 21 at 40 CFR part 60, appendix A-7, and defining a leak as follows:

- (1) A leak source that could emit HFC-23, and
- (2) A leak source at whose surface a concentration of fluorocarbons equal to or greater than 10,000 ppm is measured.

(j) The number of sources of equipment type t with screening values less than 10,000 ppmv shall be the difference between the number of leak sources of equipment type t that could emit HFC-23 and the number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv as determined under paragraph (h) of this section.

(k) The mass of HFC-23 emitted from process vents shall be estimated at least monthly by incorporating the results of the most recent emissions test into Equation O-6 of this subpart. HCFC-22 production facilities that use a thermal oxidizer connected to the HCFC-22 production equipment shall conduct emissions tests at process vents at least once every five years or after significant changes to the process. Emissions tests shall be conducted in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6, under conditions that are typical for the production process at the facility. The sensitivity of the tests shall be sufficient to detect an emission rate that would result in annual emissions of 200 kg of HFC-23 if sustained over one year.

(l) For purposes of Equation O-9 of this subpart, the destruction efficiency must be equated to the destruction efficiency determined during a new or previous performance test of the destruction device. HFC-23 destruction facilities shall conduct annual measurements of HFC-23 concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6. Three samples shall be taken under conditions that are typical for the production process and destruction device at the facility, and the average concentration of HFC-23

shall be determined. The sensitivity of the concentration measurement shall be sufficient to detect an outlet concentration equal to or less than the outlet concentration determined in the destruction efficiency performance test. If the concentration measurement indicates that the HFC-23 concentration is less than or equal to that measured during the performance test that is the basis for the destruction efficiency, continue to use the previously determined destruction efficiency. If the concentration measurement indicates that the HFC-23 concentration is greater than that measured during the performance test that is the basis for the destruction efficiency, facilities shall either:

(1) Substitute the higher HFC-23 concentration for that measured during the destruction efficiency performance test and calculate a new destruction efficiency, or

(2) Estimate the mass emissions of HFC-23 from the destruction device based on the measured HFC-23 concentration and volumetric flow rate determined by measurement of volumetric flow rate using EPA Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1, or Method 26 at 40 CFR part 60, appendix A-2. Determine the mass rate of HFC-23 into the destruction device by measuring the HFC-23 concentration and volumetric flow rate at the inlet or

by a metering device for HFC-23 sent to the device.

Determine a new destruction efficiency based on the mass flow rate of HFC-23 into and out of the destruction device.

(m) HCFC-22 production facilities shall account for HFC-23 generation and emissions that occur as a result of startups, shutdowns, and malfunctions, either recording HFC-23 generation and emissions during these events, or documenting that these events do not result in significant HFC-23 generation and/or emissions.

(n) The mass of HFC-23 fed into the destruction device shall be measured at least weekly using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC-23, the concentrations of the HFC-23 shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC-23 destroyed.

(o) In their estimates of the mass of HFC-23 destroyed, HFC-23 destruction facilities shall account for

any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(p) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures using NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others). Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer.

(q) All gas chromatographs used to determine the concentration of HFC-23 in process streams shall be calibrated at least monthly through analysis of certified standards (or of calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205 at 40 CFR part 51, appendix M) with known HFC-23 concentrations that are in the same range (fractions by mass) as the process samples.

§98.155 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore,

whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required process sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(1) For each missing value of the HFC-23 or HCFC-22 concentration, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For each missing value of the product stream mass flow or product mass, the substitute value of that parameter shall be a secondary product measurement where such a measurement is available. If that measurement is taken significantly downstream of the usual mass flow or mass measurement (e.g., at the shipping dock rather than near the reactor), the measurement shall be multiplied by 1.015 to compensate for losses. Where a secondary mass measurement is not available, the substitute value of the

parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§98.156 Data reporting requirements.

(a) In addition to the information required by §98.3(c), the HCFC-22 production facility shall report the following information at the facility level:

(1) Annual mass of HCFC-22 produced in metric tons.

(2) Loss Factor used to account for the loss of HCFC-22 upstream of the measurement.

(3) Annual mass of reactants fed into the process in metric tons of reactant.

(4) The mass (in metric tons) of materials other than HCFC-22 and HFC-23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process.

(5) The method for tracking startups, shutdowns, and malfunctions and HFC-23 generation/emissions during these events.

(6) The names and addresses of facilities to which any HFC-23 was sent for destruction, and the quantities of HFC-23 (metric tons) sent to each.

(7) Annual mass of the HFC-23 generated in metric tons.

(8) Annual mass of any HFC-23 sent off site for sale in metric tons.

(9) Annual mass of any HFC-23 sent off site for destruction in metric tons.

(10) Mass of HFC-23 in storage at the beginning and end of the year, in metric tons.

(11) Annual mass of HFC-23 emitted in metric tons.

(12) Annual mass of HFC-23 emitted from equipment leaks in metric tons.

(13) Annual mass of HFC-23 emitted from process vents in metric tons.

(b) In addition to the information required by §98.3(c), facilities that destroy HFC-23 shall report the following for each HFC-23 destruction process:

(1) Annual mass of HFC-23 fed into the thermal oxidizer.

(2) Annual mass of HFC-23 destroyed.

(3) Annual mass of HFC-23 emitted from the thermal oxidizer.

(c) Each HFC-23 destruction facility shall report the results of the facility's annual HFC-23 concentration measurements at the outlet of the destruction device, including:

(1) Flow rate of HFC-23 being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of HFC-23 at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(d) Emission rate calculated from paragraphs (c) (2) and (3) of this section in kg/hr.

(e) HFC-23 destruction facilities shall submit a one-time report including the following information for each the destruction process:

(1) Destruction efficiency (DE).

(2) The methods used to determine destruction efficiency.

(3) The methods used to record the mass of HFC-23 destroyed.

(4) The name of other relevant federal or state regulations that may apply to the destruction process.

(5) If any changes are made that affect HFC-23 destruction efficiency or the methods used to record volume

destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change.

§98.157 Records that must be retained.

(a) In addition to the data required by §98.3(g), HCFC-22 production facilities shall retain the following records:

(1) The data used to estimate HFC-23 emissions.

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this rule, including the industry standards or manufacturer directions used for calibration pursuant to §98.154(p) and (q).

(b) In addition to the data required by §98.3(g), the HFC-23 destruction facilities shall retain the following records:

(1) Records documenting their one-time and annual reports in §98.156(b) through (d).

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this subpart, including the industry standard practice or manufacturer

directions used for calibration pursuant to §98.154(p) and (q).

§98.158 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table O-1 of Subpart O—Emission Factors for Equipment Leaks

Equipment Type	Service	Emission Factor (kg/hr/source)	
		≥10,000 ppmv	<10,000 ppmv
Valves	Gas	0.0782	0.000131
Valves	Light liquid	0.0892	0.000165
Pump seals	Light liquid	0.243	0.00187
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.113	0.0000810
Open-ended lines	All	0.01195	0.00150

Subpart P—Hydrogen Production

§98.160 Definition of the source category.

(a) A hydrogen production source category consists of facilities that produce hydrogen gas sold as a product to other entities.

(b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes merchant hydrogen production facilities located within a petroleum refinery if they are not owned by, or under the direct control of, the refinery owner and operator.

§98.161 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a hydrogen production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.162 GHGs to report.

You must report:

(a) CO₂ process emissions from each hydrogen production process unit.

(b) CO₂, CH₄ and N₂O combustion emissions from each hydrogen production process unit. You must calculate and report these combustion emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(c) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than hydrogen production process units. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) For CO₂ collected and transferred off site, you must follow the requirements of subpart PP of this part.

§98.163 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each hydrogen production process unit using

the procedures specified in either paragraph (a) or (b) of this section.

(a) Continuous Emissions Monitoring Systems (CEMS).

Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a) (4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Fuel and feedstock material balance approach.

Calculate and report process CO₂ emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b) (1) through (b) (3) of this section.

(1) Gaseous fuel and feedstock. You must calculate the annual CO₂ process emissions from gaseous fuel and feedstock according to Equation P-1 of this section:

$$CO_2 = \left(\sum_{n=1}^k \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC} \right) * 0.001 \quad (\text{Eq. P-1})$$

Where:

CO₂ = Annual CO₂ process emissions arising from fuel and feedstock consumption (metric tons/yr).

Fdstk_n = Volume of the gaseous fuel and feedstock used in month n (scf (at standard conditions of 68 °F and atmospheric pressure) of fuel and feedstock).

CC_n	=	Average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n (kg carbon per kg of fuel and feedstock).
MW	=	Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon. 0.001=Conversion factor from kg to metric tons.

(2) Liquid fuel and feedstock. You must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation P-2 of this section:

$$CO_2 = \left(\sum_{n=1}^k \frac{44}{12} * Fdstk_n * CC_n \right) * 0.001 \quad (\text{Eq. P-2})$$

Where:

CO_2	=	Annual CO_2 emissions arising from fuel and feedstock consumption (metric tons/yr).
$Fdstk_n$	=	Volume of the liquid fuel and feedstock used in month n (gallons of fuel and feedstock).
CC_n	=	Average carbon content of the liquid fuel and feedstock, from the results of one or more analyses for month n (kg carbon per gallon of fuel and feedstock).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(3) Solid fuel and feedstock. You must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation P-3 of this section:

$$CO_2 = \left(\sum_{n=1}^k \frac{44}{12} * Fdstk_n * CC_n \right) * 0.001 \quad (\text{Eq. P-3})$$

Where:

- CO₂ = Annual CO₂ emissions from fuel and feedstock consumption in metric tons per month (metric tons/yr).
- Fdstk_n = Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).
- CC_n = Average carbon content of the solid fuel and feedstock, from the results of one or more analyses for month n (kg carbon per kg of fuel and feedstock).
- k = Months in the year.
- 44/12 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to metric tons.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§98.164 Monitoring and QA/QC requirements.

The GHG emissions data for hydrogen production process units must be quality-assured as specified in paragraphs (a) or (b) of this section, as appropriate for each process unit:

(a) If a CEMS is used to measure GHG emissions, then the facility must comply with the monitoring and QA/QC procedures specified in §98.34(c).

(b) If a CEMS is not used to measure GHG emissions, then you must:

(1) Calibrate all oil and gas flow meters (except for gas billing meters), solids weighing equipment, and oil tank drop measurements (if used to determine liquid fuel and feedstock use volume) according to the calibration accuracy requirements in §98.3(i) of this part .

(2) Determine the carbon content and the molecular weight annually of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (e.g., natural gas). For other gaseous fuels and feedstocks (e.g., biogas, refinery gas, or process gas), weekly sampling and analysis is required to determine the carbon content and molecular weight of the fuel and feedstock.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least monthly, except annually for standard liquid hydrocarbon

fuels and feedstocks having consistent composition, or upon delivery for liquid fuels delivered by bulk transport (e.g., by truck or rail).

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least monthly, except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels delivered by bulk transport (e.g., by truck or rail).

(5) You must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2013-07 Standard Practice of Preparing Coal Samples for Analysis (incorporated by reference, see §98.7).

(iv) ASTM D2234/D2234M-07 Standard Practice for Collection of a Gross Sample of Coal (incorporated by reference, see §98.7).

(v) ASTM D2597-94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography (incorporated by reference, see §98.7).

(vi) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

(vii) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(viii) ASTM D4057-06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference, see §98.7).

(ix) ASTM D4177-95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products (incorporated by reference, see §98.7).

(x) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(xi) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and

Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(xii) ASTM D6609-08 Standard Guide for Part-Stream Sampling of Coal (incorporated by reference, see §98.7).

(xiii) ASTM D6883-04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles (incorporated by reference, see §98.7).

(xiv) ASTM D7430-08a¹ Standard Practice for Mechanical Sampling of Coal (incorporated by reference, see §98.7).

(xv) ASTM UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(xvi) GPA 2261-00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(xvii) ISO 3170: Petroleum Liquids -- Manual sampling - Third Edition (incorporated by reference, see §98.7).

(xviii) ISO 3171: Petroleum Liquids -- Automatic pipeline sampling - Second Edition (incorporated by reference, see §98.7).

(c) For units using the calculation methodologies described in this section, the records required under §98.3(g) must include both the company records and a

detailed explanation of how company records are used to estimate the following:

(1) Fuel and feedstock consumption, when solid fuel and feedstock is combusted and a CEMS is not used to measure GHG emissions.

(2) Fossil fuel consumption, when, pursuant to §98.33(e), the owner or operator of a unit that uses CEMS to quantify CO₂ emissions and that combusts both fossil and biogenic fuels separately reports the biogenic portion of the total annual CO₂ emissions.

(3) Sorbent usage, if the methodology in §98.33(d) is used to calculate CO₂ emissions from sorbent.

(d) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel and feedstock usage and sorbent usage (as applicable) in paragraph (b) of this section, including, but not limited to, calibration of weighing equipment, fuel and feedstock flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.165 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore,

whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after

the missing data period. You must document and keep records of the procedures used for all such estimates.

(c) For missing CEMS data, you must use the missing data procedures in §98.35.

§98.166 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate:

(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Unit identification number and annual CO₂ process emissions.

(2) Annual quantity of hydrogen produced (metric tons) for each process unit and for all units combined.

(3) Annual quantity of ammonia produced (metric tons), if applicable, for each process unit and for all units combined.

(b) If a CEMS is not used to measure CO₂ emissions, then you must report the following information for each hydrogen production process unit:

(1) Unit identification number and annual CO₂ process emissions (2) Monthly consumption of each fuel and

feedstock used for hydrogen production and its type (scf of gaseous fuels and feedstocks, gallons of liquid fuels and feedstocks, kg of solid fuels and feedstocks).

(3) Annual quantity of hydrogen produced (metric tons).

(4) Annual quantity of ammonia produced, if applicable (metric tons).

(5) Monthly analyses of carbon content for each fuel and feedstock used in hydrogen production (kg carbon/kg of gaseous and solid fuels and feedstocks, (kg carbon per gallon of liquid fuels and feedstocks).

(6) Monthly analyses of the molecular weight of gaseous fuels and feedstocks (kg/kg-mole) used, if any.

(c) Quarterly quantity of CO₂ collected and transferred off site in either gas, liquid, or solid forms (kg), following the requirements of subpart PP of this part.

(d) Annual quantity of carbon other than CO₂ collected and transferred off site in either gas, liquid, or solid forms (kg carbon).

§98.167 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a)

through (b) of this section for each hydrogen production facility.

(a) If a CEMS is used to measure CO₂ emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.

(b) If a CEMS is not used to measure CO₂ emissions, then you must retain records of all analyses and calculations conducted as listed in §§98.166(b), (c), and (d).

§98.168 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Q—Iron and Steel Production

§98.170 Definition of the source category.

The iron and steel production source category includes facilities with any of the following processes: taconite iron ore processing, integrated iron and steel manufacturing, cokemaking not colocated with an integrated iron and steel manufacturing process, and electric arc furnace (EAF) steelmaking not colocated with an integrated iron and steel manufacturing process. Integrated iron and steel manufacturing means the production of steel from iron ore or iron ore pellets. At a minimum, an integrated iron and steel manufacturing process has a basic oxygen furnace

for refining molten iron into steel. Each cokemaking process and EAF process located at a facility with an integrated iron and steel manufacturing process is part of the integrated iron and steel manufacturing facility.

§98.171 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an iron and steel production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.172 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C except for flares. Stationary combustion units include, but are not limited to, by-product recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheat furnaces, annealing furnaces, flame suppression, ladle reheaters, and other miscellaneous combustion sources.

(b) You must report CO₂ emissions from flares according to the procedures in §98.253(b)(1) of subpart Y (Petroleum Refineries) of this part except you must use the default CO₂ emission factors for coke oven gas and blast

furnace gas from Table C-1 of subpart C in Equation Y-1 of subpart Y of this part. You must report CH₄ and N₂O emissions from flares according to the requirements in §98.33(c)(2) using the emission factors for coke oven gas and blast furnace gas in Table C-2 of subpart C of this part.

(c) You must report process CO₂ emissions from each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery combustion stack; coke pushing process; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace by following the procedures in this subpart.

§98.173 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace using the procedures in either paragraph (a) or (b) of this section. Calculate and report the annual process CO₂ emissions from the coke pushing process according to paragraph (c) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in

§98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions using the procedure in paragraph (b)(1) or (b)(2) of this section.

(1) Carbon mass balance method. Calculate the annual mass emissions of CO₂ for the process as specified in paragraphs (b)(1)(i) through (b)(1)(vii) of this section. The calculations are based on the annual mass of inputs and outputs to the process and an annual analysis of the respective weight fraction of carbon as determined according to the procedures in §98.174(b). If you have a process input or output other than CO₂ in the exhaust gas that contains carbon that is not included in Equations Q-1 through Q-7 of this section, you must account for the carbon and mass rate of that process input or output in your calculations according to the procedures in §98.174(b)(5).

(i) For taconite indurating furnaces, estimate CO₂ emissions using Equation Q-1 of this section.

$$CO_2 = \frac{44}{12} * [(F_s) * (C_s) + (F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (F_l) * (C_l) * 0.001 + (O) * (C_o) - (P) * (C_p) - (R) * (C_r)] \quad (\text{Eq. Q-1})$$

Where:

CO_2	=	Annual CO_2 mass emissions from the taconite indurating furnace (metric tons).
$44/12$	=	Ratio of molecular weights, CO_2 to carbon.
(F_s)	=	Annual mass of the solid fuel combusted (metric tons).
(C_{sf})	=	Carbon content of the solid fuel, from the fuel analysis (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
(F_g)	=	Annual volume of the gaseous fuel combusted (scf).
(C_{gf})	=	Average carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
0.001	=	Conversion factor from kg to metric tons.
(F_l)	=	Annual volume of the liquid fuel combusted (gallons).
(C_{lf})	=	Carbon content of the liquid fuel, from the fuel analysis results (kg C per gallon of fuel).
(O)	=	Annual mass of greenball (taconite) pellets fed to the furnace (metric tons).
(C_0)	=	Carbon content of the greenball (taconite) pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(P)	=	Annual mass of fired pellets produced by the furnace (metric tons).
(C_p)	=	Carbon content of the fired pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(R)	=	Annual mass of air pollution control residue collected (metric tons).
(C_R)	=	Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(ii) For basic oxygen process furnaces, estimate CO_2 emissions using Equation Q-2 of this section.

$$CO_2 = \frac{44}{12} * [(Iron) * (C_{Iron}) + (Scrap) * (C_{Scrap}) + (Flux) * (C_{Flux}) + (Carbon) * (C_{Carbon}) - (Steel) * (C_{Steel}) - (Slag) * (C_{Slag}) - (R) * (C_R)] \quad (\text{Eq. Q-2})$$

Where:

- CO₂ = Annual CO₂ mass emissions from the basic oxygen furnace (metric tons).
- 44/12 = Ratio of molecular weights, CO₂ to carbon.
- (Iron) = Annual mass of molten iron charged to the furnace (metric tons).
- (C_{Iron}) = Carbon content of the molten iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Scrap) = Annual mass of ferrous scrap charged to the furnace (metric tons).
- (C_{Scrap}) = Carbon content of the ferrous scrap, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Flux) = Annual mass of flux materials (e.g., limestone, dolomite) charged to the furnace (metric tons).
- (C_{Flux}) = Carbon content of the flux materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).
- (C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Steel) = Annual mass of molten raw steel produced by the furnace (metric tons).
- (C_{Steel}) = Carbon content of the steel, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Slag) = Annual mass of slag produced by the furnace (metric tons).
- (C_{Slag}) = Carbon content of the slag, from the carbon analysis (percent by weight, expressed as a decimal fraction).
- (R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(iii) For non-recovery coke oven batteries, estimate CO₂ emissions using Equation Q-3 of this section.

$$CO_2 = \frac{44}{12} * [(Coal) * (C_{Coal}) - (Coke) * (C_{Coke}) - (R) * (C_R)] \quad (\text{Eq. Q-3})$$

Where:

CO₂ = Annual CO₂ mass emissions from the non-recovery coke oven battery (metric tons).

44/12 = Ratio of molecular weights, CO₂ to carbon.

(Coal) = Annual mass of coal charged to the battery (metric tons).

(C_{Coal}) = Carbon content of the coal, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Coke) = Annual mass of coke produced by the battery (metric tons).

(C_{Coke}) = Carbon content of the coke, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(iv) For sinter processes, estimate CO₂ emissions using Equation Q-4 of this section.

$$CO_2 = \frac{44}{12} * [(F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (Feed) * (C_{Feed}) - (Sinter) * (C_{Sinter}) - (R) * (C_R)] \quad (\text{Eq. Q-4})$$

Where:

CO₂ = Annual CO₂ mass emissions from the sinter process (metric tons).

44/12	=	Ratio of molecular weights, CO ₂ to carbon.
(F _g)	=	Annual volume of the gaseous fuel combusted (scf).
(C _{gf})	=	Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
0.001	=	Conversion factor from kg to metric tons.
(Feed)	=	Annual mass of sinter feed material (metric tons).
(C _{Feed})	=	Carbon content of the mixed sinter feed materials that form the bed entering the sintering machine, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Sinter)	=	Annual mass of sinter produced (metric tons).
(C _{Sinter})	=	Carbon content of the sinter pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(R)	=	Annual mass of air pollution control residue collected (metric tons).
(C _R)	=	Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(v) For EAFs, estimate CO₂ emissions using Equation Q-5 of this section.

$$\begin{aligned}
 CO_2 = & \frac{44}{12} * [(Iron) * (C_{Iron}) + (Scrap) * (C_{Scrap}) + (Flux) \\
 & * (C_f) + (Electrode) * (C_{Electrode}) + (Carbon) * (C_c) - (Steel) \\
 & * (C_{Steel}) - (Slag) * (C_{Slag}) - (R) * (C_R)
 \end{aligned}
 \quad (\text{Eq. Q-5})$$

Where:

CO ₂	=	Annual CO ₂ mass emissions from the EAF (metric tons).
44/12	=	Ratio of molecular weights, CO ₂ to carbon.

(Iron)	= Annual mass of direct reduced iron (if any) charged to the furnace (metric tons).
(C _{Iron})	= Carbon content of the direct reduced iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Scrap)	= Annual mass of ferrous scrap charged to the furnace (metric tons).
(C _{Scrap})	= Carbon content of the ferrous scrap, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Flux)	= Annual mass of flux materials (e.g., limestone, dolomite) charged to the furnace (metric tons).
(C _{Flux})	= Carbon content of the flux materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Electrode)	= Annual mass of carbon electrode consumed (metric tons).
(C _{Electrode})	= Carbon content of the carbon electrode, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Carbon)	= Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).
(C _{Carbon})	= Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Steel)	= Annual mass of molten raw steel produced by the furnace (metric tons).
(C _{Steel})	= Carbon content of the steel, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(Slag)	= Annual mass of slag produced by the furnace (metric tons).
(C _{Slag})	= Carbon content of the slag, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
(R)	= Annual mass of air pollution control residue collected (metric tons).
(C _R)	= Carbon content of the air pollution control residue, from the carbon analysis results

(percent by weight, expressed as a decimal fraction).

(vi) For argon-oxygen decarburization vessels, estimate CO₂ emissions using Equation Q-6 of this section.

$$CO_2 = \frac{44}{12} * (Steel) * [(C_{Steelin}) - (C_{Steelout})] - (R) * (C_R) \quad (\text{Eq. Q-6})$$

Where:

CO₂ = Annual CO₂ mass emissions from the argon-oxygen decarburization vessel (metric tons).

44/12 = Ratio of molecular weights, CO₂ to carbon.

(Steel) = Annual mass of molten steel charged to the vessel (metric tons).

(C_{Steelin}) = Carbon content of the molten steel before decarburization, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(C_{Steelout}) = Carbon content of the molten steel after decarburization, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(vii) For direct reduction furnaces, estimate CO₂ emissions using Equation Q-7 of this section.

$$CO_2 = \frac{44}{12} * [(F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (Ore) * (C_{Ore}) + (Carbon) * (C_{Carbon}) + (Other) * (C_{Other}) - (Iron) * (C_{Iron}) - (NM) * (C_{NM}) - (R) * (C_R)] \quad (\text{Eq. Q-7})$$

Where:

CO₂ = Annual CO₂ mass emissions from the direct reduction furnace (metric tons).

44/12 = Ratio of molecular weights, CO₂ to carbon.

- (F_g) = Annual volume of the gaseous fuel combusted (scf).
- (C_{gf}) = Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).
- MW = Molecular weight of the gaseous fuel (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
- 0.001 = Conversion factor from kg to metric tons.
- (Ore) = Annual mass of iron ore or iron ore pellets fed to the furnace (metric tons).
- (C_{Ore}) = Carbon content of the iron ore or iron ore pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).
- (C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Other) = Annual mass of other materials charged to the furnace (metric tons).
- (C_{Other}) = Average carbon content of the other materials charged to the furnace, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (Iron) = Annual mass of iron produced (metric tons).
- (C_{Iron}) = Carbon content of the iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (NM) = Annual mass of non-metallic materials produced by the furnace (metric tons).
- (C_{NM}) = Carbon content of the non-metallic materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- (R) = Annual mass of air pollution control residue collected (metric tons).
- (C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(2) Site-specific emission factor method. Conduct a performance test and measure CO₂ emissions from all exhaust stacks for the process and measure either the feed rate of materials into the process or the production rate during the test as described in paragraphs (b) (2) (i) through (b) (2) (iv) of this section.

(i) You must measure the process production rate or process feed rate, as applicable, during the performance test according to the procedures in §98.174(c) (5) and calculate the average rate for the test period in metric tons per hour.

(ii) You must calculate the hourly CO₂ emission rate using Equation Q-8 of this section and determine the average hourly CO₂ emission rate for the test.

$$CO_2 = 5.18 \times 10^{-7} * C_{CO_2} * Q * \left(\frac{100 - \%H_2O}{100} \right) \quad (\text{Eq. Q-8})$$

Where:

CO₂ = CO₂ mass emission rate, corrected for moisture (metric tons/hr).

5.18×10^{-7} = Conversion factor (metric tons/scf-% CO₂).

C_{CO₂} = Hourly CO₂ concentration, dry basis (% CO₂).

Q = Hourly stack gas volumetric flow rate (scfh).

%H₂O = Hourly moisture percentage in the stack gas.

(iii) You must calculate a site-specific emission factor for the process in metric tons of CO₂ per metric ton of feed or production, as applicable, by dividing the

average hourly CO₂ emission rate during the test by the average hourly feed or production rate during the test.

(iv) You must calculate CO₂ emissions for the process by multiplying the emission factor by the total amount of feed or production, as applicable, for the reporting period.

(c) You must determine emissions of CO₂ from the coke pushing process in mtCO₂e by multiplying the metric tons of coal charged to the coke ovens during the reporting period by 0.008.

(d) If GHG emissions from a taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, or direct reduction furnace are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated

requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§98.174 Monitoring and QA/QC requirements.

(a) If you operate and maintain a CEMS that measures CO₂ emissions consistent with subpart C of this part, you must meet the monitoring and QA/QC requirements of §98.34(c).

(b) If you determine CO₂ emissions using the carbon mass balance procedure in §98.173(b)(1), you must:

(1) Except as provided in paragraph (b)(4) of this section, determine the mass of each process input and output other than fuels using the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.), record the totals for each process input and output for each calendar month, and sum the monthly mass to determine the annual mass for each process input and output. Determine the mass rate of fuels using the procedures for combustion units in §98.34.

(2) Except as provided in paragraph (b)(4) of this section, determine the carbon content of each process input and output annually for use in the applicable equations in §98.173(b)(1) based on analyses provided by the supplier or

by the average carbon content determined by collecting and analyzing at least three samples each year using the standard methods specified in paragraphs (b) (2) (i) through (b) (2) (vi) of this section as applicable.

(i) ASTM C25-06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see §98.7) for limestone, dolomite, and slag.

(ii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7) for coal, coke, and other carbonaceous materials.

(iii) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry (incorporated by reference, see §98.7) for iron ore, taconite pellets, and other iron-bearing materials.

(iv) ASTM E1019-08, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques (incorporated by reference, see §98.7) for iron and ferrous scrap.

(v) ASM CS-104 UNS No. G10460 - Alloy Digest April 1985 (Carbon Steel of Medium Carbon Content) (incorporated by reference, see §98.7); ISO/TR 15349-1:1998, Unalloyed steel—Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998-10-15) First Edition (incorporated by reference, see §98.7); or ISO/TR 15349-3:1998, Unalloyed steel—Determination of low carbon content Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998-10-15) First Edition (incorporated by reference, see §98.7) as applicable for steel.

(vi) For each process input that is a fuel, determine the carbon content and molecular weight (if applicable) using the applicable methods listed in §98.34.

(3) For solid ferrous materials charged to basic oxygen process furnaces or EAFs that differ in carbon content, you may determine a weighted average carbon content based on the carbon content of each type of ferrous material and the average weight percent of each type that is used. Examples of these different ferrous materials include carbon steel, low carbon steel, stainless steel, high alloy steel, pig iron, iron scrap, and direct reduced iron.

(4) If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(5) Except as provided in paragraph (b)(4) of this section, you must determine the annual carbon content and monthly mass rate of any input or output that contains carbon that is not listed in the equations in §98.173(b)(1) using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(c) If you determine CO₂ emissions using the site-specific emission factor procedure in §98.173(b)(2), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) For the furnace exhaust from basic oxygen furnaces, EAFs, argon-oxygen decarburization vessels, and direct reduction furnaces, sample the furnace exhaust for at least three complete production cycles that start when the furnace is being charged and end after steel or iron and slag have been tapped. For EAFs that produce both carbon steel and stainless or specialty (low carbon) steel,

develop an emission factor for the production of both types of steel.

(3) For taconite indurating furnaces, non-recovery coke batteries, and sinter processes, sample for at least 3 hours.

(4) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A-2 to measure the CO₂ concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1 or Method 26 at 40 CFR part 60, appendix A-2 to determine the stack gas volumetric flow rate, and Method 4 at 40 CFR part 60, at appendix A-3 to determine the moisture content of the stack gas.

(5) Determine the mass rate of process feed or process production (as applicable) during the test using the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, combination of bulk density and volume measurements, etc.)

(6) If your process operates under different conditions as part of normal operations in such a manner that CO₂ emissions change by more than 20 percent (e.g., routine changes in the carbon content of the sinter feed or change in grade of product), you must perform emission testing and develop separate emission factors for these

different operating conditions and determine emissions based on the number of hours the process operates and the production or feed rate (as applicable) at each specific different condition.

(7) If your EAF and argon-oxygen decarburization vessel exhaust to a common emission control device and stack, you must sample each process in the ducts before the emissions are combined, sample each process when only one process is operating, or sample the combined emissions when both processes are operating and base the site-specific emission factor on the steel production rate of the EAF.

(8) The results of a performance test must include the analysis of samples, determination of emissions, and raw data. The performance test report must contain all information and data used to derive the emission factor.

(d) For a coke pushing process, determine the metric tons of coal charged to the coke ovens and record the totals for each pushing process for each calendar month. Coal charged to coke ovens can be measured using weigh belts or a combination of measuring volume and bulk density.

§98.175 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.173 is required.

Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content of inputs and outputs for facilities that estimate emissions using the carbon mass balance procedure in §98.173(b)(1) or for facilities that estimate emissions using the site-specific emission factor procedure in §98.173(b)(2); 100 percent data availability is required. You must repeat the test for average carbon contents of inputs and outputs according to the procedures in §98.174(b)(2). Similarly, you must repeat the test to determine the site-specific emission factor if data on the CO₂ emission rate, process production rate or process feed rate are missing.

(b) For missing records of the monthly mass or volume of carbon-containing inputs and outputs using the carbon mass balance procedure in §98.173(b)(1), the substitute data value must be based on the best available estimate of the mass of the input or output material from all available process data or data used for accounting purposes.

§98.176 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information required in paragraphs (a) through (f) of this section for each coke pushing operation; taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace:

(a) Unit identification number and annual CO₂ emissions (in metric tons).

(b) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel.

(c) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.37 for the Tier 4 Calculation Methodology.

(d) If a CEMS is not used to measure CO₂ emissions, then you must report for each process whether the emissions were determined using the carbon mass balance method in §98.173(b)(1) or the site-specific emission factor method in §98.173(b)(2).

(e) If you use the carbon mass balance method in §98.173(b)(1) to determine CO₂ emissions, you must report the following information for each process:

(1) The carbon content of each process input and output used to determine CO₂ emissions.

(2) Whether the carbon content was determined from information from the supplier or by laboratory analysis, and if by laboratory analysis, the method used.

(3) The annual volume of gaseous fuel (in standard cubic feet), the annual volume of liquid fuel (in gallons), and the annual mass (in metric tons) of all other process inputs and outputs used to determine CO₂ emissions.

(4) The molecular weight of gaseous fuels.

(5) If you used the missing data procedures in §98.175(b), you must report how the monthly mass for each process input or output with missing data was determined and the number of months the missing data procedures were used.

(f) If you used the site-specific emission factor method in §98.173(b)(2) to determine CO₂ emissions, you must report the following information for each process:

(1) The measured average hourly CO₂ emission rate during the test (in metric tons per hour).

(2) The average hourly feed or production rate (as applicable) during the test (in metric tons per hour).

(3) The site-specific emission factor (in metric tons of CO₂ per metric ton of feed or production, as applicable).

(4) The annual feed or production rate (as applicable) used to estimate annual CO₂ emissions (in metric tons).

§98.177 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (e) of this section, as applicable. Facilities that use CEMS to measure emissions must also retain records of the verification data required for the Tier 4 Calculation Methodology in §98.36(e).

(a) Records of all analyses and calculations conducted, including all information reported as required under §98.176.

(b) When the carbon mass balance method is used to estimate emissions for a process, the monthly mass of each process input and output that are used to determine the annual mass.

(c) Production capacity (in metric tons per year) for the production of taconite pellets, coke, sinter, iron, and raw steel.

(d) Annual operating hours for taconite furnaces, coke oven batteries, sinter production, blast furnaces, direct reduced iron furnaces, and electric arc furnaces.

(e) Facilities must keep records that include a detailed explanation of how company records or measurements are used to determine all sources of carbon input and output and the metric tons of coal charged to the coke ovens (e.g., weigh belts, a combination of measuring volume and bulk density). You also must document the procedures used to ensure the accuracy of the measurements of fuel usage including, but not limited to, calibration of weighing equipment, fuel flow meters, coal usage including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.178 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart R—Lead Production

§98.180 Definition of the source category.

The lead production source category consists of primary lead smelters and secondary lead smelters. A primary lead smelter is a facility engaged in the production of lead metal from lead sulfide ore concentrates through the use of pyrometallurgical techniques. A

secondary lead smelter is a facility at which lead-bearing scrap materials (including but not limited to, lead-acid batteries) are recycled by smelting into elemental lead or lead alloys.

§98.181 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a lead production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.182 GHGs to report.

You must report:

(a) Process CO₂ emissions from each smelting furnace used for lead production.

(b) CO₂ combustion emissions from each smelting furnace used for lead production.

(c) CH₄ and N₂O combustion emissions from each smelting furnace used for lead production. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than smelting furnaces used for lead production. You must report these emissions under subpart

C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.183 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each smelting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each smelting furnace that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each smelting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO₂ emissions from the smelting furnace by using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in

subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report process and combustion CO₂ emissions separately using the procedures specified in paragraphs (b) (2) (i) through (b) (2) (iii) of this section.

(i) For each smelting furnace, determine the annual mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into the smelting furnace and estimate annual process CO₂ emissions using Equation R-1 of this section. Carbon-containing materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R-1 of this section.

$$E_{\text{CO}_2} = \frac{44}{12} \times \frac{2000}{2205} \times [(Ore \times C_{Ore}) + (Scrap \times C_{Scrap}) + (Flux \times C_{Flux}) + (Carbon \times C_{Carbon}) + (Other \times C_{Other})] \text{ (Eq. R-1)}$$

Where:

E_{CO_2}	=	Annual process CO ₂ emissions from an individual smelting furnace (metric tons).
44/12	=	Ratio of molecular weights, CO ₂ to carbon.
2000/2205	=	Conversion factor to convert tons to metric tons.
Ore	=	Annual mass of lead ore charged to the smelting furnace (tons).
C_{Ore}	=	Carbon content of the lead ore, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
Scrap	=	Annual mass of lead scrap charged to the smelting furnace (tons).

C_{Scrap}	=	Carbon content of the lead scrap, from the carbon analysis (percent by weight, expressed as a decimal fraction).
Flux	=	Annual mass of flux materials (e.g., limestone, dolomite) charged to the smelting furnace (tons).
C_{Flux}	=	Carbon content of the flux materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).
Carbon	=	Annual mass of carbonaceous materials (e.g., coal, coke) charged to the smelting furnace (tons).
C_{Carbon}	=	Carbon content of the carbonaceous materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).
Other	=	Annual mass of any other material containing carbon, other than fuel, fed, charged, or otherwise introduced into the smelting furnace (tons).
C_{Other}	=	Carbon content of the other material from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(ii) Determine the combined annual process CO₂

emissions from the smelting furnaces at your facility using Equation R-2 of this section.

$$\text{CO}_2 = \sum_1^k E_{\text{CO}_2_k} \quad (\text{Eq. R-2})$$

Where:

CO ₂	=	Annual process CO ₂ emissions from smelting furnaces at facility used for lead production (metric tons).
$E_{\text{CO}_2_k}$	=	Annual process CO ₂ emissions from smelting furnace k calculated using Equation R-1 of this section (metric tons/year).
k	=	Total number of smelting furnaces at facility used for lead production.

(iii) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO₂ emissions from the smelting furnaces according to the applicable requirements in subpart C.

§98.184 Monitoring and QA/QC requirements.

If you determine process CO₂ emissions using the carbon mass balance procedure in §98.183(b)(2)(i) and (b)(2)(ii), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO₂ emissions using Equation R-1 of this subpart by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed or used in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section. If you document that a specific process input or output contributes less than one percent of the

total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material each year. The carbon content of the material must be analyzed at least annually using the methods (and their QA/QC procedures) specified in paragraphs (b) (2) (i) through (b) (2) (iii) of this section, as applicable.

(i) ASTM E1941-04, Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see §98.7) for analysis of metal ore and alloy product.

(ii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7), for analysis of carbonaceous reducing agents and carbon electrodes.

(iii) ASTM C25-06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see §98.7) for analysis of flux materials such as limestone or dolomite.

§98.185 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.183 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content for the smelting furnaces at your facility that estimate annual process CO₂ emissions using the carbon mass balance procedure in §98.183(b)(2)(i) and (ii), 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in §98.184(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

§98.186 Data Reporting Procedures.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO₂ emissions according to the requirements in §98.183(a) or (b)(1), then you must report under this subpart the relevant information required by §98.36 and the information specified in paragraphs (a)(1) through (a)(4) of this section.

- (1) Identification number of each smelting furnace.
- (2) Annual lead product production capacity (tons).
- (3) Annual production for each lead product (tons).
- (4) Total number of smelting furnaces at facility used for lead production.

(b) If a CEMS is not used to measure CO₂ emissions, and you measure CO₂ emissions according to the requirements in §98.183(b)(2)(i) and (b)(2)(ii), then you must report the information specified in paragraphs (b)(1) through (b)(9) of this section.

- (1) Identification number of each smelting furnace.
- (2) Annual process CO₂ emissions (in metric tons) from each smelting furnace as determined by Equation R-1 of this subpart.
- (3) Annual lead product production capacity for the facility and each smelting furnace(tons).
- (4) Annual production for each lead product (tons).

(5) Total number of smelting furnaces at facility used for production of lead products reported in paragraph (b) (4) of this section.

(6) Annual material quantity for each material used for the calculation of annual process CO₂ emissions using Equation R-1 of this subpart for each smelting furnace (tons).

(7) Annual average of the carbon content determinations for each material used for the calculation of annual process CO₂ emissions using Equation R-1 of this subpart for each smelting furnace.

(8) List the method used for the determination of carbon content for each material reported in paragraph (b) (7) of this section (e.g., supplier provided information, analyses of representative samples you collected).

(9) If you use the missing data procedures in §98.185(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

§98.187 Records that must be retained.

In addition to the records required by §98.3(g), each annual report must contain the information specified in

paragraphs (a) through (c) of this section, as applicable to the smelting furnaces at your facility.

(a) If a CEMS is used to measure combined process and combustion CO₂ emissions according to the requirements in §98.183(a) or (b)(1), then you must retain the records required for the Tier 4 Calculation Methodology in §98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(b) If the carbon mass balance procedure is used to determine process CO₂ emissions according to the requirements in §98.183(b)(2)(i) and (b)(2)(ii), then you must retain under this subpart the records specified in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO₂ emissions using Equation R-1 of this subpart (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO₂ emissions using Equation R-1 of this subpart.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each smelting furnace, , including documentation of any materials excluded from Equation R-1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an smelting furnace including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.188 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart S—Lime Manufacturing§98.190 Definition of the source category.

(a) Lime manufacturing plants (LMPs) engage in the manufacture of a lime product (e.g., calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other products) by calcination of limestone, dolomite, shells or other calcareous substances as defined in 40 CFR 63.7081(a)(1).

(b) This source category includes all LMPs unless the LMP is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source category consists of marketed and non-marketed lime manufacturing facilities.

(c) Lime kilns at pulp and paper manufacturing facilities must report emissions under subpart AA of this part (Pulp and Paper Manufacturing).

§98.191 Reporting threshold.

You must report GHG emissions under this subpart if your facility is a lime manufacturing plant as defined in

§98.190 and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.192 GHGs to report.

You must report:

(a) CO₂ process emissions from lime kilns.

(b) CO₂ emissions from fuel combustion at lime kilns.

(c) N₂O and CH₄ emissions from fuel combustion at each lime kiln. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(d) CO₂, N₂O, and CH₄ emissions from each stationary fuel combustion unit other than lime kilns. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(e) CO₂ collected and transferred off site under 40 CFR part 98, following the requirements of subpart PP of this part (Suppliers of Carbon Dioxide (CO₂)).

§98.193 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from all lime kilns combined using the procedure in paragraphs (a) and (b) of this section.

(a) If all lime kilns meet the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and

combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) If CEMS are not required to be used to determine CO₂ emissions from all lime kilns under paragraph (a) of this section, then you must calculate and report the process and combustion CO₂ emissions from the lime kilns by using the procedures in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions from all lime kilns according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report process and combustion CO₂ emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(v) of this section.

(i) You must calculate a monthly emission factor for each type of lime produced using Equation S-1 of this

section. Calcium oxide and magnesium oxide content must be analyzed monthly for each lime type:

$$EF_{LIME,i,n} = [(SR_{CaO} * CaO_{i,n}) + (SR_{MgO} * MgO_{i,n})] * \frac{2000}{2205} \quad (\text{Eq. S-1})$$

Where:

- $EF_{LIME,i,n}$ = Emission factor for lime type i , for month n (metric tons CO_2 /ton lime).
- SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate [see Table S-1 of this subpart] (metric tons CO_2 /metric tons CaO).
- SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S-1 of this subpart) (metric tons CO_2 /metric tons MgO).
- $CaO_{i,n}$ = Calcium oxide content for lime type i , for month n , determined according to §98.194(c) (metric tons CaO /metric ton lime).
- $MgO_{i,n}$ = Magnesium oxide content for lime type i , for month n , determined according to §98.194(c) (metric tons MgO /metric ton lime).
- 2000/2205 = Conversion factor for metric tons to tons.

(ii) You must calculate a monthly emission factor for each type of byproduct/waste sold (including lime kiln dust) using Equation S-2 of this section:

$$EF_{LKD,i,n} = [(SR_{CaO} * CaO_{LKD,i,n}) + (SR_{MgO} * MgO_{LKD,i,n})] * \frac{2000}{2205} \quad (\text{Eq. S-2})$$

Where:

- $EF_{LKD,i,n}$ = Emission factor for sold lime byproduct/waste type i , for month n (metric tons CO_2 /ton lime byproduct).
- SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate (see Table S-1 of this subpart) (metric tons CO_2 /metric tons CaO).

- SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S-1 of this subpart) (metric tons CO_2 /metric tons MgO).
 $CaO_{LKD, i, n}$ = Calcium oxide content for sold lime byproduct/waste type i , for month n (metric tons CaO/metric ton lime).
 $MgO_{LKD, i, n}$ = Magnesium oxide content for sold lime byproduct/waste type i , for month n (metric tons MgO/metric ton lime).
 2000/2205 = Conversion factor for metric tons to tons.

(iii) You must calculate the annual CO_2 emissions from each type of byproduct/waste that is not sold (including lime kiln dust and scrubber sludge) using Equation S-3 of this section:

$$E_{waste, i} = [(SR_{CaO} * CaO_{waste, i}) + (SR_{MgO} * MgO_{waste, i})] * M_{waste, i} * \frac{2000}{2205} \quad (\text{Eq. S-3})$$

Where:

- $E_{waste, i}$ = Annual CO_2 emissions for unsold lime byproduct/waste type i (metric tons CO_2).
 SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate (see Table S-1 of this subpart) (metric tons CO_2 /metric tons CaO).
 SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S-1 of this subpart) (metric tons CO_2 /metric tons MgO).
 $CaO_{waste, i}$ = Calcium oxide content for unsold lime byproduct/waste type i (metric tons CaO/metric ton lime).
 $MgO_{waste, i}$ = Magnesium oxide content for unsold lime byproduct/waste type i (metric tons MgO/metric ton lime).
 $M_{waste, i}$ = Annual weight or mass of unsold byproducts/wastes for lime type i (tons).
 2000/2205 = Conversion factor for metric tons to tons.

(iv) You must calculate annual CO₂ process emissions for all kilns using Equation S-4 of this section:

$$E_{CO_2} = \sum_{i=1}^t \sum_{n=1}^{12} (EF_{LIME,i,n} * M_{LIME,i,n}) + \sum_{i=1}^b \sum_{n=1}^{12} EF_{LKD,i,n} * M_{LKD,i,n} + \sum_{i=1}^z E_{waste,i} \quad (\text{Eq. S-4})$$

Where:

- E_{CO_2} = Annual CO₂ process emissions from lime production from all kilns (metric tons/year).
- $EF_{LIME,i,n}$ = Emission factor for lime type i, in calendar month n (metric tons CO₂/ton lime) from Equation S-1 of this section.
- $M_{LIME,i,n}$ = Weight or mass of lime type i in calendar month n (tons).
- $EF_{LKD,i,n}$ = Emission factor of byproducts/wastes sold for lime type i in calendar month n, (metric tons CO₂/ton byproduct/waste) from Equation S-2 of this section.
- $M_{LKD,i,n}$ = Monthly weight or mass of byproducts/waste sold (such as lime kiln dust, LKD) for lime type i in calendar month n (tons).
- $E_{waste,i}$ = Annual CO₂ emissions for unsold lime byproduct/waste type i (metric tons CO₂) from Equation S-3 of this section.
- t = Number of lime types
- b = Number of byproducts/wastes sold
- z = Number of byproducts/wastes not sold

(v) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO₂ emissions from each lime kiln according to the applicable requirements in subpart C.

§98.194 Monitoring and QA/QC requirements.

(a) You must determine the total quantity of each product type of lime and each calcined byproduct/waste

(such as lime kiln dust) that is sold. The quantities of each should be directly measured monthly with the same plant instruments used for accounting purposes, including but not limited to, calibrated weigh feeders, rail or truck scales, and barge measurements. The direct measurements of each lime product shall be reconciled annually with the difference in the beginning of and end of year inventories for these products, when measurements represent lime sold.

(b) You must determine the annual quantity of each calcined byproduct/waste generated that is not sold by either direct measurement using the same instruments identified in paragraph (a) of this section or by using a calcined byproduct/waste generation rate.

(c) You must determine the chemical composition (percent total CaO and percent total MgO) of each type of lime and each type of calcined byproduct/waste sold according to paragraph (c) (1) or (c) (2) of this section. You must determine the chemical composition of each type of lime on a monthly basis. You must determine the chemical composition for each type of calcined byproduct/waste that is not sold on an annual basis.

(1) ASTM C25-06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference-see §98.7).

(2) The National Lime Association's CO₂ Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision-National Lime Association (incorporated by reference see §98.7).

(d) You must use the analysis of calcium oxide and magnesium oxide content of each lime product collected during the same month as the production data in monthly calculations.

(e) You must follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO₂ Emissions Calculation Protocol for the Lime Industry-English Units Version, February 5, 2008 Revision-National Lime Association (incorporated by reference see §98.7).

§98.195 Procedures for estimating missing data.

For the procedure in §98.193(b)(2), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the quantity of lime produced (by lime type), and quantity of byproduct/waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.

(b) For missing values related to the CaO and MgO content, you must conduct a new composition test according to the standard methods in §98.194 (c) (1) or (c) (2).

§98.196 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required by §98.36 and the information listed in paragraphs (a) (1) through (a) (8) of this section.

(1) Method used to determine the quantity of lime sold.

(2) Method used to determine the quantity of lime byproduct/waste sold.

(3) Beginning and end of year inventories for each lime product.

(4) Beginning and end of year inventories for lime byproducts/wastes.

(5) Annual amount of lime byproduct/waste sold, by type (tons).

(6) Annual amount of lime product sold, by type (tons).

(7) Annual amount of lime byproduct/waste not sold, by type (tons).

(8) Annual amount of lime product not sold, by type (tons).

(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in paragraphs (b)(1) through (b)(17) of this section.

(1) Annual CO₂ process emissions from all kilns combined (metric tons).

(2) Monthly emission factors for each lime type.

(3) Monthly emission factors for each sold byproduct/waste by lime type.

(4) Standard method used (ASTM or NLA testing method) to determine chemical compositions of each lime type and lime byproduct/waste type.

(5) Monthly results of chemical composition analysis of each lime product and byproduct/waste sold.

(6) Annual results of chemical composition analysis of each type of lime byproduct/waste not sold.

- (7) Method used to determine the quantity of lime sold.
- (8) Monthly amount of lime product sold, by type (tons).
- (9) Method used to determine the quantity of lime byproduct/waste sold.
- (10) Monthly amount of lime byproduct/waste sold, by type (tons).
- (11) Annual amount of lime byproduct/waste not sold (tons).
- (12) Monthly mass of each lime type produced (tons).
- (13) Beginning and end of year inventories for each lime product.
- (14) Beginning and end of year inventories for lime byproducts/wastes.
- (15) Annual lime production capacity (tons) per facility.
- (16) Number of times in the reporting year that missing data procedures were followed to measure lime production (months) or the chemical composition of lime products sold (months).
- (17) Indicate whether CO₂ was used on-site (i.e. for use in a purification process). If CO₂ was used on-site,

provide the information in paragraphs (b) (17) (i) and (b) (17) (ii) of this section.

(i) The annual amount of CO₂ captured for use in the on-site process.

(ii) The method used to determine the amount of CO₂ captured.

§98.197 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section.

(a) Annual operating hours in calendar year.

(b) Records of all analyses (e.g. chemical composition of lime products, by type) and calculations conducted.

§98.198 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table S-1 of Subpart S—Basic Parameters for the Calculation of Emission Factors for Lime Production

Variable	Stoichiometric ratio
SR _{CaO}	0.7848
SR _{MgO}	1.0918

Subpart T [RESERVED]

Subpart U—Miscellaneous Uses of Carbonate

§98.210 Definition of the source category.

(a) This source category includes any equipment that uses carbonates listed in Table U-1 in manufacturing processes that emit carbon dioxide. Table U-1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO₂ if they consume at least 2,000 tons per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

(b) This source category does not include equipment that uses carbonates or carbonate containing minerals that are consumed in the production of cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc.

(c) This source category does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under 40 CFR 98, subpart C (Stationary Fuel Combustion Sources).

§98.211 Reporting threshold.

You must report GHG emissions from miscellaneous uses of carbonate if your facility uses carbonates as defined in

§98.210 of this subpart and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.212 GHGs to report.

You must report CO₂ process emissions from all miscellaneous carbonate use at your facility as specified in this subpart.

§98.213 Calculating GHG emissions.

You must determine CO₂ process emissions from carbonate use in accordance with the procedures specified in either paragraphs (a) or (b) of this section.

(a) Calculate the process emissions of CO₂ using calcination fractions with Equation U-1 of this section.

$$E_{\text{CO}_2} = \sum_{i=1}^n M_i * EF_i * F_i * \frac{2000}{2205} \quad (\text{Eq. U-1})$$

Where:

- E_{CO_2} = Annual CO₂ mass emissions from consumption of carbonates (metric tons).
- M_i = Annual mass of carbonate type i consumed (tons).
- EF_i = Emission factor for the carbonate type i , as specified in Table U-1 to this subpart, metric tons CO₂/metric ton carbonate consumed.
- F_i = Fraction calcination achieved for each particular carbonate type i (decimal fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.
- n = Number of carbonate types.
- 2000/2205 = Conversion factor to convert tons to metric tons.

(b) Calculate the process emissions of CO₂ using actual mass of output carbonates with Equation U-2 of this section.

$$E_{\text{CO}_2} = \left[\sum_{k=1}^m (M_k * EF_k) - \sum_{j=1}^n (M_j * EF_j) \right] * \frac{2000}{2205} \quad (\text{Eq. U-2})$$

Where:

E_{CO_2}	=	Annual CO ₂ mass emissions from consumption of carbonates (metric tons).
M_k	=	Annual mass of input carbonate type k (tons).
EF_k	=	Emission factor for the carbonate type k, as specified in Table U-1 of this subpart (metric tons CO ₂ /metric ton carbonate input).
M_j	=	Annual mass of output carbonate type j (tons).
EF_j	=	Emission factor for the output carbonate type j, as specified in Table U-1 of this subpart (metric tons CO ₂ /metric ton carbonate input).
m	=	Number of input carbonate types.
n	=	Number of output carbonate types.

§98.214 Monitoring and QA/QC requirements.

(a) The annual mass of carbonate consumed (for Equation U-1 of this subpart) or carbonate inputs (for Equation U-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.

(b) The annual mass of carbonate outputs (for Equation U-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

(c) If you follow the procedures of §98.213(a), as an alternative to assuming a calcination fraction of 1.0, you can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).

§98.215 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (b) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate

input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes.

§98.216 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (g) of this section at the facility level, as applicable.

(a) Annual CO₂ emissions from miscellaneous carbonate use (metric tons).

(b) Annual mass of each carbonate type consumed (tons).

(c) Measurement method used to determine the mass of carbonate.

(d) Method used to calculate emissions.

(e) If you followed the calculation method of §98.213(b)(1)(i), you must report the information in paragraphs (e)(1) through (e)(3) of this section.

(1) Annual carbonate consumption by carbonate type (tons).

(2) Annual calcination fractions used in calculations.

(3) If you determined the calcination fraction, indicate which standard method was used.

(f) If you followed the calculation method of §98.213(b)(1)(ii), you must report the information in paragraphs (f)(1) and (f)(2) of this section.

(1) Annual carbonate input by carbonate type (tons).

(2) Annual carbonate output by carbonate type (tons).

(g) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

§98.217 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section:

(a) Monthly carbonate consumption (by carbonate type in tons).

(b) You must document the procedures used to ensure the accuracy of the monthly measurements of carbonate consumption, carbonate input or carbonate output including, but not limited to, calibration of weighing equipment and other measurement devices.

(c) Records of all analyses conducted to meet the requirements of this rule.

(d) Records of all calculations conducted.

§98.218 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table U-1 of Subpart U—CO₂ Emission Factors for Common Carbonates

Mineral Name - Carbonate	CO₂ Emission Factor (tons CO₂/ton carbonate)
Limestone - CaCO ₃	0.43971
Magnesite - MgCO ₃	0.52197
Dolomite - CaMg (CO ₃) ₂	0.47732
Siderite - FeCO ₃	0.37987
Ankerite - Ca (Fe, Mg, Mn) (CO ₃) ₂	0.47572
Rhodochrosite - MnCO ₃	0.38286
Sodium Carbonate/Soda Ash - Na ₂ CO ₃	0.41492

Subpart V—Nitric Acid Production

§98.220 Definition of Source Category.

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 percent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.

§98.221 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a nitric acid train and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.222 GHGs to report.

(a) You must report N₂O process emissions from each nitric acid production train as required by this subpart.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions

of CO₂, CH₄, and N₂O from each stationary combustion unit by following the requirements of subpart C.

§98.223 Calculating GHG emissions.

(a) You must determine annual N₂O process emissions from each nitric acid train according to paragraphs (a) (1) or (a) (2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Administrator approval for an alternative method of determining N₂O emissions according to paragraphs (a) (2) (i) and (a) (2) (ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N₂O emissions factor for the current reporting period using the procedures specified in paragraph (a) (1) of this section.

(b) You must conduct an annual performance test according to paragraphs (b) (1) through (b) (3) of this section.

(1) You must measure N₂O emissions from the absorber tail gas vent for each nitric acid train using the methods specified in §98.224(b) through (d).

(2) You must conduct the performance test under normal process operating conditions and without using N₂O abatement technology (if applicable).

(3) You must measure the production rate during the performance test and calculate the production rate for the test period in metric tons (100 percent acid basis) per hour.

(c) You must determine an N₂O emissions factor to use in Equation V-3 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) You may request Administrator approval for an alternative method of determining N₂O concentration according to the procedures in paragraphs (a)(2)(i) and (a)(2)(ii) of this section. Alternative methods include the use of N₂O CEMs.

(2) Using the results of the performance test in paragraph (b) of this section, you must calculate an average site-specific emission factor for each nitric acid train "t" according to Equation V-1 of this section:

$$EF_{N_2O_t} = \frac{\sum_1^n \frac{C_{N_2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \quad (\text{Eq. V-1})$$

Where:

- $EF_{N_2O_t}$ = Average site-specific N_2O emissions factor for nitric acid train "t" (lb N_2O generated/ton nitric acid produced, 100 percent acid basis).
- C_{N_2O} = N_2O concentration for each test run during the performance test (ppm N_2O).
- 1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).
- Q = Volumetric flow rate of effluent gas for each test run during the performance test (dscf/hr).
- P = Production rate for each test run during the performance test (tons nitric acid produced per hour, 100 percent acid basis).
- n = Number of test runs.

(d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology according to paragraphs (d) (1), (d) (2), or (d) (3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N₂O abatement technology.

(e) If applicable, you must determine the abatement factor for each N₂O abatement technology. The abatement factor is calculated for each nitric acid train according to Equation V-2 of this section.

$$AF_{N_t} = \frac{P_{at\ Abate}}{P_{at}} \quad (\text{Eq. V-2})$$

Where:

AF_{N_t} = Abatement factor of N₂O abatement technology at nitric acid train "t" (fraction of annual production that abatement technology is operating).

$P_{a\ t}$ = Total annual nitric acid production from nitric acid train "t" (ton acid produced, 100 percent acid basis).

$P_{a\ t\ Abate}$ = Annual nitric acid production from nitric acid train "t" during which N₂O abatement was used (ton acid produced, 100 percent acid basis).

(f) You must determine the annual amount of nitric acid produced and the annual amount of nitric acid produced while each N₂O abatement technology is operating from each nitric acid train (100 percent basis).

(g) You must calculate N₂O emissions for each nitric acid train by multiplying the emissions factor (determined in Equation V-1 of this section) by the annual nitric acid

production and accounting for N₂O abatement, according to Equation V-3 of this section:

$$E_{N_2O_t} = \sum_{N=1}^z \frac{EF_{N2O_t} * P_{at} * (1 - (DF_{N_t} * AF_{N_t}))}{2204.63} \quad (\text{Eq. V-3})$$

Where:

- $E_{N_2O_t}$ = N₂O mass emissions per year for nitric acid train "t" (metric tons).
- $EF_{N_2O_t}$ = Average site-specific N₂O emissions factor for nitric acid train "t" (lb N₂O generated/ton acid produced, 100 percent acid basis).
- $P_{a t}$ = Annual nitric acid production from the train "t" (ton acid produced, 100 percent acid basis).
- $DF_{N t}$ = Destruction efficiency of N₂O abatement technology N that is used on nitric acid train "t" (percent of N₂O removed from air stream).
- $AF_{N t}$ = Abatement factor of N₂O abatement technology for nitric acid train "t" (fraction of annual production that abatement technology is operating).
- 2204.63 = Conversion factor (lb/metric ton).
- z = Number of different N₂O abatement technologies.

(h) You must determine the annual nitric acid production emissions combined from all nitric acid trains at your facility using Equation V-4 of this section:

$$N_2O = \sum_{t=1}^m E_{N_2O_t} \quad (\text{Eq. V-4})$$

Where:

- N₂O = Annual process N₂O emissions from nitric acid production facility (metric tons)
- $E_{N_2O_t}$ = N₂O mass emissions per year for nitric acid train "t" (metric tons).
- m = Number of nitric acid trains.

§98.224 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new site-specific emissions factor according to a test plan as specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Conduct the performance test annually.

(2) Conduct the performance test when your nitric acid production process is changed, specifically when abatement equipment is installed.

(3) If you requested Administrator approval for an alternative method of determining N₂O concentration under §98.223(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N₂O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.

(2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference in §98.7).

(3) An equivalent method, with Administrator approval.

(c) You must determine the production rate(s) (100 percent basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (c)(2) of this section.

(1) Direct measurement of production and concentration (such as using flow meters, weigh scales, for production and concentration measurements).

(2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).

(d) You must conduct all performance tests in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A-1 through A-4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination

report that must include the items in paragraphs (d) (1) through (d) (3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined.

(e) You must determine the monthly nitric acid production and the monthly nitric acid production during which N₂O abatement technology is operating from each nitric acid train according to the methods in paragraphs (c) (1) or (c) (2) of this section.

(f) You must determine the annual nitric acid production and the annual nitric acid production during which N₂O abatement technology is operating for each train by summing the respective monthly nitric acid production quantities.

§98.225 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing

parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N₂O concentration, you must conduct a new performance test according to the procedures in §98.224 (a) through (d).

§98.226 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (o) of this section for each nitric acid production train.

(a) Train identification number.

(b) Annual process N₂O emissions from each nitric acid train (metric tons).

(c) Annual nitric acid production from each nitric acid train (tons, 100 percent acid basis).

(d) Annual nitric acid production from each nitric acid train during which N₂O abatement technology is operating (ton acid produced, 100 percent acid basis)

- (e) Annual nitric acid production from the nitric acid facility (tons, 100 percent acid basis).
- (f) Number of nitric acid trains.
- (g) Number of abatement technologies (if applicable).
- (h) Abatement technologies used (if applicable).
- (i) Abatement technology destruction efficiency for each abatement technology (percent destruction).
- (j) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).
- (k) Type of nitric acid process used for each nitric acid train (low, medium, high, or dual pressure).
- (l) Number of times in the reporting year that missing data procedures were followed to measure nitric acid production (months).
- (m) If you conducted a performance test and calculated a site-specific emissions factor according to §98.223(a)(1), each annual report must also contain the information specified in paragraphs (m)(1) through (m)(7) of this section for each nitric acid production facility.
 - (1) Emission factor calculated for each nitric acid train (lb N₂O/ ton nitric acid, 100 percent acid basis).
 - (2) Test method used for performance test.

(3) Production rate per test run during performance test (tons nitric acid produced/hr, 100 percent acid basis).

(4) N₂O concentration per test run during performance test (ppm N₂O).

(5) Volumetric flow rate per test run during performance test (dscf/hr).

(6) Number of test runs during performance test.

(7) Number of times in the reporting year that a performance test had to be repeated (number).

(n) If you requested Administrator approval for an alternative method of determining N₂O concentration under §98.223(a)(2), each annual report must also contain the information specified in paragraphs (n)(1) through (n)(4) of this section for each nitric acid production facility.

(1) Name of alternative method.

(2) Description of alternative method.

(3) Request date.

(4) Approval date.

(o) Total pounds of synthetic fertilizer produced through and total nitrogen contained in that fertilizer.

§98.227 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a)

through (g) of this section for each nitric acid production facility:

- (a) Records of significant changes to process.
- (b) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency (if applicable).
- (c) Performance test reports.
- (d) Number of operating hours in the calendar year for each nitric acid train (hours).
- (e) Annual nitric acid permitted production capacity (tons).
- (f) Measurements, records, and calculations used to determine reported parameters.
- (g) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.228 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart W [RESERVED]

Subpart X—Petrochemical Production§98.240 Definition of the source category.

(a) The petrochemical production source category consists of all processes that produce acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol, except as specified in paragraphs (b) through (f) of this section. The source category includes processes that produce the petrochemical as an intermediate in the onsite production of other chemicals as well as processes that produce the petrochemical as an end product for sale or shipment offsite.

(b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source category.

(c) A facility that makes methanol, hydrogen, and/or ammonia from synthesis gas is part of the petrochemical source category if the annual mass of methanol produced exceeds the individual annual mass production levels of both hydrogen recovered as product and ammonia. The facility is part of subpart P of this part (Hydrogen Production) if the annual mass of hydrogen recovered as product exceeds the individual annual mass production levels of both methanol and ammonia. The facility is part of subpart G of this part (Ammonia Manufacturing) if the

annual mass of ammonia produced exceeds the individual annual mass production levels of both hydrogen recovered as product and methanol.

(d) A direct chlorination process that is operated independently of an oxychlorination process to produce ethylene dichloride is not part of the petrochemical production source category.

(e) A process that produces bone black is not part of the petrochemical source category.

(f) A process that produces a petrochemical from bio-based feedstock is not part of the petrochemical production source category.

§98.241 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petrochemical process as specified in §98.240, and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.242 GHGs to report.

You must report the information in paragraphs (a) through (c) of this section:

(a) CO₂, CH₄, and N₂O process emissions from each petrochemical process unit. Process emissions include CO₂ generated by reaction in the process and by combustion of process off-gas in stationary combustion units and flares.

(1) If you comply with §98.243(b) or (d), report under this subpart the calculated CO₂, CH₄, and N₂O emissions for each stationary combustion source and flare that burns any amount of petrochemical process off-gas.

(2) If you comply with §98.243(c), report under this subpart the calculated CO₂ emissions for each petrochemical process unit.

(b) CO₂, CH₄, and N₂O combustion emissions from stationary combustion units and flares.

(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.

(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.

(c) CO₂ captured. You must report the mass of CO₂ captured under, subpart PP of this part (Suppliers of Carbon Dioxide (CO₂) by following the requirements of subpart PP.

§98.243 Calculating GHG emissions.

(a) If you route all process vent emissions and emissions from combustion of process off-gas to one or more stacks and use CEMS on each stack to measure CO₂ emissions (except flare stacks), then you must determine process-based GHG emissions in accordance with paragraph (b) of this section. Otherwise, determine process-based GHG emissions in accordance with the procedures specified in paragraph (c) or (d) of this section.

(b) Continuous emission monitoring system (CEMS). Route all process vent emissions and emissions from combustion of process off-gas to one or more stacks and determine CO₂ emissions from each stack (except flare stacks) according to the Tier 4 Calculation Methodology requirements in subpart C of this part. For each stack (except flare stacks) that includes emissions from combustion of petrochemical process off-gas, calculate CH₄ and N₂O emissions in accordance with subpart C of this part (use the Tier 3 methodology and emission factors for "Petroleum" in Table C-2 of subpart C of this part). For

each flare, calculate CO₂, CH₄, and N₂O emissions using the methodology specified in §98.253(b)(1) through (b)(3).

(c) Mass balance for each petrochemical process unit.

Calculate the emissions of CO₂ from each process unit, for each calendar month as described in paragraphs (c)(1) through (c)(5) of this section.

(1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter by following the procedures specified in §98.244(b)(2). Alternatively, for liquids, you may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid) following the procedures specified in §98.244(b)(3). Fuels used for combustion purposes are not considered to be feedstocks.

(2) For each solid feedstock and product, measure the mass used or produced each calendar month by following the procedures specified in §98.244(b)(1).

(3) 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). Alternatively, you may use the results of analyses

conducted by a fuel or feedstock supplier, provided the sampling and analysis is conducted at least once per month using any of the procedures specified in §98.244(b) (4). If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically.

(4) If you determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 percent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (c) (3) of this section, you may calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound during periods of normal operation. You must maintain records of any determination made in accordance with this paragraph (c) (4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. You must reevaluate determinations made under this paragraph (c) (4) after any process change that affects the feedstock or product composition. You must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the

average monthly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(5) Calculate the CO₂ mass emissions for each petrochemical process unit using Equations X-1 through X-4 of this section.

(i) Gaseous feedstocks and products. Use Equation X-1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12} \left[\sum_{i=1}^{j \text{ or } k} \left[(F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC} \right] \right] \quad (\text{Eq. X-1})$$

Where:

- C_g = Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kilograms/year, kg/yr).
- $(F_{gf})_{i,n}$ = Volume of gaseous feedstock i introduced in month "n" (standard cubic feet, scf).
- $(CC_{gf})_{i,n}$ = Average carbon content of the gaseous feedstock i for month "n" (kg C per kg of feedstock).
- $(MW_f)_i$ = Molecular weight of gaseous feedstock i (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
- $(P_{gp})_{i,n}$ = Volume of gaseous product i produced in month "n" (scf).
- $(CC_{gp})_{i,n}$ = Average carbon content of gaseous product i, including streams containing CO₂ recovered for sale or use in another process, for month "n" (kg C per kg of product).
- $(MW_p)_i$ = Molecular weight of gaseous product i (kg/kg-mole).
- j = Number of feedstocks.

k = Number of products.

(ii) Liquid feedstocks and products. Use Equation X-2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12} \left[\sum_{i=1}^{j \text{ or } k} [(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n}] \right] \quad (\text{Eq. X-2})$$

Where:

- C_l = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).
- $(F_{lf})_{i,n}$ = Volume or mass of liquid feedstock i introduced in month "n" (gallons or kg).
- $(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for month "n" (kg C per gallon or kg of feedstock).
- $(P_{lp})_{i,n}$ = Volume or mass of liquid product i produced in month "n" (gallons or kg).
- $(CC_{lp})_{i,n}$ = Average carbon content of liquid product i, including organic liquid wastes, for month "n" (kg C per gallon or kg of product).
- j = Number of feedstocks.
- k = Number of products.

(iii) Solid feedstocks and products. Use Equation X-3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12} \left\{ \sum_{i=1}^{j \text{ or } k} [(F_{sf})_{i,n} * (CC_{sf})_{i,n} - (P_{sp})_{i,n} * (CC_{sp})_{i,n}] \right\} \quad (\text{Eq. X-3})$$

Where:

- C_s = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).
- $(F_{sf})_{i,n}$ = Mass of solid feedstock i introduced in month "n" (kg).
- $(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock i for month "n" (kg C per kg of feedstock).
- $(P_{sp})_{i,n}$ = Mass of solid product i produced in month "n" (kg).
- $(CC_{sp})_{i,n}$ = Average carbon content of solid product i in month "n" (kg C per kg of product).
- j = Number of feedstocks.
- k = Number of products.

(iv) Annual emissions. Use the results from

Equations X-1 through X-3 of this section, as applicable, in Equation X-4 of this section to calculate annual CO₂ emissions.

$$CO_2 = 0.001 * \frac{44}{12} * (C_g + C_l + C_s) \quad (\text{Eq. X-4})$$

Where:

- CO₂ = Annual CO₂ mass emissions from process operations and process off-gas combustion (metric tons/year).
- 0.001 = Conversion factor from kg to metric tons.
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- 12 = Atomic weight of carbon (C) (kg/kg-mole).

(d) Optional combustion methodology for ethylene production processes. For any ethylene production process, calculate CO₂ emissions from combustion of fuel that contains ethylene process off-gas using the Tier 3 or Tier 4 methodology in subpart C of this part, and calculate CH₄

and N₂O emissions using the applicable procedures in §98.33(c) (use the emission factors for "Petroleum" in Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources)). You are not required to use the same Tier for each stationary combustion unit that burns ethylene process off-gas. For each flare, calculate CO₂, CH₄, and N₂O emissions using the methodology specified in §98.253(b) (1) through (b) (3).

§98.244 Monitoring and QA/QC requirements.

(a) If you use CEMS to determine emissions from process vents, you must comply with the procedures specified in §98.34(c).

(b) If you use the mass balance methodology in §98.243(c), use the procedures specified in paragraphs (b) (1) through (b) (4) of this section to determine feedstock and product flows and carbon contents.

(1) Operate and maintain belt scales or other weighing devices as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices NIST Handbook 44 (2009) (incorporated by reference, see §98.7) or follow procedures specified by the measurement device manufacturer. Calibrate the measurement device according to the procedures specified by the method, the procedures specified by the manufacturer,

or §98.3(i). Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(2) Operate and maintain all flow meters for gas and liquid feedstocks and products by following the procedures in §98.3(i) and using any of the flow meter methods specified in paragraphs (b)(2)(i) through (b)(2)(xv) of this section, as applicable, use a standard method published by a consensus-based standards organization (e.g., ASTM, API, etc.), or follow procedures specified by the flow meter manufacturer or §98.3(i). Recalibrate each flow meter either biennially or at the minimum frequency specified by the manufacturer.

(i) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(ii) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(iii) ASME MFC-5M-1985 (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, see §98.7).

(iv) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(v) ASME MFC-7M-1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(vi) ASME MFC-9M-1988 (Reaffirmed 2001) Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, see §98.7).

(vii) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, see §98.7).

(viii) ASME MFC-14M-2003 (Reaffirmed 2008), Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, see §98.7).

(ix) ASME MFC-16-2007 Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters (incorporated by reference, see §98.7).

(x) ASME MFC-18M-2001 (Reaffirmed 2006), Measurement of Fluid Flow Using Variable Area Meters (incorporated by reference, see §98.7).

(xi) ASME MFC-22-2007 Measurement of Liquid by Turbine Flowmeters (incorporated by reference, see §98.7).

(xii) AGA Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (2000) (incorporated by reference, see §98.7).

(xiii) AGA Transmission Measurement Committee Report No. 7: Measurement of Natural Gas by Turbine Meter (2006)/February (incorporated by reference, see §98.7).

(xiv) AGA Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003) (incorporated by reference, see §98.7).

(xv) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987-10-01) First Edition (incorporated by reference, see §98.7).

(3) Perform tank level measurements (if used to determine feedstock or product flows) according to any standard method published by a consensus-based standards organization (e.g., ASTM, API, etc.) or follow procedures specified by the measurement device manufacturer or §98.3(i). Calibrate the measurement devices prior to the effective date of the rule, and recalibrate either biennially or at the minimum frequency specified by the manufacturer or §98.3(i).

(4) Use any of the standard methods specified in paragraphs (b) (4) (i) through (b) (4) (x) of this section, as applicable, to determine the carbon content or composition of feedstocks and products and the average molecular weight of gaseous feedstocks and products. Calibrate instruments in accordance with the method and as specified in paragraphs (b) (4) (i) through (b) (4) (x), as applicable. For coal used as a feedstock, the samples for carbon content determinations shall be taken at a location that is representative of the coal feedstock used during the corresponding monthly period. For carbon black products, samples shall be taken of each grade or type of product produced during the monthly period. Samples of coal feedstock or carbon black product for carbon content determinations may be either grab samples collected and analyzed monthly or a composite of samples collected more frequently and analyzed monthly. Analyses conducted in accordance with methods specified in paragraphs (b) (4) (i) through (b) (4) (x) of this section may be performed by the owner or operator, by an independent laboratory, or by the supplier of a feedstock.

(i) ASTM D1945-03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

- (ii) ASTM D6060-96 (Reapproved 2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph (incorporated by reference, see §98.7).
- (iii) ASTM D2505-88 (Reapproved 2004) Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography (incorporated by reference, see §98.7).
- (iv) ASTM UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).
- (v) ASTM D3176-89 (Reapproved 2002) Standard Practice Method for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).
- (vi) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).
- (vii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).
- (viii) Methods 8031, 8021, or 8015 in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846, Third Edition, September 1986, as amended by Update I, November 15, 1992.

(ix) Method 18 at 40 CFR part 60, appendix A-6.

(x) Performance Specification 9 in 40 CFR part 60, appendix B for continuous online gas analyzers. The 7-day calibration error test period must be completed prior to the effective date of the rule.

§98.245 Procedures for estimating missing data.

For missing feedstock flow rates, product flow rates, and carbon contents, use the same procedures as for missing flow rates and carbon contents for fuels as specified in §98.35.

§98.246 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a), (b), or (c) of this section, as appropriate for each process unit.

(a) If you use the mass balance methodology in §98.243(c), you must report the information specified in paragraphs (a)(1) through (a)(10) of this section for each type of petrochemical produced, reported by process unit.

(1) The petrochemical process unit ID number or other appropriate descriptor.

(2) The type of petrochemical produced, names of other products, and names of carbon-containing feedstocks.

(3) Annual CO₂ emissions calculated using Equation X-4 of this subpart.

(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 for gaseous feedstocks and products used in Equation X-1 of this subpart. Indicate whether you used the alternative to sampling and analysis specified in §98.243(c)(4).

(5) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(6) Name of each method listed in §98.244 used to determine a measured parameter (or description of manufacturer's recommended method).

(7) The dates and summarized results (e.g., percent calibration error) of the calibrations of each measurement device.

(8) Identification of each combustion unit that burned both process off-gas and supplemental fuel.

(9) If you comply with the alternative to sampling and analysis specified in §98.243(c)(4), the amount of time during which off-specification product was produced, the

volume or mass of off-specification product produced, and if applicable, the date of any process change that reduced the composition to less than 99.5 percent.

(10) You may elect to report the flow and carbon content of wastewater, and you may elect to report the carbon content of hydrocarbons in fugitive emissions and in process vents that are not controlled with a combustion device. These values may be estimated based on engineering analyses. These values are not to be used in the mass balance calculation.

(b) If you use CEMS to measure CO₂ emissions in accordance with §98.243(b), then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the information listed in paragraphs (b)(1) through (b)(6) of this section.

(1) For CEMS used on stacks for stationary combustion units, report the relevant information required under §98.36 for the Tier 4 calculation methodology.

(2) For CEMS used on stacks that are not used for stationary combustion units, report the information required under §98.36(e)(2)(vi) and (vii). (3) The petrochemical process unit ID or other appropriate descriptor, and the type of petrochemical produced.

(4) The CO₂ emissions from each stack and the combined CO₂ emissions from all stacks (except flare stacks) that handle process vent emissions and emissions from stationary combustion units that burn process off-gas for the petrochemical process unit. If a stationary combustion source serves multiple petrochemical process units or units other than the petrochemical process unit, estimate based on engineering judgment the fraction of fuel energy and emissions attributable to each petrochemical process unit.

(5) The CH₄ and N₂O emissions from each stack and the combined CH₄ and N₂O emissions from all stationary combustion units that burn process off-gas from the petrochemical process unit, the cumulative annual heat input used in Equation C-10 in §98.33(c) of this subpart, and the annual flow of each fuel on which this heat input is based.

(6) ID or other appropriate descriptor of each stationary combustion unit that burns process off-gas.

(7) Information listed in §98.256(e) of subpart Y of this part for each flare that burns process off-gas.

(8) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(c) If you comply with the combustion methodology specified in §98.243(d), you must report under this subpart

the information listed in paragraphs (c) (1) through (c) (4) of this section.

(1) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), the relevant information listed in §98.36 for the selected Tier 3 or Tier 4 methodology. If a stationary combustion source serves multiple ethylene process units or units other than the ethylene process unit, estimate based on engineering judgment the fraction of fuel energy and emissions attributable to each ethylene process unit.

(2) Information listed in §98.256(e) for each flare that burns ethylene process off-gas.

(3) Name and annual quantity of each feedstock.

(4) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

§98.247 Records that must be retained.

In addition to the recordkeeping requirements in §98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section, as applicable.

(a) If you comply with the CEMS measurement methodology in §98.243(b), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.

(b) If you comply with the mass balance methodology in §98.243(c), then you must retain records of the information listed in paragraphs (b)(1) through (b)(3) of this section.

(1) Results of feedstock or product composition determinations conducted in accordance with §98.243(c)(4).

(2) Start and end times and calculated carbon contents for time periods when off-specification product is produced, if you comply with the alternative methodology in §98.243(c)(4) for determining carbon content of feedstock or product.

(3) A part of the monitoring plan required under §98.3(g)(5), record the estimated accuracy of measurement devices and the technical basis for these estimates.

(c) If you comply with the combustion methodology in §98.243(d), then you must retain under this subpart the records required for the Tier 3 and/or Tier 4 Calculation Methodologies in §98.37.

§98.248 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Product, as used in §98.243, means each of the following carbon-containing outputs from a process: the

petrochemical, recovered byproducts, and liquid organic wastes that are not incinerated onsite. Product does not include process vent emissions, fugitive emissions, or wastewater.

Subpart Y—Petroleum Refineries

§98.250 Definition of Source Category.

(a) A petroleum refinery is any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives, except as provided in paragraph (b) of this section.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure

relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulfur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

§98.251 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.252 GHGs to report.

You must report:

(a) CO₂, CH₄, and N₂O combustion emissions from stationary combustion units and from each flare. Calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C, except for CO₂ emissions from combustion of refinery fuel gas. For CO₂ emissions from combustion of fuel gas, use either equation C-5 in subpart C of this part or the Tier 4 methodology in subpart C of this part. You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in §98.36(c)

when calculating and reporting emissions from stationary combustion units.

(b) CO₂, CH₄, and N₂O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO₂ emissions from sour gas sent off site for sulfur recovery operations under this subpart. You must follow the calculation methodologies from §98.253(f) and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart.

(d) CO₂ process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO₂, CH₄, and N₂O emissions from each coke calcining unit under this subpart.

(f) CO₂ and CH₄ emissions from asphalt blowing operations under this subpart.

(g) CH₄ emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO₂, CH₄, and N₂O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO₂ and CH₄ emissions from non-merchant hydrogen production under this subpart. You must follow the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart P of this part.

§98.253 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in §98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b) (1) through (b) (3) of this section.

(1) Calculate the CO₂ emissions according to the applicable requirements in paragraphs (b) (1) (i) through (b) (1) (iii) of this section.

(i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering

calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare using the applicable methods in paragraphs (b) (1) (ii) (A) and (b) (1) (ii) (B).

(A) If you monitor gas composition, calculate the CO₂ emissions from the flare using Equation Y-1 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-1 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^n \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \text{ (Eq. Y-1)}$$

Where:

CO ₂	=	Annual CO ₂ emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p	=	Measurement period index.

- 44 = Molecular weight of CO₂ (kg/kg-mole).
- 12 = Atomic weight of C (kg/kg-mole).
- (Flare)_p = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "(MW)_p/MVC" with "1".
- (MW)_p = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
- MVC = Molar volume conversion factor (849.5 scf/kg-mole).
- (CC)_p = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(B) If you monitor heat content but do not monitor gas composition, calculate the CO₂ emissions from the flare using Equation Y-2 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-2 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^n [(Flare)_p \times (HHV)_p \times EmF] \quad (\text{Eq. Y-2})$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
- 0.98 = Assumed combustion efficiency of a flare.
- 0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

- n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
- p = Measurement period index.
- (Flare)_p = Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows:

$$\text{Flare}[\text{MMscf}] = 0.000001 \times \text{Flare}[\text{kg}] \times \text{MVC}/(\text{MW})_p$$
 where MVC is the molar volume conversion factor (849.5 scf/kg-mole) and (MW)_p is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
- (HHV)_p = Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
- EmF = Default CO₂ emission factor of 60 kilograms CO₂/MMBtu (HHV basis).

(iii) Alternative to heat value or carbon content measurements. If you do not measure the higher heating value or carbon content of the flare gas at least weekly, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO₂ emissions as specified in paragraphs (b) (1) (iii) (A) through (b) (1) (iii) (C) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process

knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event exceeding 500,000 scf/day.

(B) For periods of normal operation, use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculations.

(C) Calculate the CO₂ emissions using Equation Y-3 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum_{p=1}^n \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)$$

(Eq. Y-3)

Where:

CO ₂	=	Annual CO ₂ emissions for a specific fuel type (metric tons/year).
0.98	=	Assumed combustion efficiency of a flare.
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
Flare _{Norm}	=	Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).
HHV	=	Higher heating value for fuel gas or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).
EmF	=	Default CO ₂ emission factor for flare gas of 60 kilograms CO ₂ /MMBtu (HHV basis).

n	=	Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day.
p	=	Start-up, shutdown, and malfunction event index.
44	=	Molecular weight of CO ₂ (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).
(Flare _{SSM}) _p	=	Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (scf/event).
(MW) _p	=	Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
(CC) _p	=	Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).

(2) Calculate CH₄ using Equation Y-4 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH_4} \quad (\text{Eq. Y-4})$$

Where:

CH ₄	=	Annual methane emissions from flared gas (metric tons CH ₄ /year).
CO ₂	=	Emission rate of CO ₂ from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).
EmF _{CH₄}	=	Default CH ₄ emission factor for "Petroleum Products" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH ₄ /MMBtu).
EmF	=	Default CO ₂ emission factor for flare gas of 60 kg CO ₂ /MMBtu (HHV basis).
0.02/0.98	=	correction factor for flare combustion efficiency.
16/44	=	correction factor ratio of the molecular weight of CH ₄ to CO ₂

f_{CH_4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(3) Calculate N_2O emissions using Equation Y-5 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N_2O}}{EmF} \right) \quad (\text{Eq. Y-5})$$

Where:

N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O /year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).

EmF_{N_2O} = Default N_2O emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg N_2O /MMBtu).

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2 /MMBtu (HHV basis).

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (c)(5) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate and report CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic cracking units

and traditional fluid coking units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Combustion Sources), or follow the requirements of paragraphs (c)(2) or (3) of this section.

(i) Calculate CO₂ emissions by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) If a CO boiler or other post-combustion device is used, you must also calculate the CO₂ emissions from the fuel fired to the CO boiler or post-combustion device using the applicable methods for stationary combustion units in subpart C of this part. Calculate the process emissions from the catalytic cracking unit or fluid coking unit as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the CO boiler.

(2) For catalytic cracking units and fluid coking units with rated capacities greater than 10,000 barrels per stream day (bbls/sd) that do not use a continuous CO₂ CEMS for the final exhaust stack, you must continuously or no less frequently than hourly monitor the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit

burner prior to the combustion of other fossil fuels and calculate the CO₂ emissions according to the requirements of paragraphs (c) (2) (i) through (c) (2) (iii) of this section:

(i) Calculate the CO₂ emissions from each catalytic cracking unit and fluid coking unit using Equation Y-6 of this section.

$$CO_2 = \sum_{p=1}^n \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right] \quad (\text{Eq. Y-6})$$

Where:

- CO₂ = Annual CO₂ mass emissions (metric tons/year).
- Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).
- %CO₂ = Hourly average percent CO₂ concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis).
- %CO = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis). When there is no post-combustion device, assume %CO to be zero.
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole).
- 0.001 = Conversion factor (metric ton/kg).
- n = Number of hours in calendar year.

(ii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the

combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation Y-7 of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. Y-7})$$

Where:

- Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).
- Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
- Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).
- $\%O_2$ = Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis).
- $\%O_{oxy}$ = O_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume - dry basis).
- $\%CO_2$ = Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis).
- $\%CO$ = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required under 40 CFR part 63 subpart UUU, assume $\%CO$ to be zero.

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO₂ emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C and report those emissions by following the requirements of subpart C of this part.

(3) For catalytic cracking units and fluid coking units with rated capacities of 10,000 barrels per stream day (bbls/sd) or less that do not use a continuous CO₂ CEMS for the final exhaust stack, comply with the requirements in paragraphs (c) (3) (i) of this section or paragraphs (c) (3) (ii) and (c) (3) (iii) of this section, as applicable.

(i) If you continuously or no less frequently than daily monitor the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, you must calculate the CO₂ emissions according to the requirements of paragraphs (c) (2) (i) through (c) (2) (iii) of this section, except that daily averages are allowed and the summation can be performed on a daily basis.

(ii) If you do not monitor at least daily the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, calculate the CO₂ emissions from each catalytic cracking unit and fluid coking unit using Equation Y-8 of this section.

$$CO_2 = Q_{unit} \times (CBF \times 0.001) \times CC \times \frac{44}{12} \quad (\text{Eq. Y-8})$$

Where:

CO ₂	= Annual CO ₂ mass emissions (metric tons/year).
Q _{unit}	= Annual throughput of unit from company records (barrels (bbls) per year, bbl/yr).
CBF	= Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11.
0.001	= Conversion factor (metric ton/kg).
CC	= Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
44/12	= Ratio of molecular weight of CO ₂ to C (kg CO ₂ per kg C).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO₂ emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C of this part (General Stationary Fuel Combustion

Sources) and report those emissions by following the requirements of subpart C of this part.

(4) Calculate CH₄ emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-9 of this section.

$$\text{CH}_4 = \left(\text{CO}_2 * \frac{\text{EmF}_2}{\text{EmF}_1} \right) \quad (\text{Eq. Y-9})$$

Where:

- CH₄ = Annual methane emissions from coke burn-off (metric tons CH₄/year).
- CO₂ = Emission rate of CO₂ from coke burn-off calculated in paragraphs (c) (1), (c) (2), (e) (1), (e) (2), (g) (1), or (g) (2) of this section, as applicable (metric tons/year).
- EmF₁ = Default CO₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO₂/MMBtu).
- EmF₂ = Default CH₄ emission factor for "Petroleum Products" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH₄/MMBtu).

(5) Calculate N₂O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-10 of this section.

$$\text{N}_2\text{O} = \left(\text{CO}_2 * \frac{\text{EmF}_3}{\text{EmF}_1} \right) \quad (\text{Eq. Y-10})$$

Where:

- N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O /year).
- CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c) (1), (c) (2), (e) (1), (e) (2), (g) (1), or (g) (2) of this section, as applicable (metric tons/year).
- EmF_1 = Default CO_2 emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO_2 /MMBtu).
- EmF_3 = Default N_2O emission factor for "Petroleum Products" from Table C-2 of subpart C of this part (kg N_2O /MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO_2 emissions using the applicable methods described in paragraphs (e) (1) through (e) (3) of this section and calculate the CH_4 and N_2O emissions using the methods described in paragraphs (c) (4) and (c) (5) of this section, respectively.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO₂ emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic reforming units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (e)(2) or (e)(3) of this section.

(2) If you continuously or no less frequently than daily monitor the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, you must calculate the CO₂ emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO₂ emissions from the catalytic reforming unit catalyst regenerator using Equation Y-11 of this section.

$$CO_2 = \sum_1^n \left[(CB_Q)_n \times CC \times \frac{44}{12} \times 0.001 \right] \quad (\text{Eq. Y-11})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).
 CB_Q = Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).

- n = Number of regeneration cycles in the calendar year.
- CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
- 44/12 = Ratio of molecular weight of CO₂ to C (kg CO₂ per kg C).
- 0.001 = Conversion factor (metric ton/kg).

(f) For on-site sulfur recovery plants, calculate and report CO₂ process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section. Combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part (General Stationary Fuel Combustion Sources). For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(2) through (f)(5) of this section is not considered a fuel.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part, you must calculate CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via

the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the sulfur recovery plant as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack. Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f) (2) through (f) (5) of this section.

(2) Flow measurement. If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(3) Carbon content. If you have a continuous gas composition monitor capable of measuring carbon content on the sour gas feed to the sulfur recovery plant or if you monitor gas composition for carbon content on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon

content factor using limited measurement data or engineering estimates or use the default factor of 0.20.

(4) Calculate the CO₂ emissions from each sulfur recovery plant using Equation Y-12 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \quad (\text{Eq. Y-12})$$

Where:

- CO₂ = Annual CO₂ emissions (metric tons/year).
 F_{SG} = Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant (scf/year).
 44 = Molecular weight of CO₂ (kg/kg-mole).
 MVC = Molar volume conversion factor (849.5 scf/kg-mole).
 MF_C = Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.
 0.001 = Conversion factor, kg to metric tons

(5) If tail gas is recycled to the front of the sulfur recovery plant and the recycled flow rate and carbon content is included in the measured data under paragraphs (f) (2) and (f) (3) of this section, respectively, then the annual CO₂ emissions calculated in paragraph (f) (4) of this section must be corrected to avoid double counting these emissions. You may use engineering estimates to perform this correction or assume that the corrected CO₂ emissions are 95 percent of the uncorrected value calculated using Equation Y-12 of this section.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g) (1) through (g) (3) of this section.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part, you must calculate and report CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a) (4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the coke calcining unit as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the coke calcining unit final exhaust stack. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (g) (2) of this section.

(2) Calculate the CO₂ emissions from the coke calcining unit using Equation Y-13 of this section.

$$CO_2 = \frac{44}{12} * (M_{in} * CC_{GC} - (M_{out} + M_{dust}) * CC_{MPC}) \quad (\text{Eq. Y-13})$$

Where:

- CO₂ = Annual CO₂ emissions (metric tons/year).
- M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).
- CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).
- M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).
- M_{dust} = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year)
- CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- 12 = Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO₂ emissions from the coke calcining unit calculated in paragraphs (g) (1) or (g) (2), as applicable, and calculate CH₄ using the methods described in paragraph (c) (4) of this section and N₂O emissions using the methods described in paragraph (c) (5) of this section.

(h) For asphalt blowing operations, calculate GHG emissions according to the requirements in paragraph (j) of

this section or according to the applicable provisions in paragraphs (h) (1) and (h) (2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO₂ and CH₄ emissions using Equations Y-14 and Y-15 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB,CO_2}) \quad (\text{Eq. Y-14})$$

Where:

CO₂ = Annual CO₂ emissions from uncontrolled asphalt blowing (metric tons CO₂/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CO₂} = Emission factor for CO₂ from uncontrolled asphalt blowing from facility-specific test data (metric tons CO₂/MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH_4}) \quad (\text{Eq. Y-15})$$

Where:

CH₄ = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH₄/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CH₄} = Emission factor for CH₄ from uncontrolled asphalt blowing from facility-specific test data (metric tons CH₄/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO₂ and CH₄ emissions using Equations Y-16 and Y-17 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section or in the stationary combustion unit

emissions required under subpart C of this part (General Stationary Fuel Combustion Sources).

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times \frac{44}{12} \right) \quad (\text{Eq. Y-16})$$

Where:

- CO₂ = Annual CO₂ emissions from controlled asphalt blowing (metric tons CO₂/year).
 0.98 = Assumed combustion efficiency of thermal oxidizer or flare.
 Q_{AB} = Quantity of asphalt blown (MMbbl/year).
 CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.
 44 = Molecular weight of CO₂ (kg/kg-mole).
 12 = Atomic weight of C (kg/kg-mole).

$$CH_4 = 0.02 \times \left(Q_{AB} \times EF_{AB,CH_4} \right) \quad (\text{Eq. Y-17})$$

Where:

- CH₄ = Annual methane emissions from controlled asphalt blowing (metric tons CH₄/year).
 0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
 Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
 EF_{AB,CH₄} = Emission factor for CH₄ from uncontrolled asphalt blowing from facility-specific test data (metric tons CH₄/MMbbl asphalt blown); default = 580.

(i) For delayed coking units, calculate the CH₄ emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (i)(1) or (i)(2), provided no water or steam is added to the vessel once it

is vented to the atmosphere. You must use the method in paragraph (i)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (j) of this section and also calculate the CH₄ emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 14.7)}{14.7} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH_4} \times 0.001 \right) \quad (\text{Eq. Y-18})$$

Where:

- CH₄ = Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).
- N = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
- H = Height of coking unit vessel (feet).
- P_{CV} = Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (i)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (pounds per square inch gauge, psig)
- 14.7 = Assumed atmospheric pressure (pounds per square inch, psi)

f_{void} = Volumetric void fraction of coking vessel prior to steaming (cf gas/cf of vessel); default = 0.6.
 D = Diameter of coking unit vessel (feet).
 16 = Molecular weight of CH_4 (kg/kg-mole).
 MVC = Molar volume conversion factor (849.5 scf/ kg-mole).
 MF_{CH_4} = Mole fraction of methane in coking vessel gas (kg-mole CH_4 /kg-mole gas, wet basis); default value is 0.01.
 0.001 = Conversion factor (metric ton/kg).

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O , calculate GHG emissions using the Equation Y-19 of this section. You must use Equation Y-19 of this section for

catalytic reforming unit depressurization and purge vents when methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (h) (1) or (h) (2) of this section.

$$E_x = \sum_{p=1}^N \left((VR)_p \times (MF_x)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001 \right) \quad (\text{Eq. Y-19})$$

Where:

- E_x = Annual emissions of each GHG from process vent (metric ton/yr).
- N = Number of venting events per year.
- P = Index of venting events.
- $(VR)_p$ = Average volumetric flow rate of process gas during the event (scf per hour).
- $(MF_x)_p$ = Mole fraction of GHG x in process vent during the event (kg-mol of GHG x /kg-mol vent gas).
- MW_x = Molecular weight of GHG x (kg/kg-mole); use 44 for CO_2 or N_2O and 16 for CH_4 .
- MVC = Molar volume conversion factor (849.5 scf/kg-mole).
- $(VT)_p$ = Venting time for the event, (hours).
- 0.001 = Conversion factor (metric ton/kg)

(k) For uncontrolled blowdown systems, you must either use the methods for process vents in paragraph (j) of this section or calculate CH_4 emissions using Equation Y-20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device is considered to be controlled and is not required to estimate emissions under this paragraph (k).

$$CH_4 = \left(Q_{Ref} \times EF_{BD} \times \frac{16}{MVC} \times 0.001 \right) \quad (\text{Eq. Y-20})$$

Where:

- CH₄ = Methane emission rate from blowdown systems (mt CH₄/year).
- Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).
- EF_{BD} = Methane emission factor for uncontrolled blown systems (scf CH₄/MMbbl); default is 137,000.
- 16 = Molecular weight of CH₄ (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole).
- 0.001 = Conversion factor (metric ton/kg).

(1) For equipment leaks, calculate CH₄ emissions using the method specified in either paragraph (1)(1) or (1)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation Y-21 of this section.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \quad (\text{Eq. Y-21})$$

Where:

- CH₄ = Annual methane emissions from equipment leaks (metric tons/year)
- N_{CD} = Number of atmospheric crude oil distillation columns at the facility.
- N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking,

and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.

- N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
- N_{H2} = Total number of hydrogen plants at the facility.
- N_{FGS} = Total number of fuel gas systems at the facility.

(m) For storage tanks, except as provided in paragraph (m) (3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (m) (1) and (m) (2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation Y-22 of this section.

$$CH_4 = (0.1 \times Q_{Ref}) \quad (\text{Eq. Y-22})$$

Where:

- CH₄ = Annual methane emissions from storage tanks (metric tons/year).
- 0.1 = Default emission factor for storage tanks (metric ton CH₄/MMbbl).
- Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH₄ emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y-23 of this section.

$$CH_4 = (995,000 \times Q_{un} \times \Delta P) \times MF_{CH_4} \times \frac{16}{MVC} \times 0.001 \quad (\text{Eq. Y-23})$$

Where:

- CH₄ = Annual methane emissions from storage tanks (metric tons/year).
- Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).
- ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
- MF_{CH₄} = Mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH₄/kg-mole gas); use 0.27 as a default if measurement data are not available.
- 995,000 = Correlation Equation factor (scf gas per MMbbl per psi)
- 16 = Molecular weight of CH₄ (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole).
- 0.001 = Conversion factor (metric ton/kg).

(3) You do not need to calculate CH₄ emissions from storage tanks that meet any of the following descriptions:

(i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(iii) Bottoms receivers or sumps;

(iv) Vessels storing wastewater; or

(v) Reactor vessels associated with a manufacturing process unit.

(n) For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH₄ emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

§98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors associated with stationary combustion sources must follow the monitoring and QA/QC requirements in §98.34.

(b) All flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than stationary combustion sources shall be calibrated according to the procedures in the applicable methods specified in paragraphs (c) through (e) of this section, the procedures specified by the manufacturer, or §98.3(i). Recalibrate each flow meter either biennially (every two years) or at the minimum frequency specified by the manufacturer. Recalibrate each gas composition monitor and heating value monitor either annually or at the minimum frequency specified by the manufacturer.

(c) For flare or sour gas flow meters, operate and maintain the flow meter using any of the following methods, a method published by a consensus-based standards organization (e.g., ASTM, API, etc.) or follow the procedures specified by the flow meter manufacturer. Flow meters must have a rated accuracy of ± 5 percent or lower.

(1) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(2) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(3) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(4) ASME MFC-7M-1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(5) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, see §98.7).

(6) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, see §98.7).

(7) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters (incorporated by reference, see §98.7).

(8) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003) (incorporated by reference, see §98.7).

(d) Determine flare gas composition using any of the following methods.

(1) Method 18 at 40 CFR part 60, appendix A-6.

(2) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(4) GPA 2261-00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(5) UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(e) Determine flare gas higher heating value using any of the following methods.

(1) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).

(2) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).

(3) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural

Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).

(4) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).

(5) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(f) For exhaust gas flow meters used to comply with the requirements in §98.253(c)(2)(ii), install, operate, calibrate, and maintain exhaust gas flow meter according to the requirements in 40 CFR 63.1572(c) or according to the following requirements.

(1) Locate the flow meter(s) and other necessary equipment such as straightening vanes in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(2) Use a flow rate meter with an accuracy within ± 5 percent.

(3) Use a continuous monitoring system capable of correcting for the temperature, pressure, and moisture

content to output flow in dry standard cubic feet (standard conditions as defined in §98.6).

(4) Install, operate, and maintain each continuous monitoring system according to the manufacturer's specifications and requirements.

(g) For exhaust gas CO₂/CO/O₂ composition monitors used to comply with the requirements in §98.253(c)(2), install, operate, calibrate, and maintain exhaust gas composition monitors according to the the requirements in 40 CFR 60.105a(b)(2) or 40 CFR 63.1572(a) or according to the manufacturer's specifications and requirements.

(h) Determine the mass of petroleum coke as required by Equation Y-13 of this subpart using mass measurement equipment meeting the requirements for commercial weighing equipment as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009) (incorporated by reference, see §98.7). Calibrate the measurement device according to the procedures specified by the method, the procedures specified by the manufacturer, or §98.3(i). Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(i) Determine the carbon content of petroleum coke as required by Equation Y-13 of this subpart using any one of

the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.

(1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

(2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(j) Determine the quantity of petroleum process streams using company records. These quantities include the quantity of asphalt blown, quantity of crude oil plus the quantity of intermediate products received from off site, and the quantity of unstabilized crude oil received at the facility.

(k) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including

but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(1) All CO₂ CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in §98.34(c).

§98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in subpart C of this part.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value

is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO₂, CO, O₂, CH₄, or N₂O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

§98.256 Data reporting requirements.

In addition to the reporting requirements of §98.3(c), you must report the information specified in paragraphs (a) through (q) of this section.

(a) For combustion sources, follow the data reporting requirements under subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For hydrogen plants, follow the data reporting requirements under subpart P of this part (Hydrogen Production).

(c) [RESERVED].

(d) [RESERVED].

(e) For flares, owners and operators shall report:

(1) The flare ID number (if applicable).

(2) A description of the type of flare (steam assisted, air-assisted).

(3) A description of the flare service (general facility flare, unit flare, emergency only or back-up flare).

(4) The calculated CO₂, CH₄, and N₂O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO₂ emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y-1 of this subpart, the annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare gas).

(7) If you use Equation Y-2 of this subpart, the annual volume of flare gas combusted (in million (MM)

scf/year) and the annual average higher heating value of the flare gas (in MMBtu per MMscf).

(8) If you use Equation Y-3 of this subpart, the annual volume of flare gas combusted (in MMscf/year) during normal operations, the annual average higher heating value of the flare gas (in MMBtu/MMscf), the number of SSM events exceeding 500,000 scf/day, and the volume of gas flared (in scf/event) and the average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event over 500,000 scf/day.

(9) The fraction of carbon in the flare gas contributed by methane used in Equation Y-4 of this subpart and the basis for its value.

(f) For catalytic cracking units, traditional fluid coking units, and catalytic reforming units, owners and operators shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit).

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) The calculated CO₂, CH₄, and N₂O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO₂ emissions for each unit (e.g., reference section and equation number).

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS (unadjusted to remove CO₂ combustion emissions associated with a CO boiler, if present) and the process CO₂ emissions as calculated according to §98.253(c)(1)(ii). Report the CO₂ annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) If you use Equation Y-6 of this subpart, the annual average exhaust gas flow rate, %CO₂, and %CO.

(8) If you use Equation Y-7 of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %O₂, %O_{oxy}, %CO₂, and %CO.

(9) If you use Equation Y-8 of this subpart, the coke burn-off factor, annual throughput of unit, and the average carbon content of coke and the basis for the value.

(10) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for CH₄ emissions. If you use a unit-specific emission factor for CH₄, report the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(11) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N₂O emissions. If you use a unit-specific emission factor for N₂O, report the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(12) If you use Equation Y-11 of this subpart, the number of regeneration cycles during the reporting year, the average coke burn-off quantity per cycle, and the average carbon content of the coke.

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

- (1) The unit ID number (if applicable).
- (2) A description of the type of unit.

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or §98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO₂, CH₄, and N₂O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in paragraphs (f)(7) through (f)(11) of this section.

(h) For sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery, the owner and operator shall report:

(1) The plant ID number (if applicable).

(2) Maximum rated throughput of each independent sulfur recovery plant, in metric tons sulfur produced/stream day.

(3) The calculated CO₂ annual emissions for each sulfur recovery plant, expressed in metric tons. The calculated annual CO₂ emissions from sour gas sent off-site for sulfur recovery, expressed in metric tons.

(4) If you use Equation Y-12 of this subpart, the annual volumetric flow to the sulfur recovery plant (in

scf/year) and the annual average mole fraction of carbon in the sour gas (in kg-mole C/kg-mole gas).

(5) If you recycle tail gas to the front of the sulfur recovery plant, indicate whether the recycled flow rate and carbon content are included in the measured data under §98.253(f) (2) and (3). Indicate whether a correction for CO₂ emissions in the tail gas was used in Equation Y-12. If so, then report the value of the correction, the annual volume of recycled tail gas (in scf/year) and the annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas). Indicate whether you used the default (95%) or a unit specific correction, and if used, report the approach used.

(6) If you use a CEMS, the relevant information required under §98.36(e) (2) (vi) for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to §98.253(f) (1). Report the CO₂ annual emissions associated with fuel combustion subpart C of this part (General Stationary Fuel Combustion Sources).

(i) For coke calcining units, the owner and operator shall report:

(1) The unit ID number (if applicable).

(2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.

(3) The calculated CO₂, CH₄, and N₂O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(4) A description of the method used to calculate the CO₂ emissions for each unit (e.g., reference section and equation number).

(5) If you use Equation Y-13 of this subpart, annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, and the annual mass of coke dust collected in dust collection systems.

(6) If you use a CEMS, the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to §98.253(g)(1). Report the CO₂ annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).

(7) Indicate whether you use a measured value, a unit-specific emission factor or a default for CH₄ emissions. If you use a unit-specific emission factor for CH₄, the unit-specific emission factor for CH₄, the units of

measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(8) If you use a site-specific emission factor in Equation Y-10 of this subpart, the site-specific emission factor and the basis of the factor.

(j) For asphalt blowing operations, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) The quantity of asphalt blown (in Million bbl) at the facility in the reporting year.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit.

(4) The calculated annual CO₂ and CH₄ emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) If you use Equation Y-14 of this subpart, the CO₂ emission factor used and the basis for the value.

(6) If you use Equation Y-15 of this subpart, the CH₄ emission factor used and the basis for the value.

(7) If you use Equation Y-16 of this subpart, the carbon emission factor used and the basis for the value.

(8) If you use Equation Y-17 of this subpart, the CH₄ emission factor used and the basis for the value.

(k) For delayed coking units, the owner or operator shall report:

(1) The cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for all delayed coking units at the facility.

(2) A description of the method used to calculate the CH₄ emissions for each unit (e.g., reference section and equation number).

(3) The total number of delayed coking units at the facility, the total number of delayed coking drums at the facility, and for each coke drum or vessel: the dimensions, the typical gauge pressure of the coking drum when first vented to the atmosphere, typical void fraction, the typical drum outage (i.e. the unfilled distance from the top of the drum, in feet), and annual number of coke-cutting cycles.

(4) For each set of coking drums that are the same dimensions: the number of coking drums in the set, the height and diameter of the coke drums (in feet), the cumulative number of vessel openings for all delayed coking drums in the set, the typical venting pressure (in psig), void fraction (in cf gas/cf of vessel), and the mole

fraction of methane in coking gas (in kg-mole CF_4 /kg-mole gas, wet basis).

(5) The basis for the volumetric void fraction of the coke vessel prior to steaming and the basis for the mole fraction of methane in the coking gas.

(1) For process vents subject to §98.253(j), the owner or operator shall report:

(1) The vent ID number (if applicable).

(2) The unit or operation associated with the emissions.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(4) The calculated annual CO_2 , CH_4 , and N_2O emissions for each vent, expressed in metric tons of each pollutant emitted.

(5) The annual volumetric flow discharged to the atmosphere (in scf), mole fraction of each GHG above the concentration threshold, and for intermittent vents, the number of venting events and the cumulative venting time.

(m) For uncontrolled blowdown systems, the owner or operator shall report:

(1) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems.

(2) The total quantity (in Million bbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.

(3) The methane emission factor used for uncontrolled blowdown systems and the basis for the value.

(n) For equipment leaks, the owner or operator shall report:

(1) The cumulative CH₄ emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(2) The method used to calculate the reported equipment leak emissions.

(3) The number of each type of emission source listed in Equation Y-21 of this subpart at the facility.

(o) For storage tanks, the owner or operator shall report:

(1) The cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil.

(2) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (AP-42, TANKS 4.09D, Equation Y-22 of this subpart, other).

(3) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.

(4) The cumulative CH₄ emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil.

(5) The method used to calculate the reported storage tank emissions for storage tanks processing unstabilized crude oil.

(6) The quantity of unstabilized crude oil received during the calendar year (in MMbbl), the average pressure differential (in psi), and the mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tank, and the basis for the mole fraction.

(7) The tank-specific methane composition data and the gas generation rate data, if you did not use Equation Y-23.

(p) For loading operations, the owner or operator shall report:

(1) The cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for loading operations.

(2) The quantity and types of materials loaded by vessel type (barge, tanker, marine vessel, etc.) that have

an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.

(3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any (submerged loading, vapor balancing, etc.).

(q) Name of each method listed in §98.254 or a description of manufacturer's recommended method used to determine a measured parameter.

§98.257 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records of all parameters monitored under §98.255.

§98.258 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Z—Phosphoric Acid Production

§98.260 Definition of the source category.

The phosphoric acid production source category consists of facilities with a wet-process phosphoric acid process line used to produce phosphoric acid. A wet-process phosphoric acid process line is the production unit

or units identified by an individual identification number in an operating permit and/or any process unit or group of process units at a facility reacting phosphate rock from a common supply source with acid.

§98.261 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a phosphoric acid production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.262 GHGs to report.

(a) You must report CO₂ process emissions from each wet-process phosphoric acid process line.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C of this part.

§98.263 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each wet-process phosphoric acid process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified

in §98.33(a) (4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions using the procedures in paragraphs (b) (1) and (b) (2) of this section.

(1) Calculate and report the process CO₂ emissions from each wet-process phosphoric acid process line using Equation Z-1 of this section:

$$E_m = \sum_{i=1}^b \sum_{n=1}^z (IC_{n,i} * P_{n,i}) * \frac{2000}{2205} * \frac{44}{12} \quad (\text{Eq. Z-1})$$

Where:

E_m	=	Annual CO ₂ mass emissions from a wet-process phosphoric acid process line m (metric tons).
$IC_{n,i}$	=	Inorganic carbon content of a grab sample batch of phosphate rock by origin i obtained during month n, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
$P_{n,i}$	=	Mass of phosphate rock by origin i consumed in month n by wet-process phosphoric acid process line m (tons).
z	=	Number of months during which the process line m operates.
b	=	Number of different types of phosphate rock in month, by origin. If the grab sample is a composite sample of rock from more than one origin, $b=1$.
2000/2205	=	Conversion factor to convert tons to metric tons.
44/12	=	Ratio of molecular weights, CO ₂ to carbon.

(2) You must determine the total emissions from the facility using Equation Z-2 of this section:

$$CO_2 = \sum_{m=1}^p E_m \quad (\text{Eq. Z-2})$$

Where:

CO_2 = Annual process CO_2 emissions from phosphoric acid production facility (metric tons/year)

E_m = Annual process CO_2 emissions from wet-process phosphoric acid process line m (metric tons/year)

p = Number of wet-process phosphoric acid process lines.

(c) If GHG emissions from a wet-process phosphoric acid process line are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§98.264 Monitoring and QA/QC requirements.

(a) You must obtain a monthly grab sample of phosphate rock directly from the rock being fed to the process line. Conduct the representative bulk sampling

using the applicable standard method in the Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 - Version 1.9 (incorporated by reference, see §98.7). If phosphate rock is obtained from more than one origin in a month, you must obtain a sample from each origin of rock or obtain a composite representative sample.

(b) You must determine the inorganic carbon content of each monthly grab sample of phosphate rock (consumed in the production of phosphoric acid) using the applicable standard method in the Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 - Version 1.9 (incorporated by reference, see §98.7).

(c) You must determine the mass of phosphate rock consumed each month (by origin) in each wet-process phosphoric acid process line. You can use existing plant procedures that are used for accounting purposes (such as sales records) or you can use data from existing monitoring equipment that is used to measure total mass flow of phosphorous-bearing feed under 40 CFR part 60 or part 63. §98.265 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.263(b) is required.

Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the inorganic carbon content of phosphate rock (by origin), you must use the appropriate default factor provided in Table Z-1 of this subpart. Alternatively, the you must determine substitute data value by calculating the arithmetic average of the quality-assured values of inorganic carbon contents of phosphate rock of origin i from samples immediately preceding and immediately following the missing data incident. If no quality-assured data on inorganic carbon contents of phosphate rock of origin i are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for inorganic carbon contents for phosphate rock of origin i obtained after the missing data period.

(b) For each missing value of monthly mass consumption of phosphate rock (by origin), you must use the best available estimate based on all available process data or data used for accounting purposes.

§98.266 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (b) of this section.

(a) Annual phosphoric acid production by origin (as listed in Table Z-1 to this subpart) of the phosphate rock (tons).

(b) Annual phosphoric acid permitted production capacity (tons).

(c) Annual arithmetic average percent inorganic carbon in phosphate rock from monthly records.

(d) Annual phosphate rock consumption from monthly measurement records by origin, (as listed in Table Z-1 to this subpart) (tons).

(e) If you use a CEMS to measure CO₂ emissions, then you must report the information in paragraphs (e)(1) and (e)(2) of this section.

(1) The identification number of each wet-process phosphoric acid process line.

(2) The annual CO₂ emissions from each wet-process phosphoric acid process line (metric tons) and the relevant information required under 40 CFR 98.36 (e)(2)(vi) for the Tier 4 Calculation Methodology.

(f) If you do not use a CEMS to measure emissions, then you must report the information in paragraphs (f)(1) through (f)(8) of this section.

(1) Identification number of each wet-process phosphoric acid process line.

(2) Annual CO₂ emissions from each wet-process phosphoric acid process line (metric tons) as calculated by Equation Z-1 of this subpart.

(3) Annual phosphoric acid permitted production capacity (tons) for each wet-process phosphoric acid process line (metric tons).

(4) Method used to estimate any missing values of inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line.

(5) Monthly inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line (percent by weight, expressed as a decimal fraction).

(6) Monthly mass of phosphate rock consumed by origin, (as listed in Table Z-1 of this subpart) in production for each wet-process phosphoric acid process line (tons).

(7) Number of wet-process phosphoric acid process lines.

(8) Number of times missing data procedures were used to estimate phosphate rock consumption (months) and inorganic carbon contents of the phosphate rock (months).

§98.267 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section for each wet-process phosphoric acid production facility.

(a) Monthly mass of phosphate rock consumed by origin (as listed in Table Z-1 of this subpart) (tons).

(b) Records of all phosphate rock purchases and/or deliveries (if vertically integrated with a mine).

(c) Documentation of the procedures used to ensure the accuracy of monthly phosphate rock consumption by origin, (as listed in Table Z-1 of this subpart).

§98.268 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table Z-1 of Subpart Z—Default Chemical Composition of Phosphate Rock by Origin

Origin	Total Carbon (percent by weight)
Central Florida	1.6
North Florida	1.76
North Carolina (Calcined)	0.76
Idaho (Calcined)	0.60
Morocco	1.56

Subpart AA—Pulp and Paper Manufacturing§98.270 Definition of Source Category.

(a) The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (b)(5) of this section:

(1) Chemical recovery furnaces at kraft and soda mills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and semichemical process).

(2) Chemical recovery combustion units at sulfite facilities.

(3) Chemical recovery combustion units at stand-alone semichemical facilities.

(4) Pulp mill lime kilns at kraft and soda facilities.

(5) Systems for adding makeup chemicals (CaCO_3 , Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

§98.271 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a pulp and paper manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (f) of this section:

(a) CO_2 , biogenic CO_2 , CH_4 , and N_2O emissions from each kraft or soda chemical recovery furnace.

(b) CO_2 , biogenic CO_2 , CH_4 , and N_2O emissions from each sulfite chemical recovery combustion unit.

(c) CO_2 , biogenic CO_2 , CH_4 , and N_2O emissions from each stand-alone semichemical chemical recovery combustion unit.

(d) CO_2 , biogenic CO_2 , CH_4 , and N_2O emissions from each kraft or soda pulp mill lime kiln.

(e) CO_2 emissions from addition of makeup chemicals (CaCO_3 , Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

(f) CO_2 , CH_4 , and N_2O combustion emissions from each stationary combustion unit. You must calculate and report

these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO₂, biogenic CO₂, CH₄, and N₂O emissions using the procedures in paragraphs (a)(1) through (a)(3) of this section. CH₄ and N₂O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(1) Calculate fossil fuel-based CO₂ emissions from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 methodology for stationary combustion sources in §98.33(a)(1).

(2) Calculate fossil fuel-based CH₄ and N₂O emissions from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO₂ equivalent according to the methodology for stationary combustion sources in §98.33(c).

(3) Calculate biogenic CO₂ emissions and emissions of CH₄ and N₂O from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default or

site-specific emissions factors, according to Equation AA-1 of this section:

$$CO_2, CH_4, \text{ or } N_2O \text{ from biomass} = (0.907.18) * Solids * HHV * EF \quad (\text{Eq. AA-1})$$

Where:

$CO_2, CH_4, \text{ or } N_2O,$ from Biomass	=	Biogenic CO_2 emissions or emissions of CH_4 or N_2O from spent liquor solids combustion (metric tons per year).
Solids	=	Mass of spent liquor solids combusted (short tons per year) determined according to §98.274(b).
HHV	=	Annual high heat value of the spent liquor solids (mmBtu per kilogram) determined according to 98.274(b).
EF	=	Default emission factor for $CO_2, CH_4, \text{ or } N_2O,$ from Table AA-1 of this subpart (kg $CO_2, CH_4, \text{ or } N_2O$ per mmBtu).
0.90718	=	Conversion factor from short tons to metric tons.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine $CO_2, CH_4,$ and N_2O emissions using the procedures in paragraphs (b) (1) through (b) (4) of this section:

(1) Calculate fossil CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a) (1).

(2) Calculate CH₄ and N₂O emissions from fossil fuels from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO₂ equivalent according to the methodology for stationary combustion sources in §98.33(c).

(3) Calculate biogenic CO₂ emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to Equation AA-2 of this section:

$$\text{Biogenic CO}_2 = \frac{44}{12} * \text{Solids} * \text{CC} * (0.90718) \quad (\text{Eq. AA-2})$$

Where:

Biogenic CO₂ = Annual CO₂ mass emissions for spent liquor solids combustion (metric tons per year).

Solids = Mass of the spent liquor solids combusted (short tons per year) determined according to §98.274(b).

CC = Annual carbon content of the spent liquor solids, determined according to §98.274(b) (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

44/12 = Ratio of molecular weights, CO₂ to carbon.

0.90718 = Conversion from short tons to metric tons

(4) Calculate CH₄ and N₂O emissions from biomass using Equation AA-1 of this section and the default CH₄ and N₂O emissions factors for kraft facilities in Table AA-1 of this subpart and convert the CH₄ or N₂O emissions to metric tons of CO₂ equivalent by multiplying each annual CH₄ and

N₂O emissions total by the appropriate global warming potential (GWP) factor from Table A-1 of subpart A of this part.

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO₂, CH₄, and N₂O emissions using the procedures in paragraphs (c)(1) through (c)(3) of this section:

(1) Calculate CO₂ emissions from fossil fuel from direct measurement of fossil fuels consumed and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a)(1); use the default HHV listed in Table C-1 of subpart C and the default CO₂ emissions factors listed in Table AA-2 of this subpart.

(2) Calculate CH₄ and N₂O emissions from fossil fuel from direct measurement of fossil fuels consumed, default HHV, and default emissions factors and convert to metric tons of CO₂ equivalent according to the methodology for stationary combustion sources in §98.33(c); use the default HHV listed in Table C-1 of subpart C and the default CH₄ and N₂O emissions factors listed in Table AA-2 of this subpart.

(3) Biogenic CO₂ emissions from conversion of CaCO₃ to CaO are included in the biogenic CO₂ estimates calculated

for the chemical recovery furnace in paragraph (a) (3) of this section.

(d) For makeup chemical use, you must calculate CO₂ emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO₂ and the makeup chemicals, according to Equation AA-3 of this section:

$$CO_2 = \left[M_{(CaCO_3)} * \frac{44}{100} + M_{(Na_2CO_3)} \frac{44}{105.99} \right] * 1000 \text{ kg / metric ton}$$

(Eq. AA-3)

Where:

CO₂ = CO₂ mass emissions from makeup chemicals (kilograms/yr).

M (CaCO₃) = Make-up quantity of CaCO₃ used for the reporting year (metric tons per year).

M (NaCO₃) = Make-up quantity of Na₂CO₃ used for the reporting year (metric tons per year).

44 = Molecular weight of CO₂.

100 = Molecular weight of CaCO₃.

105.99 = Molecular weight of Na₂CO₃.

§98.274 Monitoring and QA/QC requirements.

(a) Each facility subject to this subpart must quality assure the GHG emissions data according to the applicable requirements in §98.34. All QA/QC data must be available for inspection upon request.

(b) Fuel properties needed to perform the calculations in Equations AA-1 and AA-2 of this subpart must be determined according to paragraphs (b) (1) through (b) (3) of this section.

(1) High heat values of black liquor must be determined no less than annually using T684 om-06 Gross Heating Value of Black Liquor, TAPPI (incorporated by reference, see §98.7). If measurements are performed more frequently than annually, then the high heat value used in Equation AA-1 of this subpart must be based on the average of the representative measurements made during the year.

(2) The annual mass of spent liquor solids must be determined using either of the methods specified in paragraph (b) (2) (i) or (b) (2) (ii).

(i) Measure the mass of spent liquor solids annually (or more frequently) using T-650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference in §98.7). If measurements are performed more frequently than annually, then the mass of spent liquor solids used in Equation AA-1 of this subpart must be based on the average of the representative measurements made during the year.

(ii) Determine the annual mass of spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit.

(3) Carbon analyses for spent pulping liquor must be determined no less than annually using ASTM D5373-08

Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7). If measurements using ASTM D5373-08 are performed more frequently than annually, then the spent pulping liquor carbon content used in Equation AA-2 of this subpart must be based on the average of the representative measurements made during the year.

(c) Each facility must keep records that include a detailed explanation of how company records of measurements are used to estimate GHG emissions. The owner or operator must also document the procedures used to ensure the accuracy of the measurements of fuel, spent liquor solids, and makeup chemical usage, including, but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must be recorded and the technical basis for these estimates must be provided. The procedures used to convert spent pulping liquor flow rates to units of mass (i.e., spent liquor solids firing rates) also must be documented.

(d) Records must be made available upon request for verification of the calculations and measurements.

§98.275 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.

(b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.

(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

§98.276 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information in paragraphs (a) through (K) of this section as applicable:

(a) Annual emissions of CO₂, biogenic CO₂, CH₄, biogenic CH₄, N₂O, and biogenic N₂O (metric tons per year).

(b) Annual quantities fossil fuels by type used in chemical recovery furnaces and chemical recovery combustion units in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(c) Annual mass of the spent liquor solids combusted (short tons per year), and basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system).

(d) The high heat value (HHV) of the spent liquor solids used in Equation AA-1 of this subpart (mmBtu per kilogram).

(e) The default emission factor for CO₂, CH₄, or N₂O, used in Equation AA-1 of this subpart (kg CO₂, CH₄, or N₂O per mmBtu).

(f) The carbon content (CC) of the spent liquor solids, used in Equation AA-2 of this subpart (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

(g) Annual quantities of fossil fuels by type used in pulp mill lime kilns in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(h) Make-up quantity of CaCO_3 used for the reporting year (metric tons per year) used in Equation AA-3 of this subpart.

(i) Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year) used in Equation AA-3 of this subpart.

(j) Annual steam purchases (pounds of steam per year).

(k) Annual production of pulp and/or paper products produced (metric tons).

§98.277 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records in paragraphs (a) through (f) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO_2) for each emissions source listed under §98.270(b).

(b) Annual analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(c) Annual analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfite or semichemical pulp facility.

(d) Annual quantity of spent liquor solids combusted in each chemical recovery furnace and chemical recovery combustion unit, and the basis for determining the annual quantity of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system). If an online measurement system is used, you must retain records of the calculations used to determine the annual quantity of spent liquor solids combusted from the continuous measurements.

(e) Annual steam purchases.

(f) Annual quantities of makeup chemicals used.

§98.278 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table AA-1 of Subpart AA—Kraft Pulping Liquor Emissions Factors for Biomass-Based CO₂, CH₄, and N₂O.

Wood Furnish	Biomass-Based Emissions Factors (kg/mmBtu HHV)		
	CO ₂ ^a	CH ₄	N ₂ O
North American Softwood	94.4	0.030	0.005
North American Hardwood	93.7		
Bagasse	95.5		
Bamboo	93.7		
Straw	95.1		

^a Includes emissions from both the recovery furnace and pulp mill lime kiln.

**Table AA-2 of Subpart AA—Kraft Lime Kiln and Calciner
Emissions Factors for Fossil Fuel-Based CO₂, CH₄, and N₂O**

Fuel	Fossil Fuel-Based Emissions Factors (kg/mmBtu HHV)					
	Kraft Lime Kilns			Kraft Calciners		
	CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O
Residual Oil	76.7	0.0027	0	76.7	0.0027	0.0003
Distillate Oil	73.5			73.5		0.0004
Natural Gas	56.0			56.0		0.0001
Biogas	0			0		0.0001

Subpart BB—Silicon Carbide Production

§98.280 Definition of the source category.

Silicon carbide production includes any process that produces silicon carbide for abrasive purposes.

§98.281 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a silicon carbide production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.282 GHGs to report.

You must report:

(a) CO₂ and CH₄ process emissions from all silicon carbide process units or furnaces combined.

(b) CO₂, CH₄, and N₂O emissions from each stationary combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.283 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each silicon carbide process unit or production furnace using the procedures in either paragraph (a) or (b) of this section. You must determine CH₄ process emissions in accordance with the procedures specified in paragraph (d) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(1) Use Equation BB-1 of this section to calculate the facility-specific emissions factor for determining CO₂ emissions. The carbon content must be measured monthly and used to calculate a monthly CO₂ emissions factor:

$$EF_{CO_2,n} = 0.65 * CCF_n * \left(\frac{44}{12} \right) \quad (\text{Eq. BB-1})$$

Where:

$EF_{CO_2,n}$ = CO₂ emissions factor in month n (metric tons CO₂/metric ton of petroleum coke consumed).

- 0.65 = Adjustment factor for the amount of carbon in silicon carbide product (assuming 35 percent of carbon input is in the carbide product).
- CCF_n = Carbon content factor for petroleum coke consumed in month n from the supplier or as measured by the applicable method incorporated by reference in §98.7 according to §98.284(c) (percent by weight expressed as a decimal fraction).
- 44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation BB-2 of this section to calculate annual CO_2 process emissions from all silicone carbide production:

$$CO_2 = \sum_{n=1}^{12} [T_n * EF_{CO_2,n}] * \frac{2000}{2205} \quad (\text{Eq. BB-2})$$

Where:

- CO_2 = Annual CO_2 emissions from silicon carbide production facility (metric tons CO_2).
- T_n = Petroleum coke consumption in month n (tons).
- $EF_{CO_2,n}$ = CO_2 emissions factor from month n (calculated in Equation BB-1 of this section).
- 2000/2205 = Conversion factor to convert tons to metric tons.
- n = Number of month.

(c) If GHG emissions from a silicon carbide production furnace or process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the

calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(d) You must calculate annual process CH₄ emissions from all silicon carbide production combined using Equation BB-3 of this section:

$$CH_4 = \sum_{n=1}^{12} [T_n * 10.2] * \frac{2000}{2205} * 0.001 \quad (\text{Eq. BB-3})$$

Where:

CH₄ = Annual CH₄ emissions from silicon carbide production facility (metric tons CH₄).

T_n = Petroleum coke consumption in month n (tons).

10.2 = CH₄ emissions factor (kg CH₄/metric ton coke).

2000/2205 = Conversion factor to convert tons to metric tons.

0.001 = Conversion factor from kilograms to metric tons.

n = Number of month.

§98.284 Monitoring and QA/QC requirements.

(a) You must measure your consumption of petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly petroleum coke consumption measurements.

(c) For CO₂ process emissions, you must determine the monthly carbon content of the petroleum coke using reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7) and ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content of the petroleum coke using ASTM D3176-89 and ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

§98.285 Procedures for estimating missing data.

For the petroleum coke input procedure in §98.283(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbon

content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the monthly carbon content of petroleum coke, the substitute data value shall be the arithmetic average of the quality-assured values of carbon contents immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of the monthly petroleum coke consumption, the substitute data value shall be the best available estimate of the petroleum coke consumption based on all available process data or information used for accounting purposes (such as purchase records).

§98.286 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified

in paragraphs (a) or (b) of this section, as applicable for each silicon carbide production facility.

(a) If a CEMS is used to measure process CO₂ emissions, you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in §98.36 and the information listed in this paragraph (a):

- (1) Annual consumption of petroleum coke (tons).
- (2) Annual production of silicon carbide (tons).
- (3) Annual production capacity of silicon carbide (tons).

(b) If a CEMS is not used to measure process CO₂ emissions, you must report the information listed in this paragraph (b) for all furnaces combined:

- (1) Monthly consumption of petroleum coke (tons).
- (2) Annual production of silicon carbide (tons).
- (3) Annual production capacity of silicon carbide (tons).

(4) Carbon content factor of petroleum coke from the supplier or as measured by the applicable method in §98.284(c) for each month (percent by weight expressed as a decimal fraction).

(5) Whether carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(6) CO₂ emissions factor calculated for each month (metric tons CO₂/metric ton of petroleum coke consumed).

(7) Sampling analysis results for carbon content of consumed petroleum coke as determined for QA/QC of supplier data under §98.284(d) (percent by weight expressed as a decimal fraction).

(8) Number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months) and petroleum coke consumption (number of months).

§98.287 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each silicon carbide production facility.

(a) If a CEMS is used to measure CO₂ emissions, you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37 and the information listed in this paragraph (a):

- (1) Records of all petroleum coke purchases.
- (2) Annual operating hours.

(b) If a CEMS is not used to measure emissions, you must retain records for the information listed in this paragraph (b):

- (1) Records of all analyses and calculations conducted for reported data listed in §98.286(b).
- (2) Records of all petroleum coke purchases.
- (3) Annual operating hours.

§98.288 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart CC—Soda Ash Manufacturing

§98.290 Definition of the source category.

A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a) through (c) of this section:

- (a) Calcining trona.
- (b) Calcining sodium sesquicarbonate.
- (c) Using a liquid alkaline feedstock process that directly produces CO₂.

In the context of the soda ash manufacturing sector, “calcining” means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§98.291 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a soda ash manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.292 GHGs to report.

You must report:

(a) CO₂ process emissions from each soda ash manufacturing line combined.

(b) CO₂ combustion emissions from each soda ash manufacturing line.

(c) CH₄ and N₂O combustion emissions from each soda ash manufacturing line. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than soda ash manufacturing lines. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.293 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this

subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO₂ emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO₂ emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Use either Equation CC-1 or Equation CC-2 of this section to calculate annual CO₂ process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} [(IC_T)_n * (T_t)_n] * \frac{2000}{2205} * \frac{0.097}{1} \quad (\text{Eq. CC-1})$$

$$E_k = \sum_{n=1}^{12} [(IC_{sa})_n * (T_{sa})_n] * \frac{2000}{2205} * \frac{0.138}{1} \quad (\text{Eq. CC-2})$$

Where:

- E_k = Annual CO₂ process emissions from each manufacturing line, k (metric tons).
- $(IC_T)_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for month n. This represents the ratio of trona to trona ore.
- $(IC_{sa})_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n. This represents the purity of the soda ash produced.
- $(T_t)_n$ = Mass of trona input in month n (tons).
- $(T_{sa})_n$ = Mass of soda ash output in month n (tons).
- 2000/2205 = Conversion factor to convert tons to metric tons.
- 0.097/1 = Ratio of ton of CO₂ emitted for each ton of trona.
- 0.138/1 = Ratio of ton of CO₂ emitted for each ton of soda ash produced.

(3) Site-specific emission factor method. Use

Equations CC-3, CC-4, and CC-5 of this section to determine annual CO₂ process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO₂ emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO₂ emissions as described in paragraphs (b) (3) (i) through (b) (3) (iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in metric tons per hour.

(ii) Using the test data, you must calculate the hourly CO₂ emission rate using Equation CC-3 of this section:

$$ER_{CO_2} = [(C_{CO_2} * 10000) * 2.59 \times 10^{-9} * 44] * (Q * 60) * 4.53 \times 10^{-4} \quad (\text{Eq. CC-3})$$

Where:

ER_{CO_2}	=	CO ₂ mass emission rate (metric tons/hour).
C_{CO_2}	=	Hourly CO ₂ concentration (percent CO ₂) as determined by §98.294(c).
10000	=	Parts per million per percent
2.59×10^{-9}	=	Conversion factor (pounds-mole/dscf/ppm).
44	=	Pounds per pound-mole of carbon dioxide.
Q	=	Stack gas volumetric flow rate per minute (dscfm).
60	=	Minutes per hour
4.53×10^{-4}	=	Conversion factor (metric tons/pound)

(iii) Using the test data, you must calculate a CO₂ emission factor for the process using Equation CC-4 of this section:

$$EF_{CO_2} = \frac{ER_{CO_2}}{(V_t * 4.53 \times 10^{-4})} \quad (\text{Eq. CC-4})$$

Where:

EF_{CO_2}	=	CO ₂ emission factor (metric tons CO ₂ /metric ton of process vent flow from mine water stripper/evaporator).
ER_{CO_2}	=	CO ₂ mass emission rate (metric tons/hour).

V_t = Process vent flow rate from mine water stripper/evaporator during annual performance test (pounds/hour).
 4.53×10^{-4} = Conversion factor (metric tons/pound)

(iv) You must calculate annual CO₂ process emissions from each manufacturing line using Equation CC-5 of this section:

$$E_k = EF_{CO_2} * (V_a * 0.453) * H \quad (\text{Eq. CC-5})$$

Where:

E_k = Annual CO₂ process emissions for each manufacturing line, k (metric tons).
 EF_{CO_2} = CO₂ emission factor (metric tons CO₂/metric ton of process vent flow from mine water stripper/evaporator).
 V_a = Annual process vent flow rate from mine water stripper/evaporator (thousand pounds/hour).
 H = Annual operating hours for the each manufacturing line.
0.453 = Conversion factor (metric tons/thousand pounds).

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO₂, CH₄, and N₂O emissions in the soda ash manufacturing line according to the applicable requirements in subpart C. §98.294 Monitoring and QA/QC requirements.

Section 98.293 provides three different procedures for emission calculations. The appropriate paragraphs (a) through (c) should be used for the procedure chosen.

(a) If you determine your emissions using §98.293(b)(2) (Equation CC-1 of this subpart) you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359-00 (Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see §98.7). ASTM E359-00 (Reapproved 2005)e1 is designed to measure the total alkalinity in soda ash not in trona. The modified method of ASTM E359-00 adjusts the regular ASTM method to express the results in terms of trona. Although ASTM E359-00 (Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO₂ process emissions based on soda ash production (§98.293(b)(2) Equation CC-2 of this subpart), you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359-

00 (Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see §98.7). Although ASTM E359-00 (Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail loadout points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO₂ emissions using the site-specific emission factor method in §98.293(b)(3), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A-2 to measure the CO₂ concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1 or Method 26 at 40 CFR part 60, appendix A-2 to determine the stack gas volumetric flow rate. All QA/QC procedures

specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

(i) Analysis of samples, determination of emissions, and raw data.

(ii) All information and data used to derive the emissions factor(s).

(iii) You must determine the average process vent flow rate from the mine water stripper/evaporater during each test and document how it was determined.

(4) You must also determine the the annual vent flow rate from the mine water stripper/evaporater from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

§98.295 Procedures for estimating missing data.

For the emission calculation methodologies in §98.293(b)(2) and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as

specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.

(c) For each missing value collected during the performance test (hourly CO₂ concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the

calculation and monitoring and QA/QC requirements under §§98.293(b) (3) and 98.294(c).

(d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.

§98.296 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate for each soda ash manufacturing facility.

(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required under §98.36 and the following information in this paragraph (a):

(1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (metric tons).

(2) Annual production of soda ash for each manufacturing line (tons).

(3) Annual production capacity of soda ash for each manufacturing line (tons).

(4) Identification number of each manufacturing line.

(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each manufacturing line.

(2) Annual process CO₂ emissions from each soda ash manufacturing line (metric tons).

(3) Annual production of soda ash (tons).

(4) Annual production capacity of soda ash for each manufacturing line (tons).

(5) Monthly consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(6) Monthly production of soda ash for each manufacturing line (metric tons).

(7) Inorganic carbon content factor of trona or soda ash (depending on use of Equations CC-1 or CC-2 of this subpart) as measured by the applicable method in §98.294(b) or (c) for each month (percent by weight expressed as a decimal fraction).

(8) Whether CO₂ emissions for each manufacturing line were calculated using a trona input method as described in Equation CC-1 of this subpart, a soda ash output method as described in Equation CC-2 of this subpart, or a site-specific emission factor method as described in Equations CC-3 through CC-5 of this subpart.

(9) Number of manufacturing lines located used to produce soda ash.

(10) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method (§98.293(b)(3)) to estimate emissions then you must report the following relevant information:

- (i) Stack gas volumetric flow rate per minute (dscfm)
- (ii) Hourly CO₂ concentration (percent CO₂)
- (iii) CO₂ emission factor (metric tons CO₂/metric tons of process vent flow from mine water stripper/evaporator).
- (iv) CO₂ mass emission rate (metric tons/hour).
- (v) Average process vent flow from mine water stripper/evaporater during performance test (pounds/hour).
- (vi) Annual process vent flow rate from mine stripper/evaporator (thousand pounds/hour).
- (vii) Annual operating hours for each manufacturing line used to produce soda ash using liquid alkaline feedstock (hours).

(11) Number of times missing data procedures were used and for which parameter as specified in this paragraph (b)(11):

- (i) Trona or soda ash (number of months).

(ii) Inorganic carbon contents of trona or soda ash (weeks).

(iii) Process vent flow rate from mine water stripper/evaporator (number of months).

(iv) Stack gas volumetric flow rate during performance test (number of times).

(v) Hourly CO₂ concentration (number of times).

(vi) Average vent process vent flow rate from mine stripper/evaporator during performance test (number of times).

§98.297 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each soda ash manufacturing line.

(a) If a CEMS is used to measure CO₂ emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology specified in subpart C of this part and the information listed in this paragraph

(a):

(1) Monthly production of soda ash (tons)

(2) Monthly consumption of trona or liquid alkaline feedstock (tons)

(3) Annual operating hours (hours).

(b) If a CEMS is not used to measure emissions, then you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for determining all reported data as listed in §98.296(b).

(2) If using Equation CC-1 or CC-2 of this subpart, weekly inorganic carbon content factor of trona or soda ash, depending on method chosen, as measured by the applicable method in §98.294(b) (percent by weight expressed as a decimal fraction).

(3) Annual operating hours for each manufacturing line used to produce soda ash (hours).

(4) You must document the procedures used to ensure the accuracy of the monthly trona consumption or soda ash production measurements including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(5) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method to estimate emissions (§98.293(b)(3)) then you must also retain the following relevant information:

(i) Records of performance test results.

(ii) You must document the procedures used to ensure the accuracy of the annual average vent flow measurements including, but not limited to, calibration of flow rate meters and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.298 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart DD [RESERVED]

Subpart ~~EE~~–Titanium Dioxide Production

§98.310 Definition of the source category.

The titanium dioxide production source category consists of facilities that use the chloride process to produce titanium dioxide.

§98.311 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a titanium dioxide production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.312 GHGs to report.

(a) You must report CO₂ process emissions from each chloride process line as required in this subpart.

(b) You must report under 40 CFR 98, CO₂, CH₄, and N₂O emissions from each stationary combustion unit under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.313 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions for each chloride process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the annual process CO₂ emissions for each chloride process line by determining the mass of calcined petroleum coke consumed in each line as specified in paragraphs (b)(1) through (b)(3) of this section. Use Equation EE-1 of this section to calculate annual combined process CO₂ emissions from all process lines and use Equation EE-2 of this section to calculate annual process CO₂ emissions for each process

line. If your facility generates carbon-containing waste, use Equation EE-3 of this section to estimate the annual quantity of carbon-containing waste generated and its carbon contents according to §98.314(e) and (f):

(1) You must calculate the annual CO₂ process emissions from all process lines at the facility using Equation EE-1 of this section:

$$CO_2 = \sum_{p=1}^m E_p \quad (\text{Eq. EE-1})$$

Where:

CO₂ = Annual CO₂ emissions from titanium dioxide production facility (metric tons/year).

E_p = Annual CO₂ emissions from chloride process line p (metric tons), determined using Equation EE-2 of this section.

p = Process line.

m = Number of separate chloride process lines located at the facility.

(2) You must calculate the annual CO₂ process emissions from each process lines at the facility using Equation EE-2 of this section:

$$E_p = \sum_{n=1}^{12} \frac{44}{12} * C_{p,n} * \frac{2000}{2205} * CCF_n \quad (\text{Eq. EE-2})$$

Where:

E_p = Annual CO₂ mass emissions from chloride process line p (metric tons).

C_{p,n} = Calcined petroleum coke consumption for process line p in month n (tons).

44/12 = Ratio of molecular weights, CO₂ to carbon.

2000/2205 = Conversion of tons to metric tons.
 CCF_n = Carbon content factor for petroleum coke consumed in month n from the supplier or as measured by the applicable method incorporated by reference in §98.7 according to §98.314(c) (percent by weight expressed as a decimal fraction).
 n = Number of month.

(3) If facility generates carbon-containing waste, you must calculate the total annual quantity of carbon-containing waste produced from all process lines using Equation EE-3 of this section and its carbon contents according to §98.314(e) and (f):

$$TWC = \sum_{p=1}^m \sum_{n=1}^{12} WC_{p,n} \quad (\text{Eq. EE-3})$$

Where:

TWC = Annual production of carbon-containing waste from titanium dioxide production facility (tons).
 $WC_{p,n}$ = Production of carbon-containing waste in month n from chloride process line p (tons).
 p = Process line.
 m = Total number of process lines.
 n = Number of month.

(c) If GHG emissions from a chloride process line are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b)

of this section shall not be used to calculate process CO₂ emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§98.314 Monitoring and QA/QC requirements.

(a) You must measure your consumption of calcined petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly calcined petroleum coke consumption measurements.

(c) You must determine the carbon content of the calcined petroleum coke each month based on reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7) and ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and

Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content from a representative sample of the petroleum coke consumed using ASTM D3176-89 and ASTM D5373-08.

(e) You must determine the quantity of carbon-containing waste generated from the each titanium production line dioxide using plant instruments used for accounting purposes including direct measurement weighing the carbon-containing waste not used during the process (by belt scales or a similar device) or through the use of sales records.

(f) You must determine the carbon contents of the carbon-containing waste from each titanium production line on an annual basis by collecting and analyzing a representative sample of the material using ASTM D3176-89 and ASTM D5373-08.

§98.315 Procedures for estimating missing data.

For the petroleum coke input procedure in §98.313(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbon content values, etc.). Therefore, whenever the monitoring

and quality assurance procedures in §98.315 cannot be followed, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (c) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the monthly carbon content of calcined petroleum coke the substitute data value shall be the arithmetic average of the quality-assured values of carbon contents for the month immediately preceding and the month immediately following the missing data incident. If no quality-assured data on carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of the monthly calcined petroleum coke consumption and/or carbon-containing waste, the substitute data value shall be the best available estimate of the monthly petroleum coke consumption based on all available process data or information used for accounting purposes (such as purchase records).

(c) For each missing value of the carbon content of carbon-containing waste, you must conduct a new analysis following the procedures in §98.314(f).

§98.316 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each titanium dioxide production line.

(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36(e) (2) (vi) for the Tier 4 Calculation Methodology and the following information in this paragraph (a).

- (1) Identification number of each process line.
- (2) Annual consumption of calcined petroleum coke (tons).
- (3) Annual production of titanium dioxide (tons).
- (4) Annual production capacity of titanium dioxide (tons).
- (5) Annual production of carbon-containing waste (tons), if applicable.

(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b):

- (1) Identification number of each process line.

(2) Annual CO₂ emissions from each chloride process line (metric tons/year).

(3) Annual consumption of calcined petroleum coke for each process line (tons).

(4) Annual production of titanium dioxide for each process line (tons).

(5) Annual production capacity of titanium dioxide for each process line (tons).

(6) Calcined petroleum coke consumption for each process line for each month (tons).

(7) Annual production of carbon-containing waste for each process line (tons), if applicable.

(8) Monthly production of titanium dioxide for each process line (tons).

(9) Monthly carbon content factor of petroleum coke from the supplier (percent by weight expressed as a decimal fraction).

(10) Whether monthly carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard methods.

(11) Carbon content for carbon-containing waste (percent by weight expressed as a decimal fraction).

(12) If carbon content of petroleum coke is based on self measurement, the ASTM standard methods used.

(13) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under §98.314(d) (percent by weight expressed as a decimal fraction).

(14) Number of separate chloride process lines located at the facility.

(15) The number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months); petroleum coke consumption (number of months); carbon-containing waste generated (number of months); and carbon contents of the carbon-containing waste (number of times during year).

§98.317 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each titanium dioxide production facility.

(a) If a CEMS is used to measure CO₂ emissions, then you must retain under this subpart required for the Tier 4 Calculation Methodology in §98.37 and the information listed in this paragraph (a):

- (1) Records of all calcined petroleum coke purchases.
- (2) Annual operating hours for each titanium dioxide process line.

(b) If a CEMS is not used to measure CO₂ emissions, then you must retain records for the information listed in this paragraph:

(1) Records of all calcined petroleum coke purchases (tons).

(2) Records of all analyses and calculations conducted for all reported data as listed in §98.316(b).

(3) Sampling analysis results for carbon content of consumed calcined petroleum coke (percent by weight expressed as a decimal fraction).

(4) Sampling analysis results for the carbon content of carbon containing waste (percent by weight expressed as a decimal fraction), if applicable.

(5) Monthly production of carbon-containing waste (tons).

(6) You must document the procedures used to ensure the accuracy of the monthly petroleum coke consumption and quantity of carbon-containing waste measurement including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(7) Annual operating hours for each titanium dioxide process line (hours).

§98.318 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart FF [RESERVED]

Subpart GG—Zinc Production

§98.330 Definition of the source category.

The zinc production source category consists of zinc smelters and secondary zinc recycling facilities.

§98.331 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a zinc production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.332 GHGs to report.

You must report:

(a) CO₂ process emissions from each Waelz kiln and electrothermic furnace used for zinc production.

(b) CO₂, CH₄, and N₂O combustion emissions from each Waelz kiln. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(c) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than Waelz kilns. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.333 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions using the procedures specified in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process or combined process and combustion CO₂ emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions by following paragraphs (b)(1) and (b)(2) of this section.

(1) For each Waelz kiln or electrothermic furnace at your facility used for zinc production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into each Waelz kiln and electrothermic furnace at your facility for each year and calculate annual CO₂

process emissions from each affected unit at your facility using Equation GG-1 of this section. For electrothermic furnaces, carbon containing input materials include carbon electrodes and carbonaceous reducing agents. For Waelz kilns, carbon containing input materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R-1 of §98.183.

$$E_{CO_2k} = \frac{44}{12} * \frac{2000}{2205} * [(Zinc)_k * (C_{Zinc})_k + (Flux)_k * (C_{Flux})_k + (Electrode)_k * (C_{Electrode})_k + (Carbon)_k * (C_{Carbon})_k] \quad (\text{Eq. GG-1})$$

Where:

E_{CO_2k}	=	Annual CO ₂ process emissions from individual Waelz kiln or electrothermic furnace "k" (metric tons).
44/12	=	Ratio of molecular weights, CO ₂ to carbon.
2000/2205	=	Conversion factor to convert tons to metric tons.
$(Zinc)_k$	=	Annual mass of zinc bearing material charged to kiln or furnace "k" (tons).
$(C_{Zinc})_k$	=	Carbon content of the zinc bearing material, from the annual carbon analysis for kiln or furnace "k" (percent by weight, expressed as a decimal fraction).
$(Flux)_k$	=	Annual mass of flux materials (e.g., limestone, dolomite) charged to kiln or furnace "k" (tons).
$(C_{Flux})_k$	=	Carbon content of the flux materials charged to kiln or furnace "k", from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

$(\text{Electrode})_k$	=	Annual mass of carbon electrode consumed in kiln or furnace "k" (tons).
$(C_{\text{Electrode}})_k$	=	Carbon content of the carbon electrode consumed in kiln or furnace "k", from the annual carbon analysis (percent by weight, expressed as a decimal fraction).
$(\text{Carbon})_k$	=	Annual mass of carbonaceous materials (e.g., coal, coke) charged to the kiln or furnace "k" (tons).
$(C_{\text{Carbon}})_k$	=	Carbon content of the carbonaceous materials charged to kiln or furnace, "k", from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

(2) You must determine the CO₂ emissions from all of the Waelz kilns or electrothermic furnaces at your facility using Equation GG-2 of this section.

$$\text{CO}_2 = \sum_{k=1}^n E_{\text{CO}_2_k} \quad (\text{Eq. GG-2})$$

Where:

CO_2	=	Annual combined CO ₂ emissions from all Waelz kilns or electrothermic furnaces (tons).
$E_{\text{CO}_2_k}$	=	Annual CO ₂ emissions from each Waelz kiln or electrothermic furnace k calculated using Equation GG-1 of this section (tons).
n	=	Total number of Waelz kilns or electrothermic furnaces at facility used for the zinc production.

(c) If GHG emissions from a Waelz kiln or electrothermic furnace are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General

Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§98.334 Monitoring and QA/QC requirements.

If you determine CO₂ emissions using the carbon input procedure in §98.333(b)(1) and (b)(2), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the mass of each solid carbon-containing input material consumed using facility instruments, procedures, or records used for accounting purposes including direct measurement weighing or through the use of purchase records same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.). Record the total mass for the materials consumed each calendar month and sum the monthly mass to determine the annual mass for each input material.

(b) For each input material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed or used in the calendar year using the methods specified in either paragraph (b) (1) or (b) (2) of this section.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material using the appropriate testing method. For each carbon-containing input material identified for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed at least annually using the appropriate standard methods (and their QA/QC procedures), which are identified in paragraphs (b) (2) (i) through (b) (2) (iii) of this section, as applicable. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(i) Using ASTM E1941-04 Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see §98.7), analyze zinc bearing materials.

(ii) Using ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7), analyze carbonaceous reducing agents and carbon electrodes.

(iii) Using ASTM C25-06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see §98.7), analyze flux materials such as limestone or dolomite.

§98.335 Procedures for estimating missing data.

For the carbon input procedure in §98.333(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in §98.333(b); 100 percent data availability is required. You must repeat the test for

average carbon contents of inputs according to the procedures in §98.335(b) if data are missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in §98.333(b), the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.

§98.336 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable, for each Waelz kiln or electrothermic furnace.

(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in §98.37 and the information listed in this paragraph (a):

- (1) Annual zinc product production capacity (tons).
- (2) Annual production quantity for each zinc product (tons).
- (3) Annual facility production quantity for each zinc product (tons).
- (4) Number of Waelz kilns at each facility used for zinc production.

(5) Number of electrothermic furnaces at each facility used for zinc production.

(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b):

(1) Kiln identification number and annual process CO₂ emissions from each individual Waelz kiln or electrothermic furnace (metric tons).

(2) Annual zinc product production capacity (tons).

(3) Annual production quantity for each zinc product (tons).

(4) Number of Waelz kilns at each facility used for zinc production.

(5) Number of electrothermic furnaces at each facility used for zinc production.

(6) Annual mass of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials (e.g., limestone, dolomite), carbon electrode, and other carbonaceous materials (e.g., coal, coke)) (tons).

(7) Carbon content of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials, and other carbonaceous materials) from the annual carbon analysis for each kiln or

furnace (percent by weight, expressed as a decimal fraction).

(8) Whether carbon content of each carbon-containing input material charged to each kiln or furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(9) If carbon content of each carbon-containing input material charged to each kiln or furnace is based on self measurement, the ASTM Standard Test Method used.

(10) Carbon content of the carbon electrode used in each furnace from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

(11) Whether carbon content of the carbon electrode used in each furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(12) If carbon content of carbon electrode used in each furnace is based on self measurement, the ASTM standard method used.

(13) If you use the missing data procedures in §98.335(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

§98.337 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each zinc production facility.

(a) If a CEMS is used to measure emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37 and the information listed in this paragraph (a):

(1) Monthly facility production quantity for each zinc product (tons).

(2) Annual operating hours for all Waelz kilns and electrothermic furnaces used in zinc production.

(b) If a CEMS is not used to measure emissions, you must also retain the records specified in paragraphs (b) (1) through (b) (7) of this section.

(1) Records of all analyses and calculations conducted for data reported as listed in §98.336(b).

(2) Annual operating hours for Waelz kilns and electrothermic furnaces used in zinc production.

(3) Monthly production quantity for each zinc product (tons).

(4) Monthly mass of zinc bearing materials, flux materials (e.g., limestone, dolomite), and carbonaceous materials (e.g., coal, coke) charged to the kiln or furnace (tons).

(5) Sampling and analysis records for carbon content of zinc bearing materials, flux materials (e.g., limestone, dolomite), carbonaceous materials (e.g., coal, coke), charged to the kiln or furnace (percent by weight, expressed as a decimal fraction).

(6) Monthly mass of carbon electrode consumed in for each electrothermic furnace (tons).

(7) Sampling and analysis records for carbon content of electrode materials.

(8) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each Waelz kiln or electrothermic furnace, as applicable to your facility, including documentation of any materials excluded from Equation GG-1 of this subpart that contribute less than 1 percent of the total carbon inputs to the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an affected unit including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§98.338 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart HH—Municipal Solid Waste Landfills

§98.340 Definition of the source category.

(a) This source category applies to municipal solid waste (MSW) landfills that accepted waste on or after January 1, 1980.

(b) This source category does not include hazardous waste landfills, construction and demolition landfills, or industrial landfills.

(c) This source category consists of the following sources at municipal solid waste (MSW) landfills: landfills, landfill gas collection systems, and landfill gas destruction devices (including flares).

§98.341 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a MSW landfill and the facility meets the requirements of §98.2(a)(1).

§98.342 GHGs to report.

(a) You must report CH₄ generation and CH₄ emissions from landfills.

(b) You must report CH₄ destruction resulting from landfill gas collection and combustion systems.

(c) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C.

§98.343 Calculating GHG emissions.

(a) For all landfills subject to the reporting requirements of this subpart, calculate annual modeled CH₄ generation according to the applicable requirements in paragraphs (a)(1) through (a)(3) of this section.

(1) Calculate annual modeled CH₄ generation using Equation HH-1 of this section.

$$G_{CH_4} = \left[\sum_{x=S}^{T-1} \{ W_x L_{0,x} (e^{-k(T-x-1)} - e^{-k(T-x)}) \} \right] \quad (\text{Eq. HH-1})$$

Where:

G_{CH_4}	=	Modeled methane generation rate in reporting year T (metric tons CH ₄).
X	=	Year in which waste was disposed.
S	=	Start year of calculation. Use the year 50 years prior to the year of the emissions estimate, or the opening year of the landfill, whichever is more recent.
T	=	Reporting year for which emissions are calculated.
W_x	=	Quantity of waste disposed in the landfill in year X from tipping fee receipts or other company records (metric tons, as received (wet weight)).
L_0	=	CH ₄ generation potential (metric tons CH ₄ /metric ton waste) = MCF×DOC×DOC _F ×F×16/12.
MCF	=	Methane correction factor (fraction); default is 1.

DOC	=	Degradable organic carbon from Table HH-1 of this subpart or measurement data, if available [fraction (metric tons C/metric ton waste)].
DOC _F	=	Fraction of DOC dissimilated (fraction); default is 0.5.
F	=	Fraction by volume of CH ₄ in landfill gas from measurement data, if available (fraction); default is 0.5.
k	=	Rate constant from Table HH-1 of this subpart or measurement data, if available (yr ⁻¹).

(2) For years when material-specific waste quantity data are available, apply Equation HH-1 of this section for each waste quantity type and sum the CH₄ generation rates for all waste types to calculate the total modeled CH₄ generation rate for the landfill. Use the appropriate parameter values for k, DOC, MCF, DOC_F, and F shown in Table HH-1 of this subpart. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. You may use the bulk waste parameters for a portion of your waste materials when using the material-specific modeling approach for mixed waste streams that cannot be designated to a specific material type. For years when waste composition data are not available, use the bulk waste parameter values for k and L₀ in Table HH-1 of this subpart for the total quantity of waste disposed in those years.

(3) For years prior to reporting for which waste disposal quantities are not readily available, W_x shall be

estimated using one of the applicable methods in paragraphs (a) (3) (i) through (a) (3) (iii) of this section. You must determine which method is most applicable to the conditions and disposal history of your facility and use that method to estimate waste disposal quantities.

(i) Assume all prior year waste disposal quantities are the same as the waste quantity in the first reporting year.

(ii) Use the estimated population served by the landfill in each year, the values for national average per capita waste generation, and fraction of generated waste disposed of in solid waste disposal sites found in Table HH-2 of this subpart, and calculate the waste quantity landfilled using Equation HH-2 of this section.

$$W_x = POP_x \times WGR_x \times \frac{\%SWDS_x}{100\%} \quad (\text{Eq. HH-2})$$

Where:

- W_x = Quantity of waste placed in the landfill in year x (metric tons, wet basis).
- POP_x = Population of served by the landfill in year x from city population, census data, or other estimates (capita).
- WGR = Average per capita waste generation rate for year x from Table HH-2 of this subpart (metric tons per capita per year, wet basis; tons/cap/yr).
- $\%SWDS$ = Percent of waste generated subsequently managed in solid waste disposal sites (i.e., landfills) for year x from Table HH-2 of this subpart.

(iii) Use a constant average waste disposal quantity calculated using Equation HH-3 of this section for each year the landfill was in operation (i.e., from first accepting waste until the last year for which waste disposal data is unavailable, inclusive).

$$WAR = \frac{LFC}{(YrData - YrOpen + 1)} \quad (\text{Eq. HH-3})$$

Where:

- WAR = Annual average waste acceptance rate (metric tons per year).
- LFC = Landfill capacity or, for operating landfills, capacity of the landfill currently used from design drawings or engineering estimates (metric tons).
- YrData = Year in which the landfill last received waste or, for operating landfills, the year prior to the first reporting year when waste disposal data is first available from company records, or best available data.
- YrOpen = Year in which the landfill first received waste from company records or best available data. If no data are available for estimating YrOpen for a closed landfill, use 30 years as the default operating life of the landfill.

(b) For landfills with gas collection systems, calculate the quantity of CH₄ destroyed according to the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) If you continuously monitor the flow rate, CH₄ concentration, temperature, pressure, and moisture content of the landfill gas that is collected and routed to a

destruction device (before any treatment equipment) using a monitoring meter specifically for CH₄ gas, as specified in §98.344, you must use this monitoring system and calculate the quantity of CH₄ recovered for destruction using Equation HH-4 of this section. A fully integrated system that directly reports CH₄ content requires no other calculation than summing the results of all monitoring periods for a given year.

$$R = \sum_{n=1}^N \left((V)_n \times [1 - (f_{H_2O})_n] \times \frac{(C)_n}{100\%} \times 0.0423 \times \frac{520^\circ R}{(T)_n} \times \frac{(P)_n}{1 \text{ atm}} \times 1,440 \times \frac{0.454}{1,000} \right) \quad (\text{Eq. HH-4})$$

Where:

- R = Annual quantity of recovered CH₄ (metric tons CH₄).
- N = Total number of measurement periods in a year. Use daily averaging periods for continuous monitoring system (N=365). For weekly sampling, use N=52.
- n = Index for measurement period.
- (V)_n = Daily average volumetric flow rate for day n (acfm). If the flow rate meter automatically corrects for temperature and pressure, replace "520°R/(T)_n × (P)_n/1 atm" with "1". If the CH₄ concentration is determined on a dry basis and the flow rate meter automatically corrects for moisture content, replace the term [1-(f_{H2O})_n] with 1.
- (f_{H2O})_n = Daily average moisture content of landfill gas, volumetric basis (cubic feet water per cubic feet landfill gas).
- (C)_n = Daily average CH₄ concentration of landfill gas for day n (volume %, dry basis). If the CH₄ concentration is determined on a wet basis, replace the term [1-(f_{H2O})_n] with 1.

0.0423	=	Density of CH ₄ lb/cf at 520°R or 60°F and 1 atm.
(T) _n	=	Temperature at which flow is measured for day n (°R).
(P) _n	=	Pressure at which flow is measured for day n (atm).
1,440	=	Conversion factor (min/day).
0.454/1,000	=	Conversion factor (metric ton/lb).

(2) If you do not continuously monitor according to paragraph (b)(1) of this section, you must determine the flow rate, CH₄ concentration, temperature, pressure, and moisture content of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) at least weekly according to the requirements in paragraphs (b)(2)(i) through (b)(2)(iii) of this section and calculate the quantity of CH₄ recovered for destruction using Equation HH-4 of this section.

(i) Continuously monitor gas flow rate and determine the cumulative volume of landfill gas each week and the cumulative volume of landfill gas each year that is collected and routed to a destruction device (before any treatment equipment). Under this option, the gas flow meter is not required to automatically correct for temperature, pressure, or, if necessary, moisture content. If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary,

moisture content, you must determine these parameters as specified in paragraph (b) (2) (iii) of this section.

(ii) Determine the CH₄ concentration in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter no less than weekly.

(iii) If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content:

(A) Determine the temperature, pressure in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter no less than weekly.

(B) If the CH₄ concentration is determined on a dry basis, determine the moisture content in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter no less than weekly

(c) Calculate CH₄ generation (adjusted for oxidation in cover materials) and actual CH₄ emissions (taking into account any CH₄ recovery, and oxidation in cover materials)

according to the applicable methods in paragraphs (c) (1) through (c) (3) of this section.

(1) Calculate CH₄ generation, adjusted for oxidation, from the modeled CH₄ (G_{CH₄} from Equation HH-1 of this section) using Equation HH-5 of this section.

$$MG = G_{CH_4} \times (1 - OX) \quad (\text{Eq. HH-5})$$

Where:

MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH₄).

G_{CH₄} = Modeled methane generation rate in reporting year from Equation HH-1 of this section (metric tons CH₄).

OX = Oxidation fraction. Use the default value of 0.1 (10%).

(2) For landfills that do not have landfill gas collection systems, the CH₄ emissions are equal to the CH₄ generation (MG) calculated in Equation HH-5 of this section.

(3) For landfills with landfill gas collection systems, calculate CH₄ emissions using the methodologies specified in paragraphs (c) (3) (i) and (c) (3) (ii) of this section.

(i) Calculate CH₄ emissions from the modeled CH₄ generation and measured CH₄ recovery using Equation HH-6 of this section.

$$\text{Emissions} = [(G_{CH_4} - R) \times (1 - OX) + R \times (1 - (DE \times f_{Dest}))] \quad (\text{Eq. HH-6})$$

Where:

- Emissions = Methane emissions from the landfill in the reporting year (metric tons CH₄).
- G_{CH4} = Modeled methane generation rate in reporting year from Equation HH-1 of this section or the quantity of recovered CH₄ from Equation HH-4 of this section, whichever is greater (metric tons CH₄).
- R = Quantity of recovered CH₄ from Equation HH-4 of this section (metric tons).
- OX = Oxidation fraction. Use the oxidation fraction default value of 0.1 (10%).
- DE = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.
- f_{Dest} = Fraction of hours the destruction device was operating (annual operating hours/8760 hours per year). If the gas is destroyed in a back-up flare (or similar device) or if the gas is transported off-site for destruction, use f_{Dest} = 1.

(ii) Calculate CH₄ generation and CH₄ emissions using measured CH₄ recovery and estimated gas collection efficiency and Equations HH-7 and HH-8 of this section.

$$MG = \frac{R}{CE \times f_{Rec}} \times (1 - OX) \quad (\text{Eq. HH-7})$$

$$\text{Emissions} = \left[\left(\frac{R}{CE \times f_{Rec}} - R \right) \times (1 - OX) + R \times (1 - (DE \times f_{Dest})) \right] \quad (\text{Eq. HH-8})$$

Where:

- MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH₄).
- Emissions = Methane emissions from the landfill in the reporting year (metric tons CH₄).
- R = Quantity of recovered CH₄ from Equation HH-4 of this section (metric tons CH₄).

CE	= Collection efficiency estimated at landfill, taking into account system coverage, operation, and cover system materials from Table HH-3 of this subpart. If area by soil cover type information is not available, use default value of 0.75 (CE4 in table HH-3 of this subpart) for all areas under active influence of the collection system.
f_{Rec}	= Fraction of hours the recovery system was operating (annual operating hours/8760 hours per year).
OX	= Oxidation fraction. Use the oxidation fractions default value of 0.1 (10%).
DE	= Destruction efficiency, (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.
f_{Dest}	= Fraction of hours the destruction device was operating (device operating hours/8760 hours per year). If the gas is destroyed in a back-up flare (or similar device) or if the gas is transported off-site for destruction, use $f_{\text{Dest}} = 1$.

§98.344 Monitoring and QA/QC requirements.

(a) The quantity of waste landfilled must be determined using mass measurement equipment meeting the requirements for commercial weighing equipment as described in "Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices" NIST Handbook 44 (2009) (incorporated by reference, see §98.7).

(b) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH₄ in the recovered landfill gas using one of the methods specified in paragraphs (b)(1) through (b)(6) of this

section or as specified by the manufacturer. Gas composition monitors shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent, or whenever the error in the midrange calibration check exceeds +/- 10 percent.

(1) Method 18 at 40 CFR part 60, appendix A-6.

(2) ASTM D1945-03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(4) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(5) UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(6) As an alternative to the gas chromatography methods provided in paragraphs (b)(1) through (b)(5) of this section, you may use total gaseous organic concentration analyzers and calculate the methane concentration following the requirements in paragraphs (b)(6)(i) through (b)(6)(iii) of this section.

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A-7 to determine total gaseous organic concentration. You must calibrate the instrument with methane and determine the total gaseous organic concentration as carbon (or as methane; $K=1$ in Equation 25A-1 of Method 25A at 40 CFR part 60, appendix A-7).

(ii) Determine a non-methane organic carbon correction factor no less frequently than once a reporting year following the requirements in paragraphs (b)(6)(ii)(A) through (b)(6)(ii)(C) of this section.

(A) Take a minimum of three grab samples of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) with a minimum of 20 minutes between samples and determine the methane composition of the landfill gas using one of the methods specified in paragraphs (b)(1) through (b)(5) of this section.

(B) As soon as practical after each grab sample is collected and prior to the collection of a subsequent grab sample, determine the total gaseous organic concentration of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) using either Method 25A or 25B at 40 CFR part 60, appendix A-7 as specified in paragraph (b)(6)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average total gaseous organic concentration of the samples analyzed according to paragraphs (b) (6) (ii) (A) and (b) (6) (ii) (B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration. If the ratio exceeds 1, use 1 for the non-methane organic carbon correction factor.

(iii) Calculate the methane concentration as specified in Equation HH-9 of this section.

$$C_{CH_4} = f_{NMOC} \times C_{TGOC} \quad (\text{Eq. HH-9})$$

Where:

C_{CH_4}	=	Methane concentration in the landfill gas (volume %).
f_{NMOC}	=	Non-methane organic carbon correction factor from the most recent determination of the non-methane organic carbon correction factor as specified in paragraph (b) (6) (ii) of this section (unitless).
C_{TGOC}	=	Total gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A-7 during routine monitoring of the landfill gas (volume %).

(c) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate of the recovered landfill gas using one of the methods specified

in paragraphs (c) (1) through (c) (8) of this section or as specified by the manufacturer. Each gas flow meter shall be calibrated prior to the first year of reporting and recalibrated either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Except as provided in §98.343(b) (2) (i), each gas flow meter must be capable of correcting for the temperature and pressure and, if the gas composition monitor determines CH₄ concentration on a dry basis, moisture content.

(1) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(2) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(3) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(4) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(5) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, see §98.7). The mass flow must be corrected to

volumetric flow based on the measured temperature, pressure, and gas composition.

(6) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, see §98.7).

(7) ASME MFC-18M-2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, see §98.7).

(8) Method 2A or 2D at 40 CFR part 60, appendix A-1.

(d) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(e) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of disposal quantities and, if applicable, gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§98.345 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore,

whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraphs (a) through (c) of this section.

(a) For each missing value of the CH₄ content, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(b) For missing gas flow rates, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-

assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing daily waste disposal quantity data for disposal in reporting years, the substitute value shall be the average daily waste disposal quantity for that day of the week as measured on the week before and week after the missing daily data.

§98.346 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information for each landfill.

(a) A classification of the landfill as "open" (actively received waste in the reporting year) or "closed" (no longer receiving waste), the year in which the landfill first started accepting waste for disposal, the last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure), the capacity (in metric tons) of the landfill, an indication of whether leachate recirculation is used, and the waste disposal quantity for each year of landfilling.

(b) Method for estimating waste disposal quantity, and reason for its selection.

(c) Waste composition for each year of landfilling, if available, in percentage categorized as:

(1) Municipal.

(2) Biosolids or biological sludges.

(3) Other, or more refined categories, such as those for which k rates are available in Table HH-1 of this subpart, and the method or basis for estimating waste composition.

(d) For each waste type used to calculate CH_4 generation using Equation HH-1 of this subpart, you must report:

(1) Degradable organic carbon (DOC) value used in the calculations.

(2) Decay rate (k) value used in the calculations.

(e) Fraction of CH_4 in landfill gas (F) and an indication of whether the fraction of CH_4 was determined based on measured values or the default value.

(f) The surface area of the landfill containing waste (in square meters), the cover types applicable to the landfill, the surface area and oxidation fraction for each cover type used to calculate the average oxidation fraction, and the average oxidation fraction used in the calculations.

(g) The modeled annual methane generation rate for the reporting year (metric tons CH₄) calculated using Equation HH-1 of this subpart.

(h) For landfills without gas collection systems, the annual methane emissions (i.e., the methane generation, adjusted for oxidation, calculated using Equation HH-5 of this subpart), reported in metric tons CH₄.

(i) For landfills with gas collection systems, you must report:

(1) Total volumetric flow of landfill gas collected for destruction (cubic feet at 520°R or 60°F and 1 atm).

(2) CH₄ concentration of landfill gas collected for destruction (percent by volume).

(3) Monthly average temperature for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature is incorporated into internal calculations run by the monitoring equipment.

(4) Monthly average pressure for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature is incorporated into internal calculations run by the monitoring equipment.

(5) An indication of whether destruction occurs at the landfill facility or off-site. If destruction occurs at the landfill facility, also report an indication of

whether a back-up destruction device is present at the landfill, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), and the destruction efficiency used (percent).

(6) Annual quantity of recovered CH_4 (metric tons CH_4) calculated using Equation HH-4 of this subpart.

(7) A description of the gas collection system (manufacture, capacity, number of wells, etc.), the surface area (square meters) and estimated waste depth (meters) for each area specified in Table HH-3 of this subpart, the estimated gas collection system efficiency for landfills with this gas collection system, and the annual operating hours of the gas collection system.

(8) Methane generation corrected for oxidation calculated using Equation HH-5 of this subpart, reported in metric tons CH_4 .

(9) Methane generation (G_{CH_4}) value used as an input to Equation HH-6 of this subpart. Specify whether the value is modeled (G_{CH_4} from HH-1 of this subpart or measured (R from Equation HH-4 of this subpart)).

(10) Methane generation corrected for oxidation calculated using Equation HH-7 of this subpart, reported in metric tons CH_4 .

(11) Methane emissions calculated using Equation HH-6 of this subpart, reported in metric tons CH₄.

(12) Methane emissions calculated using Equation HH-8 of this subpart, reported in metric tons CH₄.

§98.347 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration.

§98.348 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table HH-1 of Subpart HH—Emissions Factors, Oxidation Factors and Methods

Factor	Default value	Units
Waste model-- bulk waste option		
k (precipitation <20 inches/year and no leachate recirculation)	0.02	yr ⁻¹
k (precipitation 20-40 inches/year and no leachate recirculation)	0.038	yr ⁻¹
k (precipitation >40 inches/year or for landfill areas with leachate recirculation)	0.057	yr ⁻¹
L ₀ (Equivalent to DOC = 0.2028 when MCF=1, DOC _F =0.5, and F=0.5)	0.067	metric tons CH ₄ / metric ton waste
Waste model--All MSW landfills		
MCF	1	
DOC _F	0.5	
F	0.5	

Factor	Default value	Units
Waste model-MSW using waste composition option		
DOC (food waste)	0.15	Weight fraction, wet basis
DOC (garden)	0.2	Weight fraction, wet basis
DOC (paper)	0.4	Weight fraction, wet basis
DOC (wood and straw)	0.43	Weight fraction, wet basis
DOC (textiles)	0.24	Weight fraction, wet basis
DOC (diapers)	0.24	Weight fraction, wet basis
DOC (sewage sludge)	0.05	Weight fraction, wet basis
DOC (bulk waste)	0.20	Weight fraction, wet basis
k (food waste)	0.06 to 0.185 ^a	yr ⁻¹
k (garden)	0.05 to 0.10 ^a	yr ⁻¹
k (paper)	0.04 to 0.06 ^a	yr ⁻¹
k (wood and straw)	0.02 to 0.03 ^a	yr ⁻¹
k (textiles)	0.04 to 0.06 ^a	yr ⁻¹
k (diapers)	0.05 to 0.10 ^a	yr ⁻¹
k (sewage sludge)	0.06 to 0.185 ^a	yr ⁻¹
Calculating methane generation and emissions		
OX	0.1	
DE	0.99	

^a Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate and leachate recirculation is not used. Use the greater value when the potential evapotranspiration rate does not exceed the mean annual precipitation rate or when leachate recirculation is used.

Table HH-2 of Subpart HH-U.S. Per Capita Waste Disposal Rates

Year	Waste per capita ton/cap/yr	% to SWDS
1950	0.63	100
1951	0.63	100
1952	0.63	100
1953	0.63	100
1954	0.63	100
1955	0.63	100

Year	Waste per capita ton/cap/yr	% to SWDS
1956	0.63	100
1957	0.63	100
1958	0.63	100
1959	0.63	100
1960	0.63	100
1961	0.64	100
1962	0.64	100
1963	0.65	100
1964	0.65	100
1965	0.66	100
1966	0.66	100
1967	0.67	100
1968	0.68	100
1969	0.68	100
1970	0.69	100
1971	0.69	100
1972	0.70	100
1973	0.71	100
1974	0.71	100
1975	0.72	100
1976	0.73	100
1977	0.73	100
1978	0.74	100
1979	0.75	100
1980	0.75	100
1981	0.76	100
1982	0.77	100
1983	0.77	100
1984	0.78	100
1985	0.79	100
1986	0.79	100
1987	0.80	100
1988	0.80	100
1989	0.85	84
1990	0.84	77
1991	0.78	76
1992	0.76	72
1993	0.78	71
1994	0.77	67
1995	0.72	63
1996	0.71	62
1997	0.72	61
1998	0.78	61
1999	0.78	60
2000	0.84	61
2001	0.95	63

Year	Waste per capita ton/cap/yr	% to SWDS
2002	1.06	66
2003	1.06	65
2004	1.06	64
2005	1.06	64
2006	1.06	64

Table HH-3 of Subpart HH—Landfill Gas Collection Efficiencies

Description	Landfill Gas Collection Efficiency
A1: Area with no waste in-place	Not applicable; do not use this area in the calculation
A2: Area without active gas collection, regardless of cover type. H2: Average depth of waste in area A2	CE2: 0%
A3: Area with daily soil cover and active gas collection H3: Average depth of waste in area A3	CE3: 60%
A4: Area with an intermediate soil cover and active gas collection H4: Average depth of waste in area A4	CE4: 75%
A5: Area with a final soil and geomembrane cover system and active gas collection H5: Average depth of waste in area A5	CE5: 95%
Area weighted average collection efficiency for landfills.	$CE_{ave1} = (A2*CE2 + A3*CE3 + A4*CE4 + A5*CE5) / (A2+A3+A4+A5)$

Subpart II [RESERVED]

Subpart JJ—Manure Management

§98.360 Definition of the source category.

(a) This source category consists of livestock facilities with manure management systems that emit 25,000 metric tons CO₂e or more per year.

(1) Table JJ-1 presents the minimum average annual animal population by animal group that is estimated to emit 25,000 metric tons CO₂e or more per year. Facilities with

an average annual animal population, as described in §98.363(a) (i) and (ii), below those listed in Table JJ-1 do not need to report under this rule. A facility with an annual animal population that exceeds those listed in Table JJ-1 should conduct a more thorough analysis to determine applicability.

(2) If a facility has more than one animal group present (e.g., swine and poultry), the facility must determine if they are required to report by calculating the combined animal group factor (CAGF) using equation JJ-1:

$$\text{CAGF} = \sum_{\text{Animal Groups}} \left(\frac{\text{AAAP}_{\text{AG, Facility}}}{\text{APTL}_{\text{AG}}} \right) \quad (\text{Eq. JJ-1})$$

Where:

CAGF = Combined Animal Group Factor
 AAAP_{AG, Facility} = Average annual animal population at the facility, by animal group
 APTL_{AG} = Animal population threshold level, as specified in Table JJ-1 of this section

If the calculated CAGF for a facility is less than 1, the facility is not required to report under this rule. If the CAGF is equal to or greater than 1, the facility must use more detailed applicability tables and tools to determine if they are required to report under this rule.

(b) A manure management system (MMS) is a system that stabilizes and/or stores livestock manure, litter, or manure wastewater in one or more of the following system

components: uncovered anaerobic lagoons, liquid/slurry systems with and without crust covers (including but not limited to ponds and tanks), storage pits, digesters, solid manure storage, dry lots (including feedlots), high-rise houses for poultry production (poultry without litter), poultry production with litter, deep bedding systems for cattle and swine, manure composting, and aerobic treatment.

(c) This source category does not include system components at a livestock facility that are unrelated to the stabilization and/or storage of manure such as daily spread or pasture/range/paddock systems or land application activities or any method of manure utilization that is not listed in §98.360 (b).

(d) This source category does not include manure management activities located off site from a livestock facility or off-site manure composting operations.

§98.361 Reporting threshold.

Livestock facilities must report GHG emissions under this subpart if the facility meets the reporting threshold as defined in 98.360(a) above, contains a manure management system as defined in 98.360(b) above, and meets the requirements of §98.2(a)(1).

§98.362 GHGs to report.

(a) Livestock facilities must report annual aggregate CH₄ and N₂O emissions for the following MMS components at the facility:

- (1) Uncovered anaerobic lagoons.
- (2) Liquid/slurry systems (with and without crust covers, and including but not limited to ponds and tanks).
- (3) Storage pits.
- (4) Digesters, including covered anaerobic lagoons.
- (5) Solid manure storage.
- (6) Dry lots, including feedlots.
- (7) High-rise houses for poultry production (poultry without litter)
- (8) Poultry production with litter.
- (9) Deep bedding systems for cattle and swine.
- (10) Manure composting.
- (11) Aerobic treatment.

(b) A livestock facility that is subject to this rule only because of emissions from manure management system components is not required to report emissions from subparts C through PP (other than subpart JJ) of this part.

(c) A livestock facility that is subject to this part because of emissions from source categories described in subparts C through PP of this part is not required to report emissions under subpart JJ of this part unless

emissions from manure management systems are 25,000 metric tons CO₂e per year or more.

§98.363 Calculating GHG emissions.

(a) For all manure management system components listed in 98.360(b) except digesters, estimate the annual CH₄ emissions and sum for all the components to obtain total emissions from the manure management system for all animal types using Equation JJ-1.

$$\text{CH}_4 \text{ Emissions}_{\text{MMS}} \text{ (metric tons/yr)} = \sum_{\text{animal types}} [\sum_{\text{MMSC}} [(\text{TVS}_{\text{AT}} \times \text{VS}_{\text{MMSC}} \times (1 - \text{VS}_{\text{SS}}) \times 365 \text{ days/yr} \times (\text{B}_0)_{\text{AT}} \times \text{MCF}_{\text{MMSC}}) \times 0.662 \text{ kg CH}_4/\text{m}^3 \times 1 \text{ metric ton}/1000 \text{ kg}] \text{ (Eq. JJ-2)}$$

Where:

- MMSC = Manure management systems component.
- TVS_{AT} = Total volatile solids excreted by animal type, calculated using Equation JJ-3 of this section (kg/day).
- VS_{MMSC} = Fraction of the total manure for each animal type that is managed in MMS component MMSC, assumed to be equivalent to the fraction of VS in each MMS component.
- VS_{SS} = Volatile solids removal through solid separation; if solid separation occurs prior to the MMS component, use a default value from Table JJ-4 of this section; if no solid separation occurs, this value is set to 0.
- (B₀)_{AT} = Maximum CH₄-producing capacity for each animal type, as specified in Table JJ-2 of this section (m³ CH₄/kg VS).
- MCF_{MMSC} = CH₄ conversion factor for the MMS component, as specified in Table JJ-5 of this section (decimal).

$$\text{TVS}_{\text{AT}} = \text{Population}_{\text{AT}} \times \text{TAM}_{\text{AT}} \times \text{VS}_{\text{AT}} / 1000 \quad (\text{Eq. JJ-3})$$

Where:

TVS _{AT}	=	Daily total volatile solids excreted per animal type (kg/day).
Population _{AT}	=	Average annual animal population contributing manure to the manure management system by animal type (head) (see description in §98.363(a) (i) and (ii) below).
TAM _{AT}	=	Typical animal mass for each animal type, using either default values in Table JJ-2 of this section or farm-specific data (kg/head).
VS _{AT}	=	Volatile solids excretion rate for each animal type, using default values in Table JJ-2 or JJ-3 of this section (kg VS/day/1000 kg animal mass).

(i) Average annual animal populations for static populations (e.g., dairy cows, breeding swine, layers) must be estimated by performing an animal inventory or review of facility records once each reporting year.

(ii) Average annual animal populations for growing populations (meat animals such as beef and veal cattle, market swine, broilers, and turkeys) must be estimated each year using the average number of days each animal is kept at the facility and the number of animals produced annually, and an equation similar or equal to Equation JJ-4 below, adapted from Equation 10.1 in *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 4, Chapter 10.

$$\text{Population}_{\text{AT}} = \text{Days onsite}_{\text{AT}} \times \left(\frac{\text{NAPA}_{\text{AT}}}{365} \right) \quad (\text{Eq. JJ-4})$$

Where:

Population_{AT} = Average annual animal population (by animal type).

Days onsite_{AT} = Average number of days the animal is kept at the facility, by animal type.

NAPA_{AT} = Number of animals produced annually, by animal type.

(b) For each digester, calculate the total amount of CH₄ emissions, and then sum the emissions from all digesters, as shown in Equation JJ-5 of this section.

$$H_4 \text{ Emissions}_{AD} = \sum_1^{AD} (CH_4C - CH_4D + CH_4L) \quad (\text{Eq- JJ-5})$$

Where:

CH₄ Emissions_{AD} = CH₄ emissions from anaerobic digestion (metric tons/yr).

AD = Number of anaerobic digesters at the manure management facility.

CH₄C = CH₄ flow to digester combustion device, calculated using Equation JJ-6 of this section (metric tons CH₄/yr).

CH₄D = CH₄ destruction at digesters, calculated using Equation JJ-11 of this section (metric tons CH₄/yr).

CH₄L = Leakage at digesters calculated using Equation JJ-12 of this section (metric tons CH₄/yr).

(1) For each digester, calculate the annual CH₄ flow to the combustion device (CH₄C) using Equation JJ-6 of this section. A fully integrated system that directly reports the quantity of CH₄ flow to the digester combustion device requires only summing the results of all monitoring periods for a given year to obtain CH₄C.

$$\text{CH}_4\text{C} = \left(V \times \frac{C}{100\%} \times 0.0423 \times \frac{520^\circ\text{R}}{T} \times \frac{P}{1 \text{ atm}} \times \frac{0.454 \text{ metric ton}}{1,000 \text{ pounds}} \right) \quad (\text{Eq. JJ-6})$$

Where:

- CH_4C = CH_4 flow to digester combustion device (metric tons CH_4/yr).
- V = Average annual volumetric flow rate, calculated in Equation JJ-7 of this subsection (cubic feet CH_4/yr).
- C = Average annual CH_4 concentration of digester gas, calculated in Equation JJ-8 of this section (% wet basis).
- 0.0423 = Density of CH_4 lb/scf (at 520°R or 60°F and 1 atm).
- T = Average annual temperature at which flow is measured, calculated in Equation JJ-9 of this section ($^\circ\text{R}$).
- P = Average annual pressure at which flow is measured, calculated in Equation JJ-10 of this section (atm).

(2) For each digester, calculate the average annual volumetric flow rate, CH_4 concentration of digester gas, temperature, and pressure at which flow are measured using Equations JJ-7 through JJ-10 of this section.

$$V = \frac{\sum_{n=1}^{\text{OD}} \left(V_n \times \frac{1,440 \text{ minutes}}{\text{day}} \right)}{\text{OD}} \quad (\text{Eq. JJ-7})$$

Where:

- V = Average annual volumetric flow rate (cubic feet CH_4/yr).
- OD = Operating days, number of days per year that the digester was operating (days/yr).
- V_n = Daily average volumetric flow rate for day n , as determined from daily monitoring as specified in §98.364 (acfm).

$$C = \frac{\sum_{n=1}^{OD} C_n}{OD} \quad (\text{Eq. JJ-8})$$

Where:

- C = Average annual CH₄ concentration of digester gas (% , wet basis).
- OD = Operating days, number of days per year that the digester was operating (days/yr).
- C_n = Average daily CH₄ concentration of digester gas for day n, as determined from daily monitoring as specified in §98.364 (% , wet basis).

$$T = \frac{\sum_{n=1}^{OD} T_n}{OD} \quad (\text{Eq. JJ-9})$$

Where:

- T = Average annual temperature at which flow is measured (°R).
- OD = Operating days, number of days per year that the digester was operating (days/yr).
- T_n = Temperature at which flow is measured for day n (°R).

$$P = \frac{\sum_{n=1}^{OD} P_n}{OD} \quad (\text{Eq. JJ-10})$$

Where:

- P = Average annual pressure at which flow is measured (atm).
- OD = Operating days, number of days per year that the digester was operating (days/yr).
- P_n = Pressure at which flow is measured for day n (atm).

(3) For each digester, calculate the CH₄ destruction at the digester combustion device using Equation JJ-11 of this section.

$$CH_4D = CH_4C \times DE \times OH/Hours \quad (\text{Eq. JJ-11})$$

Where:

- CH₄D = CH₄ destruction at digester combustion device (metric tons/yr).

- CH₄C = Annual quantity of CH₄ flow to digester combustion device, as calculated in Equation JJ-6 of this section (metric tons CH₄).
- DE = CH₄ destruction efficiency from flaring or burning in engine (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.
- OH = Number of hours combustion device is functioning in reporting year.
- Hours = Hours in reporting year.

(4) For each digester, calculate the CH₄ leakage using Equation JJ-12 of this section.

$$\text{CH}_4\text{L} = \text{CH}_4\text{C} \times \left(\frac{1}{\text{CE}} - 1 \right) \quad (\text{Eq. JJ-12})$$

Where:

- CH₄L = Leakage at digesters (metric tons/yr).
- CH₄C = Annual quantity of CH₄ flow to digester combustion device, as calculated in Equation JJ-6 of this section (metric tons CH₄).
- CE = CH₄ collection efficiency of anaerobic digester, as specified in Table JJ-6 of this section (decimal).

(c) For each MMS component, estimate the annual N₂O emissions and sum for all MMS components to obtain total emissions from the manure management system for all animal types using Equation JJ-13 of this section.

$$\begin{aligned} &\text{Direct N}_2\text{O Emissions (metric tons/year)} = \\ &\sum_{\text{animal types}} [\sum_{\text{MMS}} \text{N}_{\text{ex AT}} \times \text{N}_{\text{ex, MMS}} \times (1 - \text{N}_{\text{ss}}) \times \text{EF}_{\text{MMS}} \times 365 \\ &\text{days/yr}] \\ &\quad \times 44\text{N}_2\text{O}/28 \text{ N}_2\text{O-N} \times 1 \text{ metric ton}/1000 \text{ kg} \quad (\text{Eq. JJ-13}) \end{aligned}$$

Where:

- N_{ex AT} = Daily total nitrogen excreted per animal type, calculated using Equation JJ-14 of this section (kg N/day).

- $N_{\text{ex,MMSC}}$ = Fraction of the total manure for each animal type that is managed in MMS component MMSC, assumed to be equivalent to the fraction of N_{ex} in each MMS component.
- N_{ss} = Nitrogen removal through solid separation; if solid separation occurs prior to the MMS component, use a default value from Table JJ-4 of this section; if no solid separation occurs, this value is set to 0.
- EF_{MMSC} = Emission factor for MMS component, as specified in Table JJ-7 of this section (kg N_2O -N/kg N).

$$N_{\text{ex AT}} = \text{Population}_{\text{AT}} \times \text{TAM}_{\text{AT}} \times N_{\text{AT}} / 1000 \text{ (Eq. JJ-14)}$$

Where:

- $N_{\text{ex AT}}$ = Total nitrogen excreted per animal type (kg/day).
- $\text{Population}_{\text{AT}}$ = Average annual animal population contributing manure to the manure management system by animal type(head) (see description in §98.363(a)(i) and (ii)).
- TAM_{AT} = Typical animal mass by animal type, using either default values in Table JJ-2 of this section or farm-specific data (kg/head).
- N_{AT} = Nitrogen excretion rate by animal type, using default values in Tables JJ-2 or JJ-3 of this section (kg N/day/1000 kg animal mass).

(d) Estimate the annual total facility emissions using Equation JJ-15 of this section.

$$\begin{aligned} \text{Total Emissions (metric tons CO}_2\text{e/yr)} = & \\ & [(\text{CH}_4 \text{ emissions}_{\text{MMS}} + \text{CH}_4 \text{ emissions}_{\text{AD}}) \times 21] + \\ & [\text{Direct N}_2\text{O emissions} \times 310] \text{ (Eq. JJ-15)} \end{aligned}$$

Where:

- $\text{CH}_4 \text{ emissions}_{\text{MMS}}$ = From Equation JJ-2 of this section.
- $\text{CH}_4 \text{ emissions}_{\text{AD}}$ = From Equation JJ-5 of this section.
- 21 = Global Warming Potential of CH_4 .
- Direct N_2O emissions = From Equation JJ-13 of this section.
- 310 = Global Warming Potential of N_2O .

§98.364 Monitoring and QA/QC requirements.

(a) Perform an annual animal inventory or review of facility records (for static populations) or population calculation (for growing populations) to determine the average annual animal population for each animal type (see description in §98.363(a) (i) and (ii) above).

(b) Perform an analysis on your operation to determine the fraction of total manure by weight for each animal type that is managed in each on-site manure management system component. If your system changes from previous reporting periods, you must reevaluate the fraction of total manure managed in each system component.

(c) The CH₄ concentration of gas from digesters must be determined using ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference see §98.7). All gas composition monitors shall be calibrated prior to the first reporting year for biogas methane and carbon dioxide content using ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference see §98.7) and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent, or whenever

the error in the midrange calibration check exceeds +/- 10 percent. All monitors shall be maintained as specified by the manufacturer.

(d) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer. All equipment (temperature and pressure monitors) shall be maintained as specified by the manufacturer.

(e) For digesters with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate to provide data for the GHG emissions calculations, using the applicable methods specified in paragraphs (e)(1) through (e)(6) of this section or as specified by the manufacturer.

(1) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(2) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(3) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(4) ASME MFC-7M-1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(5) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, see §98.7).

(6) ASME MFC-18M-2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, see §98.7).

(f) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of fuel flow meters and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(g) Each gas flow meter shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. Each gas flow meter must have a rated accuracy of +/-5 percent or lower and be capable of correcting for the temperature and pressure and, if the gas

composition monitor determines CH₄ concentration on a dry basis, moisture content.

§98.365 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraph (b) of this section.

(b) For missing gas flow rates or CH₄ content data, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

§98.366 Data reporting requirements.

(a) In addition to the information required by §98.3(c), each annual report must contain the following information:

- (1) List of manure management system components at the facility.
- (2) Fraction of manure from each animal type that is handled in each manure management system component.
- (3) Average annual animal population (for each animal type) for static populations or the results of Equation JJ-4 for growing populations.
- (4) Average number of days that growing animals are kept at the facility (for each animal type).
- (5) The number of animals produced annually for growing populations (for each animal type).
- (6) Typical animal mass (for each animal type).
- (7) Total facility emissions (results of Equation JJ-15).
- (8) CH₄ emissions from manure management system components listed in §98.360(b), except digesters (results of Equation JJ-2).
- (9) VS value used (for each animal type).
- (10) B₀ value used (for each animal type).
- (11) Methane conversion factor used for each MMS component.
- (12) Average ambient temperature used to select each methane conversion factor.
- (13) N₂O emissions (results of Equation JJ-13).

(14) N value used for each animal type.

(15) N₂O emission factor selected for each MMS component.

(b) Facilities with anaerobic digesters must also report:

(1) CH₄ emissions from anaerobic digesters (results of Equation JJ-5).

(2) CH₄ flow to the digester combustion device for each digester (results of Equation JJ-6, or value from fully integrated monitoring system as described in 98.363(b)).

(3) CH₄ destruction for each digester (results of Equation JJ-11).

(4) CH₄ leakage for each digester (results of Equation JJ-12).

(5) Total annual volumetric biogas flow for each digester (results of Equation JJ-7).

(6) Average annual CH₄ concentration for each digester (results of Equation JJ-8).

(7) Average annual temperature at which gas flow is measured for each digester (results of Equation JJ-9).

(8) Average annual gas flow pressure at which gas flow is measured for each digester (results of Equation JJ-10).

(9) Destruction efficiency used for each digester.

(10) Number of days per year that each digester was operating.

(11) Collection efficiency used for each digester.

§98.367 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration.

§98.368 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table JJ-1 of Subpart JJ—Animal Population Threshold Level Below which Facilities are not required to report Emissions under Subpart JJ^{1,2}

Animal Group		Average Annual Animal Population (Head) ³
Beef		29,300
Dairy		3,200
Swine		34,100
Poultry	Layers	723,600
	Broilers	38,160,000
	Turkeys	7,710,000

¹The threshold head populations in this table were calculated using the most conservative assumptions (high VS and N values, maximum ambient temperatures, and the application of an uncertainty factor) to ensure that facilities at or near the 25,000 metric ton CO₂e threshold level were not excluded from reporting.

²For facilities with more than one animal group present refer to §98.360 (2) to estimate the combined animal group factor (CAGF), which is used to determine if a facility may be required to report.

³For all animal groups except dairy, the average annual animal population represents the total number of animals present at the facility. For dairy facilities, the average annual animal population represents the number of mature dairy cows present at the facility (note that heifers and calves were included in the emission estimates for dairy facilities using the assumption that the average annual animal population of heifers and calves at dairy facilities are equal to 30 percent of the mature dairy cow average annual

animal population, therefore the average annual population for dairy facilities should not include heifers and calves, only dairy cows).

Table JJ-2 of Subpart JJ—Waste Characteristics Data

Animal Type	Typical Animal Mass (kg)	Volatile Solids Excretion Rate (kg VS/day/1000 kg animal mass)	Nitrogen Excretion Rate (kg N/day/1000 kg animal mass)	Maximum Methane Generation Potential, B ₀ (m ³ CH ₄ /kg VS added)
Dairy Cows	604	See Table JJ-3	See Table JJ-3	0.24
Dairy Heifers	476	See Table JJ-3	See Table JJ-3	0.17
Dairy calves	118	6.41	0.30	0.17
Feedlot Steers	420	See Table JJ-3	See Table JJ-3	0.33
Feedlot Heifers	420	See Table JJ-3	See Table JJ-3	0.33
Market Swine <60 lbs.	16	8.80	0.60	0.48
Market Swine 60-119 lbs.	41	5.40	0.42	0.48
Market Swine 120-179 lbs.	68	5.40	0.42	0.48
Market Swine >180 lbs.	91	5.40	0.42	0.48
Breeding Swine	198	2.60	0.24	0.48
Feedlot Sheep	25	9.20	0.42	0.36
Goats	64	9.50	0.45	0.17
Horses	450	10.00	0.30	0.33
Hens >= 1 yr	1.8	10.09	0.83	0.39
Pullets	1.8	10.09	0.62	0.39
Other Chickens	1.8	10.80	0.83	0.39
Broilers	0.9	15.00	1.10	0.36
Turkeys	6.8	9.70	0.74	0.36

Table JJ-3 of Subpart JJ- State-Specific Volatile Solids (VS) and Nitrogen (N) Excretion Rates for Cattle

State	Volatile Solids Excretion Rate (kg VS/day/1000 kg animal mass)				Nitrogen Excretion Rate (kg VS/day/1000 kg animal mass)			
	Dairy Cows	Dairy Heifers	Feedlot Steer	Feedlot Heifers	Dairy Cows	Dairy Heifers	Feedlot Steer	Feedlot Heifers
Alabama	8.40	8.35	4.27	4.74	0.50	0.46	0.36	0.38
Alaska	7.30	8.35	4.15	4.58	0.45	0.46	0.35	0.37
Arizona	10.37	8.35	3.91	4.27	0.58	0.46	0.33	0.34
Arkansas	7.59	8.35	3.98	4.35	0.46	0.46	0.33	0.35
California	10.02	8.35	3.96	4.33	0.56	0.46	0.33	0.34
Colorado	10.25	8.35	3.97	4.34	0.58	0.46	0.33	0.35
Connecticut	9.22	8.35	4.41	4.93	0.53	0.46	0.37	0.40
Delaware	8.63	8.35	4.19	4.64	0.51	0.46	0.35	0.37
Florida	8.90	8.35	4.15	4.58	0.52	0.46	0.35	0.37
Georgia	9.07	8.35	4.18	4.63	0.53	0.46	0.35	0.37
Hawaii	7.00	8.35	4.15	4.58	0.44	0.46	0.35	0.37
Idaho	10.11	8.35	4.03	4.42	0.57	0.46	0.34	0.35
Illinois	9.07	8.35	4.15	4.59	0.52	0.46	0.35	0.37

State	Volatile Solids Excretion Rate (kg VS/day/1000 kg animal mass)				Nitrogen Excretion Rate (kg VS/day/1000 kg animal mass)			
	Dairy Cows	Dairy Heifers	Feedlot Steer	Feedlot Heifers	Dairy Cows	Dairy Heifers	Feedlot Steer	Feedlot Heifers
Indiana	9.38	8.35	3.98	4.35	0.54	0.46	0.33	0.35
Iowa	9.46	8.35	3.93	4.28	0.54	0.46	0.33	0.34
Kansas	9.63	8.35	3.97	4.35	0.55	0.46	0.33	0.35
Kentucky	7.89	8.35	4.20	4.65	0.48	0.46	0.35	0.37
Louisiana	7.39	8.35	4.07	4.48	0.45	0.46	0.34	0.36
Maine	8.99	8.35	4.07	4.47	0.52	0.46	0.34	0.36
Maryland	9.02	8.35	4.05	4.45	0.52	0.46	0.34	0.35
Massachusetts	8.63	8.35	4.15	4.58	0.51	0.46	0.35	0.37
Michigan	10.05	8.35	4.00	4.38	0.57	0.46	0.34	0.35
Minnesota	9.17	8.35	3.89	4.24	0.53	0.46	0.33	0.34
Mississippi	8.19	8.35	4.14	4.57	0.49	0.46	0.35	0.37
Missouri	8.02	8.35	4.08	4.49	0.48	0.46	0.34	0.36
Montana	9.03	8.35	4.23	4.69	0.52	0.46	0.36	0.38
Nebraska	9.09	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Nevada	9.65	8.35	4.07	4.48	0.55	0.46	0.34	0.36
New Hampshire	9.44	8.35	3.94	4.30	0.54	0.46	0.33	0.34
New Jersey	8.51	8.35	3.98	4.36	0.50	0.46	0.33	0.35
New Mexico	10.34	8.35	3.88	4.22	0.58	0.46	0.32	0.33
New York	9.42	8.35	3.75	4.05	0.54	0.46	0.31	0.32
North Carolina	9.38	8.35	4.20	4.65	0.55	0.46	0.35	0.37
North Dakota	8.40	8.35	3.88	4.22	0.50	0.46	0.32	0.34
Ohio	9.01	8.35	3.96	4.33	0.52	0.46	0.33	0.34
Oklahoma	8.58	8.35	3.98	4.35	0.50	0.46	0.33	0.35
Oregon	9.40	8.35	4.06	4.46	0.54	0.46	0.34	0.36
Pennsylvania	9.26	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Rhode Island	8.94	8.35	4.36	4.87	0.52	0.46	0.37	0.39
South Carolina	9.05	8.35	4.15	4.58	0.53	0.46	0.35	0.37
South Dakota	9.45	8.35	4.01	4.39	0.54	0.46	0.34	0.35
Tennessee	8.60	8.35	4.48	5.02	0.51	0.46	0.38	0.40
Texas	9.51	8.35	3.95	4.32	0.54	0.46	0.33	0.34
Utah	9.70	8.35	3.88	4.22	0.55	0.46	0.32	0.34
Vermont	9.03	8.35	4.10	4.52	0.52	0.46	0.34	0.36
Virginia	9.02	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Washington	10.36	8.35	4.07	4.47	0.58	0.46	0.34	0.36
West Virginia	8.13	8.35	4.65	5.25	0.48	0.46	0.40	0.42
Wisconsin	9.34	8.35	3.95	4.31	0.54	0.46	0.33	0.34
Wyoming	9.29	8.35	4.17	4.61	0.53	0.46	0.35	0.37

Table JJ-4 of Subpart JJ-Volatile Solids and Nitrogen Removal through Solids Separation

Type of Solids Separation		Volatile Solids Removal (decimal)	Nitrogen Removal (decimal)
Gravity		0.60	0.60
Mechanical	Stationary Screen	0.20	0.10
	Vibrating Screen	0.15	0.15
	Screw Press	0.25	0.15
	Centrifuge	0.50	0.25

	Roller drum	0.25	0.15
	Belt press/screen	0.50	0.30

Table JJ-5 of Subpart JJ—Methane Conversion Factors

Manure Management System Component	MCFs by Average Annual Ambient Temperature (degrees C)																		
	Cool					Temperate										Warm			
	<10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	>28
Uncovered Anaerobic Lagoon	66%	68%	70%	71%	73%	74%	75%	76%	77%	77%	78%	78%	78%	79%	79%	79%	79%	80%	80%
Liquid/slurry (with crust cover)	10%	11%	13%	14%	15%	17%	18%	20%	22%	24%	26%	29%	31%	34%	37%	41%	44%	48%	50%
Liquid/slurry (w/o crust cover)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Storage pits <1 month	3.0%					3.0%										30.0%			
Storage pits >1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Solid manure storage	2.0%					4.0%										5.0%			
Dry lots (including feedlots)	1.0%					1.5%										2.0%			
High-rise houses for poultry production (without litter)	1.5%					1.5%										1.5%			
Poultry production with litter	1.5%					1.5%										1.5%			
Deep bedding systems for cattle and swine (<1 month)	3.0%					3.0%										30.0%			
Deep bedding systems for cattle and swine (>1 month)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Manure Composting - In Vessel	0.5%					0.5%										0.5%			
Manure Composting - Static Pile	0.5%					0.5%										0.5%			
Manure Composting- Extensive/ Passive	0.5%					1.0%										1.5%			
Manure Composting- Intensive	0.5%					1.0%										1.5%			
Aerobic Treatment	0.0%					0.0%										0.0%			

Table JJ-6 of Subpart JJ—Collection Efficiencies of Anaerobic Digesters

Anaerobic Digester Type	Cover Type	Methane Collection Efficiency
Covered anaerobic lagoon (biogas capture)	Bank to bank, impermeable	0.975
	Modular, impermeable	0.70
Complete mix, fixed film, or plug flow digester	Enclosed Vessel	0.99

Table JJ-7 of Subpart JJ—Nitrous Oxide Emission Factors (kg N₂O-N/kg Kjdl N)

Manure Management System Component	N ₂ O Emission Factor
Uncovered anaerobic lagoon	0
Liquid/Slurry (with crust cover)	0.005
Liquid/Slurry (without crust cover)	0
Storage pits	0.002
Digesters	0
Solid manure storage	0.005
Dry lots (including feedlots)	0.02
High-rise house for poultry (poultry without litter)	0.001
Poultry production with litter	0.001
Deep bedding for cattle and swine (active mix)	0.07
Deep bedding for cattle and swine (no mix)	0.01
Manure Composting (in vessel)	0.006
Manure Composting (intensive)	0.1
Manure Composting (passive)	0.01
Manure Composting (static)	0.006
Aerobic Treatment (forced aeration)	0.005
Aerobic Treatment (natural aeration)	0.01

Subpart KK [RESERVED]

Subpart LL—Suppliers of Coal-based Liquid Fuels

§98.380 Definition of the source category.

This source category consists of producers, importers, and exporters of products listed in Table MM-1 of subpart MM that are coal-based (coal-to-liquid products).

(a) A producer is the owner or operator of a coal-to-liquids facility. A coal-to-liquids facility is any facility engaged in converting coal into liquid products

using a process involving conversion of coal into gas and then into liquids (e.g., Fischer-Tropsch) or conversion of coal directly into liquids (i.e., direct liquefaction).

(b) An importer or exporter shall have the same meaning given in §98.6.

§98.381 Reporting threshold.

Any supplier of coal-to-liquid products who meets the requirements of §98.2(a)(4) must report GHG emissions.

§98.382 GHGs to report.

You must report the CO₂ emissions that would result from the complete combustion or oxidation of fossil-fuel products (besides coal or crude oil) that you produce, use as feedstock, import, or export during the calendar year. Additionally, producers must report CO₂ emissions that would result from the complete combustion or oxidation of any biomass co-processed with fossil fuel-based feedstocks.

§98.383 Calculating GHG emissions.

You must follow the calculation methodologies of §98.393 as if they applied to the appropriate coal-to-liquid product supplier (i.e., calculation methodologies for refiners apply to producers of coal-to-liquid products and calculation methodologies for importers and exporters of petroleum products apply to importers and exporters of coal-to-liquid products).

(a) In calculation methodologies in §98.393 for petroleum products or petroleum-based products, suppliers of coal-to-liquid products shall also include coal-to-liquid products.

(b) In calculation methodologies in §98.393 for non-crude feedstocks or non-crude petroleum feedstocks, producers of coal-to-liquid products shall also include coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

(c) In calculation methodologies in §98.393 for petroleum feedstocks, suppliers of coal-to-liquid products shall also include coal and coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

§98.384 Monitoring and QA/QC requirements.

You must follow the monitoring and QA/QC requirements in §98.394 as if they applied to the appropriate coal-to-liquid product supplier. Any monitoring and QA/QC requirement for petroleum products in §98.394 also applies to coal-to-liquid products.

§98.385 Procedures for estimating missing data.

You must follow the procedures for estimating missing data in §98.395 as if they applied to the appropriate coal-to-liquid product supplier. Any procedure for estimating

missing data for petroleum products in §98.395 also applies to coal-to-liquid products.

§98.386 Data reporting requirements.

In addition to the information required by §98.3(c), the following requirements apply:

(a) Producers shall report the following information for each coal-to-liquid facility:

(1) For each product listed in Table MM-1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in Table MM-1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each feedstock reported in paragraph (a)(2) that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the

volume reported in paragraph (a)(2) of this section that is fossil fuel-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(1) of this section.

(5) For each product (leaving the coal-to-liquid facility) listed in Table MM-1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(6) For each product (leaving the coal-to-liquid facility) listed in Table MM-1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is fossil fuel-based.

(8) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(5) of this section.

(9) For every feedstock reported in paragraph (a) (2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor.

(10) For every non-solid feedstock reported in paragraph (a) (2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every product reported in paragraph (a) (6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor.

(12) For every non-solid product reported in paragraph (a) (6) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(13) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a) (6) of this section, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used.

(14) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a) (6) of this section, report the total annual quantity in metric tons or barrels.

(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a) (3) of this section.

(16) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section, calculated according to §98.393(b) or (h).

(17) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each product (leaving the coal-to-liquid facility) reported in paragraph (a)(6) of this section, calculated according to §98.393(a) or (h).

(18) Annual CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with fossil fuel-based feedstocks reported in paragraph (a)(3) of this section, calculated according to §98.393(c).

(19) Annual CO₂ emissions that would result from the complete combustion or oxidation of all products, calculated according to §98.393(d).

(20) Annual quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

(b) In addition to the information required by §98.3(c), each importer shall report all of the following information at the corporate level:

(1) For each product listed in Table MM-1 of subpart MM of this part, report the annual quantity in metric tons

or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in Table MM-1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM-1 of subpart MM of this part.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is fossil fuel-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(1) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c)

(ii) The sampling standard method used.

- (iii) The carbon share test results in percent mass.
 - (iv) The standard method used to test carbon share.
 - (v) The calculated CO₂ emissions factor in metric tons.
- (6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:
- (i) The density test results in metric tons per barrel.
 - (ii) The standard method used to test density.
- (7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each imported product reported in paragraph (b)(2) of this section, calculated according to §98.393(a).
- (8) The total sum of CO₂ emissions that would result from the complete combustion or oxidation of all imported products, calculated according to §98.393(e).
- (c) In addition to the information required by §98.3(c), each exporter shall report all of the following information at the corporate level:
- (1) For each product listed in Table MM-1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or

other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in table MM-1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is fossil fuel-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(1) of this section.

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each exported product reported in paragraph (c)(2) of this section, calculated according to §98.393(a).

(8) Total sum of CO₂ emissions that would result from the complete combustion or oxidation of all exported products, calculated according to §98.393(e).

§98.387 Records that must be retained.

You must retain records according to the requirements in §98.397 as if they applied to the appropriate coal-to-liquid product supplier (e.g., retaining copies of all reports submitted to EPA under §98.386 and records to support information contained in those reports). Any records for petroleum products that are required to be

retained in §98.397 are also required for coal-to-liquid products.

§98.388 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart MM—Suppliers of Petroleum Products

§98.390 Definition of the source category.

This source category consists of petroleum refineries and importers and exporters of petroleum products and natural gas liquids as listed in Table MM-1 of this subpart.

(a) A petroleum refinery for the purpose of this subpart is any facility engaged in producing petroleum products through the distillation of crude oil.

(b) A refiner is the owner or operator of a petroleum refinery.

(c) Importer has the same meaning given in §98.6 and includes any entity that imports petroleum products or natural gas liquids as listed in Table MM-1 of this subpart. Any blender or refiner of refined or semi-refined petroleum products shall be considered an importer if it otherwise satisfies the aforementioned definition.

(d) Exporter has the same meaning given in §98.6 and includes any entity that exports petroleum products or

natural gas liquids as listed in Table MM-1 of this subpart. Any blender or refiner of refined or semi-refined petroleum products shall be considered an exporter if it otherwise satisfies the aforementioned definition.

§98.391 Reporting threshold.

Any supplier of petroleum products who meets the requirements of §98.2(a)(4) must report GHG emissions.

§98.392 GHGs to report.

Suppliers of petroleum products must report the CO₂ emissions that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid produced, used as feedstock, imported, or exported during the calendar year. Additionally, refiners must report CO₂ emissions that would result from the complete combustion or oxidation of any biomass co-processed with petroleum feedstocks.

§98.393 Calculating GHG emissions.

(a) Calculation for individual products produced, imported, or exported.

(1) Except as provided in paragraph (h) of this section, any refiner, importer, or exporter shall calculate CO₂ emissions from each individual petroleum product and natural gas liquid using Equation MM-1 of this section.

$$\text{CO}_{2i} = \text{Product}_i * \text{EF}_i \quad (\text{Eq. MM-1})$$

Where:

- CO_{2i} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).
- Product_i = Annual volume of product "i" produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate. For natural gas liquids, volumes shall reflect the individual components of the product as listed in Table MM-1 of this subpart.
- EF_i = Product-specific CO₂ emission factor (metric tons CO₂ per barrel).

(2) In the event that an individual petroleum product is produced as a solid rather than liquid any refiner, importer, or exporter shall calculate CO₂ emissions using Equation MM-1 of this section, where:

- CO_{2i} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each petroleum product "i" (metric tons).
- Product_i = Annual mass of product "i" produced, imported, or exported by the reporting party (metric tons). For refiners, this mass only includes products ex refinery gate.
- EF_i = Product-specific CO₂ emission factor (metric tons CO₂ per metric ton of product).

(b) Calculation for individual products that enter a refinery as a non-crude feedstock.

(1) Except as provided in paragraph (h) of this section, any refiner shall calculate CO₂ emissions from each non-crude feedstock using Equation MM-2 of this section.

$$\text{CO}_{2j} = \text{Feedstock}_j * \text{EF}_j \quad (\text{Eq. MM-2})$$

Where:

- CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).
- $Feedstock_j$ = Annual volume of a petroleum product or natural gas liquid "j" that enters the refinery to be further refined or otherwise used on site (barrels). For natural gas liquids, volumes shall reflect the individual components of the product as listed in table MM-1 of this subpart.
- EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

(2) In the event that a non-crude feedstock enters a refinery as a solid rather than liquid, the refiner shall calculate CO_2 emissions using Equation MM-2 of this section, where:

- CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).
- $Feedstock_j$ = Annual mass of a petroleum product "j" that enters the refinery to be further refined or otherwise used on site (metric tons).
- EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per metric ton of feedstock).

(c) Calculation for biomass co-processed with petroleum feedstocks.

(1) Refiners shall calculate CO_2 emissions from each type of biomass that enters a refinery and is co-processed with petroleum feedstocks using Equation MM-3 of this section.

$$CO_{2m} = Biomass_m * EF_m \quad (Eq. MM-3)$$

Where:

- CO_{2m} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).
- Biomass_m = Annual volume of a specific type of biomass that enters the refinery and is co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (barrels).
- EF_m = Biomass-specific CO₂ emission factor (metric tons CO₂ per barrel).

(2) In the event that biomass enters a refinery as a solid rather than liquid and is co-processed with petroleum feedstocks, the refiner shall calculate CO₂ emissions from each type of biomass using Equation MM-3 of this section.

Where:

- CO_{2m} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).
- Biomass_m = Total annual mass of a specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (metric tons).
- EF_m = Biomass-specific CO₂ emission factor (metric tons CO₂ per metric ton of biomass).

(d) Summary calculation for refinery products.

Refiners shall calculate annual CO₂ emissions from all products using Equation MM-4 of this section.

$$CO_{2r} = \sum (CO_{2i}) - \sum (CO_{2j}) - \sum (CO_{2m}) \quad (\text{Eq. MM-4})$$

Where:

- CO_{2r} = Annual CO₂ emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids (ex refinery gate) minus non-crude feedstocks and

any biomass to be co-processed with petroleum feedstocks.

- CO_{2i} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).
- CO_{2j} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).
- CO_{2m} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).

(e) Summary calculation for importer and exporter products. Importers and exporters shall calculate annual CO₂ emissions from all petroleum products and natural gas liquids imported or exported, respectively, using Equations MM-1 and MM-5 of this section.

$$CO_{2x} = \sum (CO_{2i}) \quad (\text{Eq. MM-5})$$

Where:

- CO_{2i} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).
- CO_{2x} = Annual CO₂ emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids.

(f) Emission factors for petroleum products and natural gas liquids. The emission factor (EF_{i,j}) for each petroleum product and natural gas liquid shall be determined using either of the calculation methods described in paragraphs (f) (1) or (f) (2) of this section.

The same calculation method must be used for the entire quantity of the product for the reporting year. For refiners, the quantity of a product that enters a refinery (i.e., a non-crude feedstock) is considered separate from the quantity of a product ex refinery gate.

(1) Calculation Method 1. For solid products, use the default carbon share factor (i.e., percent carbon by mass) in column B of Table MM-1 of this subpart for the appropriate product. For all other products, use the default CO₂ emission factor listed in column C of Table MM-1 of this subpart for the appropriate product.

(2) Calculation Method 2.

(i) For solid products, develop emission factors according to Equation MM-6 of this section using a value of 1 for density and direct measurements of carbon share according to methods set forth in §98.394(c). For all other products, develop emission factors according to Equation MM-6 of this section using direct measurements of density and carbon share according to methods set forth in §98.394(c).

$$EF_{i,j} = \text{Density} * \text{Carbon Share} * (44/12) \quad (\text{Eq. MM-6})$$

Where:

$EF_{i,j}$ = Emission factor of the petroleum product or natural gas liquid (metric tons CO₂ per barrel or per metric ton of product).

- Density = Density of the petroleum product or natural gas liquid (metric tons per barrel for non-solid products, 1 for solid products).
- Carbon share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).
- 44/12 = Conversion factor for carbon to carbon dioxide.

(ii) If you use a standard method that involves gas chromatography to determine the percent mass of each component in a product, calculate the product's carbon share using Equation MM-7 of this section.

$$\text{Carbon Share} = \sum (\% \text{Composition}_{i...n} * \% \text{Mass}_{i...n}) \quad (\text{Eq. MM-7})$$

Where:

- Carbon Share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid.
- $\% \text{Composition}_{i...n}$ = Percent of total mass that each molecular component in the petroleum product or natural gas liquid represents as determined by the procedures in the selected standard method.
- $\% \text{Mass}_{i...n}$ = Percent of total mass that carbon represents in each molecular component of the petroleum product or natural gas liquid.

(g) Emission factors for biomass co-processed with petroleum feedstocks. Refiners shall use the most appropriate default CO₂ emission factor (EF_m) for biomass in Table MM-2 of this subpart to calculate CO₂ emissions in paragraph (c) of this section.

(h) Special procedures for blended biomass-based fuels. In the event that some portion of a petroleum product is biomass-based and was not derived by co-processing biomass and petroleum feedstocks together (i.e., the petroleum product was produced by blending a petroleum-based product with a biomass-based fuel), the reporting party shall calculate emissions for the petroleum product according to one of the methods in paragraphs (h) (1) through (h) (4) of this section, as appropriate.

(1) A reporter using Calculation Methodology 1 to determine the emission factor of a petroleum product shall calculate the CO₂ emissions associated with that product using Equation MM-8 of this section in place of Equation MM-1 of this section.

$$\text{CO}_{2i} = \text{Product}_i * \text{EF}_i * \% \text{Vol}_i \quad (\text{Eq. MM-8})$$

Where:

CO_{2i} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each petroleum product "i" (metric tons).

Product_i = Annual volume of each petroleum product "i" produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Petroleum product-specific CO₂ emission factor (metric tons CO₂ per barrel) from Table MM-1 of this subpart.

%Vol_i = Percent volume of product "i" that is petroleum-based, including 2.5% of the volume of any ethanol product blended into a petroleum-based product to represent the

denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(2) A refinery using Calculation Methodology 1 of this subpart to determine the emission factor of a non-crude petroleum feedstock shall calculate the CO₂ emissions associated with that feedstock using Equation MM-9 of this section in place of Equation MM-2 of this section.

$$\text{CO}_{2j} = \text{Feedstock}_j * \text{EF}_i * \% \text{Vol}_j \quad (\text{Eq. MM-9})$$

Where:

CO_{2j} = Annual CO₂ emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

Feedstock_j = Annual volume of each petroleum product "j" that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels).

EF_j = Non-crude petroleum feedstock-specific CO₂ emission factor (metric tons CO₂ per barrel).

%Vol_j = Percent volume of feedstock "j" that is petroleum-based, including 2.5% of the volume of any ethanol product blended with the petroleum-based product to represent the denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(3) A reporter using Calculation Methodology 2 of this subpart to determine the emission factor of a petroleum product must calculate the CO₂ emissions associated with that product using Equation MM-10 of this section in place of Equation MM-1 of this section.

$$\text{CO}_{2i} = (\text{Product}_i * \text{EF}_i) - (\text{Product}_i * \text{EF}_m * \% \text{Vol}_m) \quad (\text{Eq. MM-10})$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each product "i" (metric tons).

$Product_i$ = Annual volume of each petroleum product "i" produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM-2 of this subpart that most closely represents the component of product "i" that is biomass-based.

$\%Vol_m$ = Percent volume of petroleum product "i" that is biomass-based, not including 2.5% of the volume of any ethanol product blended with the petroleum-based product, which represents the denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(4) A refiner using Calculation Methodology 2 of this subpart to determine the emission factor of a non-crude petroleum feedstock must calculate the CO_2 emissions associated with that feedstock using Equation MM-11 of this section in place of Equation MM-2 of this section.

$$CO_{2j} = (Feedstock_j * EF_j) - (Feedstock_i * EF_m * \%Vol_m) \text{ (Eq. MM-11)}$$

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

$Feedstock_j$ = Annual volume of each petroleum product "j" that enters the refinery to be further refined or otherwise used on site (barrels).

- EF_j = Feedstock-specific CO₂ emission factor (metric tons CO₂ per barrel).
- EF_m = Default CO₂ emission factor from Table MM-2 of this subpart that most closely represents the component of petroleum product "j" that is biomass-based.
- %Vol_m = Percent volume of non-crude feedstock "j" that is biomass-based, not including 2.5% of the volume of any ethanol product blended with the petroleum-based product, which represents the denaturant in that ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

§98.394 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) The quantity of petroleum products, natural gas liquids, biomass, and crude oil shall be determined as follows:

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. 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), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(iii) For products that are liquid at 60 degrees Fahrenheit and one standard atmosphere, all measurements of quantity shall be temperature-adjusted and pressure-adjusted to these conditions. For all other products, reporters shall use appropriate standard conditions specified in the standard method; if temperature and pressure conditions are not specified in the standard method or if a reporter uses an industry standard practice to determine quantity, the reporter shall use appropriate standard conditions according to established industry practices.

(2) All measurement equipment (including, but not limited to, flow meters and tank gauges) used for compliance with this subpart shall be appropriate for the standard method or industry standard practice followed under paragraph (a)(1)(i) or (a)(1)(ii) of this section.

(b) Equipment Calibration.

(1) All measurement equipment shall be calibrated prior to its first use for reporting under this subpart, using an appropriate standard method published by a

consensus based standards organization or according to the equipment manufacturer's directions.

(2) Measurement equipment shall be recalibrated at the minimum frequency specified by the standard method used or by the equipment manufacturer's directions.

(c) Procedures for Calculation Methodology 2 of this subpart.

(1) Reporting parties shall collect one sample of each petroleum product or natural gas liquid on any day of each calendar month of the reporting year in which the quantity of that product was measured in accordance with the requirements of this subpart. For example, if a given product was measured as entering the refinery continuously throughout the reporting year, twelve samples of that product shall be collected over the reporting year, one on any day of each calendar month of that year. If a given product was only measured from April 15 through June 10 of the reporting year, a refiner would collect three samples during that year, one during each of the calendar months of April, May and June on a day when the product was measured as either entering or exiting the refinery. Each sample shall be collected using an appropriate standard method published by a consensus-based standards organization.

(2) Mixing and handling of samples shall be performed using an appropriate standard method published by a consensus-based standards organization.

(3) Density measurement.

(i) For all products that are not solid, reporters shall test for density using an appropriate standard method published by a consensus-based standards organization.

(ii) The density value for a given petroleum product shall be generated by either making a physical composite of all of the samples collected for the reporting year and testing that single sample or by measuring the individual samples throughout the year and defining the representative density value for the sample set by numerical means, i.e., a mathematical composite. If a physical composite is chosen as the option to obtain the density value, the reporter shall submit each of the individual samples collected during the reporting year to the laboratory responsible for generating the composite sample.

(iii) For physical composites, the reporter shall handle the individual samples and the laboratory shall mix them in accordance with an appropriate standard method published by a consensus-based standards organization.

(iv) All measurements of density shall be temperature-adjusted and pressure-adjusted to the

conditions assumed for determining the quantities of the product reported under this subpart.

(4) Carbon share measurement.

(i) Reporters shall test for carbon share using an appropriate standard method published by a consensus-based standards organization.

(ii) If a standard method that involves gas chromatography is used to determine the percent mass of each component in a product, the molecular formula for each component shall be obtained from the information provided in the standard method and the atomic mass of each element in a given molecular component shall be obtained from the periodic table of the elements.

(iii) The carbon share value for a given petroleum product shall be generated by either making a physical composite of all of the samples collected for the reporting year and testing that single sample or by measuring the individual samples throughout the year and defining the representative carbon share value for the sample set by numerical means, i.e., a mathematical composite. If a physical composite is chosen as the option to obtain the carbon share value, the reporter shall submit each of the individual samples collected during the reporting year to

the laboratory responsible for generating the composite sample.

(iv) For physical composites, the reporter shall handle the individual samples and the laboratory shall mix them in accordance with an appropriate standard method published by a consensus-based standards organization.

(d) Measurement of API gravity and sulfur content of crude oil.

(1) Samples of each batch of crude oil shall be taken according to an appropriate standard method published by a consensus-based standards organization.

(2) Samples shall be handled according to an appropriate standard method published by a consensus-based standards organization.

(3) API gravity shall be measured using an appropriate standard method published by a consensus-based standards organization.

(4) Sulfur content shall be measured using an appropriate standard method published by a consensus-based standards organization.

(5) All measurements shall be temperature-adjusted and pressure-adjusted to the conditions assumed for determining the quantities of crude oil reported under this subpart.

§98.395 Procedures for estimating missing data.

(a) Determination of quantity. Whenever the quality assurance procedures in §98.394(a) cannot be followed to measure the quantity of one or more petroleum products, natural gas liquids, types of biomass, feedstocks, or crude oil batches during any period (e.g., if a meter malfunctions), the following missing data procedures shall be used:

(1) For quantities of a product that are purchased or sold, a period of missing data shall be substituted using a reporter's established procedures for billing purposes in that period as agreed to by the party selling or purchasing the product.

(2) For quantities of a product that are not purchased or sold but of which the custody is transferred, a period of missing data shall be substituted using a reporter's established procedures for tracking purposes in that period as agreed to by the party involved in custody transfer of the product.

(b) Determination of emission factor. Whenever any of the procedures in §98.394(c) cannot be followed to develop an emission factor for any reason, Calculation Methodology 1 of this subpart must be used in place of

Calculation Methodology 2 of this subpart for the entire reporting year.

(c) Determination of API gravity and sulfur content of crude oil. For missing data on sulfur content or API gravity, the substitute data value shall be the arithmetic average of the quality-assured values of API gravity or sulfur content in the batch preceding and the batch immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured values for API gravity and sulfur content obtained from the batch after the missing data period.

§98.396 Data reporting requirements.

In addition to the information required by §98.3(c), the following requirements apply:

(a) Refiners shall report the following information for each facility:

(1) For each petroleum product or natural gas liquid listed in table MM-1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each petroleum product or natural gas liquid listed in Table MM-1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each feedstock reported in paragraph (a) (2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a) (2) of this section that is petroleum-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a) (1) of this section.

(5) For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(6) For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels. For

natural gas liquids, quantity shall reflect the individual components of the product.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is petroleum-based.

(8) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(5) of this section.

(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

- (i) The number of samples collected according to §98.394(c)
- (ii) The sampling standard method used.
- (iii) The carbon share test results in percentmass.
- (iv) The standard method used to test carbon share.
- (v) The calculated CO₂ emissions factor in metric tons.

(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every petroleum product and natural gas liquid reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percentmass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(12) For every non-solid petroleum product and natural gas liquid reported in paragraph (a)(6) for which Calculation Method 2 was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(13) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks

to produce a petroleum product reported in paragraph (a) (6) of this section, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used.

(14) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in paragraph (a) (6) of this section, report the annual quantity in metric tons or barrels.

(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a) (13) of this section.

(16) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid (ex refinery gate) reported in paragraph (a) (6) of this section, calculated according to §98.393(a) or (h).

(17) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a) (2) of this section, calculated according to §98.393(b) or (h).

(18) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum

feedstocks reported in paragraph (a) (13) of this section, calculated according to §98.393(c).

(19) The sum of CO₂ emissions that would result from the complete combustion or oxidation of all products, calculated according to §98.393(d).

(20) All of the following information for all crude oil feedstocks used at the refinery:

(i) Batch volume in barrels.

(ii) API gravity of the batch at the point of entry at the refinery.

(iii) Sulfur content of the batch at the point of entry at the refinery.

(iv) Country of origin of the batch, if known.

(21) The quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

(b) In addition to the information required by §98.3(c), each importer shall report all of the following information at the corporate level:

(1) For each petroleum product and natural gas liquid listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each petroleum product and natural gas liquid listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM-1 of this subpart.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is petroleum-based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(1) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c)

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each imported petroleum product and natural gas liquid reported in paragraph (b)(2) of this section, calculated according to §98.393(a).

(8) The sum of CO₂ emissions that would result from the complete combustion oxidation of all imported products, calculated according to §98.393(e).

(c) In addition to the information required by §98.3(c), each exporter shall report all of the following information at the corporate level:

(1) For each petroleum product and natural gas liquid listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each petroleum product and natural gas liquid listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is petroleum based.

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(1) of this section.

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percentmass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of for each exported petroleum product and natural gas liquid reported in paragraph (c)(2) of this section, calculated according to §98.393(a).

(8) The sum of CO₂ emissions that would result from the complete combustion or oxidation of all exported products, calculated according to §98.393(e).

§98.397 Records that must be retained.

(a) All reporters shall retain copies of all reports submitted to EPA under §98.396. In addition, all reporters shall maintain sufficient records to support information contained in those reports, including but not limited to information on the characteristics of their feedstocks and products.

(b) Reporters shall maintain records to support quantities that are reported under this subpart, including

records documenting any estimations of missing data and the number of calendar days in the reporting year for which substitute data procedures were followed. For all quantities of petroleum products, natural gas liquids, biomass, and feedstocks, reporters shall maintain metering, gauging, and other records normally maintained in the course of business to document product and feedstock flows including the date of initial calibration and the frequency of recalibration for the measurement equipment used

(c) Reporters shall retain laboratory reports, calculations and worksheets used to estimate the CO₂ emissions of the quantities of petroleum products, natural gas liquids, biomass, and feedstocks reported under this subpart.

(d) Reporters shall maintain laboratory reports, calculations and worksheets used in the measurement of density and carbon share for any petroleum product or natural gas liquid for which CO₂ emissions were calculated using Calculation Methodology 2.

(e) Reporters shall maintain laboratory reports, calculations and worksheets used in the measurement of API gravity and sulfur content for every crude oil batch reported under this subpart.

(f) Estimates of missing data shall be documented and records maintained showing the calculations.

(g) Reporters described in this subpart shall also retain all records described in §98.3(g).

§98.398 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table MM-1 of Subpart MM—Default Factors for Petroleum Products and Natural Gas Liquids^{1,2}

Products	<u>Column A:</u> Density (metric tons/bbl)	<u>Column B:</u> Carbon Share (% of mass)	<u>Column C:</u> Emission Factor (metric tons CO₂/bbl)
Finished Motor Gasoline			
Conventional - Summer			
Regular	0.1181	86.66	0.3753
Midgrade	0.1183	86.63	0.3758
Premium	0.1185	86.61	0.3763
Conventional - Winter			
Regular	0.1155	86.50	0.3663
Midgrade	0.1161	86.55	0.3684
Premium	0.1167	86.59	0.3705
Reformulated - Summer			
Regular	0.1167	86.13	0.3686
Midgrade	0.1165	86.07	0.3677
Premium	0.1164	86.00	0.3670
Reformulated - Winter			
Regular	0.1165	86.05	0.3676
Midgrade	0.1165	86.06	0.3676
Premium	0.1166	86.06	0.3679
Gasoline-Other	0.1185	86.61	0.3763
Blendstocks			
CBOB-Summer			
Regular	0.1181	86.66	0.3753
Midgrade	0.1183	86.63	0.3758
Premium	0.1185	86.61	0.3763
CBOB-Winter			
Regular	0.1155	86.50	0.3663

Products	Column A: Density (metric tons/bbl)	Column B: Carbon Share (% of mass)	Column C: Emission Factor (metric tons CO₂/bbl)
Midgrade	0.1161	86.55	0.3684
Premium	0.1167	86.59	0.3705
RBOB-Summer			
Regular	0.1167	86.13	0.3686
Midgrade	0.1165	86.07	0.3677
Premium	0.1164	86.00	0.3670
RBOB-Winter			
Regular	0.1165	86.05	0.3676
Midgrade	0.1165	86.06	0.3676
Premium	0.1166	86.06	0.3679
Blendstocks-Other	0.1185	86.61	0.3763
Oxygenates			
Methanol	0.1268	37.48	0.1743
GTBA	0.1257	64.82	0.2988
MTBE	0.1181	68.13	0.2950
ETBE	0.1182	70.53	0.3057
TAME	0.1229	70.53	0.3178
DIPE	0.1156	70.53	0.2990
Distillate Fuel Oil			
Distillate No. 1			
Ultra Low Sulfur	0.1346	86.40	0.4264
Low Sulfur	0.1346	86.40	0.4264
High Sulfur	0.1346	86.40	0.4264
Distillate No. 2			
Ultra Low Sulfur	0.1342	87.30	0.4296
Low Sulfur	0.1342	87.30	0.4296
High Sulfur	0.1342	87.30	0.4296
Distillate Fuel Oil No. 4	0.1452	86.47	0.4604
Residual Fuel Oil No. 5 (Navy Special)	0.1365	85.67	0.4288
Residual Fuel Oil No. 6 (a.k.a. Bunker C)	0.1528	84.67	0.4744
Kerosene-Type Jet Fuel	0.1294	86.30	0.4095
Kerosene	0.1346	86.40	0.4264
Diesel-Other	0.1452	86.47	0.4604
Petrochemical Feedstocks			
Naphthas (< 401°F)	0.1158	84.11	0.3571
Other Oils (> 401°F)	0.1390	87.30	0.4450
Unfinished Oils			
Heavy Gas Oils	0.1476	85.80	0.4643

Products	Column A: Density (metric tons/bbl)	Column B: Carbon Share (% of mass)	Column C: Emission Factor (metric tons CO₂/bbl)
Residuum	0.1622	85.70	0.5097
Other Petroleum Products and Natural Gas Liquids			
Aviation Gasoline	0.1120	85.00	0.3490
Special Naphthas	0.1222	84.76	0.3798
Lubricants	0.1428	85.80	0.4492
Waxes	0.1285	85.30	0.4019
Petroleum Coke	0.1818	92.28	0.6151
Asphalt and Road Oil	0.1634	83.47	0.5001
Still Gas	0.1405	77.70	0.4003
Ethane	0.0866	79.89	0.2537
Ethylene	0.0903	85.63	0.2835
Propane	0.0784	81.71	0.2349
Propylene	0.0803	85.63	0.2521
Butane	0.0911	82.66	0.2761
Butylene	0.0935	85.63	0.2936
Isobutane	0.0876	82.66	0.2655
Isobutylene	0.0936	85.63	0.2939
Pentanes Plus	0.1055	83.63	0.3235
Miscellaneous Products	0.1380	85.49	0.4326

1. In the case of products blended with some portion of biomass-based fuel, the carbon share in Table MM-1 of this subpart represents only the petroleum-based components.

2. Products that are derived entirely from biomass should not be reported, but products that were derived from both biomass and a petroleum product (i.e., co-processed) should be reported as the petroleum product that it most closely represents.

Table MM-2 of Subpart MM-Default Factors for Biomass-Based Fuels and Biomass

	Column A: Density (metric tons/bbl)	Column B: Carbon Share (% of mass)	Column C: Emission Factor (metric tons CO₂/bbl)
Biomass-Based Fuel and Biomass			
Ethanol (100%)	0.1267	52.14	0.2422
Biodiesel (100%, methyl ester)	0.1396	77.30	0.3957
Rendered Animal Fat	0.1333	76.19	0.3724
Vegetable Oil	0.1460	76.77	0.4110

Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids§98.400 Definition of the source category.

This supplier category consists of natural gas liquids fractionators and local natural gas distribution companies.

(a) Natural gas liquids fractionators are installations that fractionate natural gas liquids (NGLs) into their constituent liquid products (ethane, propane, normal butane, isobutane or pentanes plus) for supply to downstream facilities.

(b) Local Distribution Companies (LDCs) are companies that own or operate distribution pipelines, not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems.

(c) This supply category does not consist of the following facilities:

- (1) Field gathering and boosting stations.
- (2) Natural gas processing plants that separate NGLs from natural gas and produce bulk or y-grade NGLs but do not fractionate these NGLs into their constituent products.

(3) Facilities that meet the definition of refineries and report under subpart MM of this part.

(4) Facilities that meet the definition of petrochemical plants and report under subpart X of this part.

§98.401 Reporting threshold.

Any supplier of natural gas and natural gas liquids that meets the requirements of §98.2(a)(4) must report GHG emissions.

§98.402 GHGs to report.

(a) NGL fractionators must report the CO₂ emissions that would result from the complete combustion or oxidation of the annual quantity of ethane, propane, normal butane, isobutane, and pentanes plus that is produced and sold or delivered to others.

(b) LDCs must report the CO₂ emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end-users on their distribution systems.

§98.403 Calculating GHG emissions.

(a) LDCs and fractionators shall, for each individual product reported under this part, calculate the estimated CO₂ emissions that would result from the complete combustion

or oxidation of the products supplied using either of Calculation Methodology 1 or 2 of this subpart:

(1) Calculation Methodology 1. NGL fractionators shall estimate CO₂ emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN-1 of this section. LDCs shall estimate CO₂ emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN-1. For each product, use the default value for higher heating value and CO₂ emission factor in Table NN-1 of this subpart. Alternatively, for each product, a reporter-specific higher heating value and CO₂ emission factor may be used, in place of one or both defaults provided they are developed using methods outlined in §98.404. For each product, you must use the same volume unit throughout the equation.

$$CO_{2i} = 1 \times 10^{-3} * \sum Fuel_h * HHV_h * EF_h \quad (\text{Eq. NN-1})$$

Where:

CO_{2i} = Annual CO₂ mass emissions that would result from the combustion or oxidation of each product "h" for redelivery to all recipients (metric tons).

Fuel = Total annual volume of product "h" supplied (volume per year, in Mscf for natural gas and bbl for NGLs).

HHV = Higher heating value of product "h" supplied (MMBtu/ Mscf or MMBtu/bbl).

EF_h = CO₂ emission factor of product "h" (kg CO₂/MMBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons (MT/kg).

(2) Calculation Methodology 2. NGL fractionators shall estimate CO₂ emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN-2 of this section. LDCs shall estimate CO₂ emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN-2. For each product, use the default CO₂ emission factor found in Table NN-2 of this subpart. Alternatively, for each product, a reporter-specific CO₂ emission factor may be used in place of the default factor, provided it is developed using methods outlined in §98.404. For each product, you must use the same volume unit throughout the equation.

$$CO_{2i} = \sum_h Fuel_h * EF_h \quad (\text{Eq. NN-2})$$

Where:

CO_{2i} = Annual CO₂ mass emissions that would result from the combustion or oxidation of each product "h" (metric tons)

Fuel = Total annual volume of product "h" supplied (bbl or Mscf per year)

EF_h = CO₂ emission factor of product "h" (MT CO₂/bbl, or MT CO₂/Mscf)

(b) Each LDC shall follow the procedures below.

(1) For natural gas that is received for redelivery to downstream gas transmission pipelines and other local distribution companies, use eEquation NN-3 of this section and the default values for the CO₂ emission factors found in Table NN-2 of this subpart. Alternatively, reporter-specific CO₂ emission factors may be used, provided they are developed using methods outlined in §98.404.

$$\text{CO}_{2j} = \text{Fuel} * \text{EF} \quad (\text{Eq. NN-3})$$

Where:

CO_{2j} = Annual CO₂ mass emissions that would result from the combustion or oxidation of natural gas for redelivery to transmission pipelines or other LDCs (metric tons).

Fuel = Total annual volume of natural gas supplied (Mscf per year).

EF = Fuel-specific CO₂ emission factor (MT CO₂/Mscf).

(2) For natural gas delivered to each meter registering a supply equal to or greater than 460,000 Mscf per year, use Equation NN-4 of this section and the default values for the CO₂ emission factors found in Table NN-2 of this subpart.

Alternatively, reporter-specific CO₂ emission factors may be used, provided they are developed using methods outlined in §98.404.

$$\text{CO}_{2k} = \text{Fuel} * \text{EF} \quad (\text{Eq. NN-4})$$

Where:

CO_{2k} = Annual CO₂ mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year (metric tons).

Fuel = Total annual volume of natural gas supplied (Mscf per year).

EF = Fuel-specific CO₂ emission factor (MT CO₂/Mscf).

(3) For natural gas received by the LDC at the city gate that is injected into on-system storage, and/or liquefied and stored, use Equation NN-5 of this section and the default value for the CO₂ emission factors found in Table NN-2 of this subpart. Alternatively, a reporter-specific CO₂ emission factor may be used, provided it is developed using methods outlined in §98.404.

$$CO_{21} = [Fuel_1 - Fuel_2] * EF \quad (\text{Eq. NN-5})$$

Where:

CO₂₁ = Annual CO₂ mass emissions that would result from the combustion or oxidation of the net natural gas that is liquefied and/or stored and not used for deliveries by the LDC within the reported year (metric tons).

Fuel₁ = Total annual volume of natural gas received by the LDC at the city gate and stored on-system or liquefied and stored in the reporting year (Mscf per year).

Fuel₂ = Total annual volume of natural gas that is used for deliveries in the reporting year that was not otherwise accounted for in Equation NN-1 or NN-2 of this section (Mscf per year). This primarily includes natural gas previously stored on-system or liquefied and stored that is removed from storage and used for deliveries to customers or other LDCs by the LDC within the reporting year. This also includes natural gas that bypassed the city gate and was delivered directly to LDC

systems from producers or natural gas processing plants from local production.

EF = Fuel-specific CO₂ emission factor (MT CO₂/Mscf).

(4) Calculate the total CO₂ emissions that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users using Equation NN-6 of this section.

$$CO_2 = \sum CO_{2i} - \sum CO_{2j} - \sum CO_{2k} - \sum CO_{2l} \quad (\text{Eq. NN-6})$$

Where:

- CO₂ = Annual CO₂ mass emissions that would result from the combustion or oxidation of natural gas delivered to LDC customers not covered in paragraph (b)(2) of this section (metric tons).
- CO_{2i} = Annual CO₂ mass emissions that would result from the combustion or oxidation of natural gas received at the city gate as calculated in paragraph (a)(1) or (a)(2) of this section (metric tons).
- CO_{2j} = Annual CO₂ mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).
- CO_{2k} = Annual CO₂ mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year as calculated in paragraph (b)(2) of this section (metric tons).
- CO_{2l} = Annual CO₂ mass emissions that would result from the combustion or oxidation of natural gas received by the LDC and liquefied and/or stored but not used for deliveries within the reported year as calculated in paragraph (b)(3) of this section (metric tons).

(c) Each NGL fractionator shall follow the following procedures.

(1) For fractionated NGLs received by the reporter from other NGL fractionators, you shall use Equation NN-7 of this section and the default values for the CO₂ emission factors found in Table NN-2 of this subpart.

Alternatively, reporter-specific CO₂ emission factors may be used, provided they are developed using methods outlined in §98.404.

$$CO_{2m} = \sum_g Fuel_g * EF_g \quad (\text{Eq. NN-7})$$

Where:

CO_{2m} = Annual CO₂ mass emissions that would result from the combustion or oxidation of each fractionated NGL product "g" received from other fractionators (metric tons).

Fuel_g = Total annual volume of each NGL product "g" received (bbls).

EF = Fuel-specific CO₂ emission factor (MT CO₂/bbl).

(2) Calculate the total CO₂ equivalent emissions that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received by other fractionators using Equation NN-8 of this section.

$$CO_2 = \sum CO_{2i} - \sum CO_{2j} \quad (\text{Eq. NN-8})$$

Where:

CO₂ = Annual CO₂ mass emissions that would result from the combustion or oxidation of fractionated NGLs

delivered to customers or on behalf of customers (metric tons).

CO_{2i} = Annual CO₂ mass emissions that would result from the combustion or oxidation of fractionated NGLs delivered to all customers as calculated in paragraph (a) (1) or (a) (2) of this section (metric tons).

CO_{2m} = Annual CO₂ mass emissions that would result from the combustion or oxidation of fractionated NGLs received from other fractionators and calculated in paragraph (c) (1) of this section (metric tons).

§98.404 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) NGL fractionators and LDCs shall determine the quantity of NGLs and natural gas using methods in common use in the industry for billing purposes as audited under existing Sarbanes Oxley regulationn.

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. 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), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(2) NGL fractionators and LDCs shall base the minimum frequency of the product quantity measurements, to be summed to the annual quantity reported, on the reporter's standard practices for commercial operations.

(i) For NGL fractionators the minimum frequency of measurements shall be the measurements taken at custody transfers summed to the annual reportable volume.

(ii) For natural gas the minimum frequency of measurement shall be based on the LDC's standard measurement schedules used for billing purposes and summed to the annual reportable volume.

(3) NGL fractionators shall use measurement for NGLs at custody transfer meters or at such meters that are used to determine the NGL product slate delivered from the fractionation facility.

(4) If a NGL fractionator supplies a product not listed in Table NN-1 of this subpart that is a mixture or blend of two or more products listed in Tables NN-1 and NN-2 of this subpart, the NGL fractionator shall report the quantities of the constituents of the mixtures or blends separately.

(5) For an LDC using Equation NN-1 or NN-2 of this subpart, the point(s) of measurement for the natural gas volume supplied shall be the LDC city gate meter(s).

(i) If the LDC makes its own quantity measurements according to established business practices, its own measurements shall be used.

(ii) If the LDC does not make its own quantity measurements according to established business practices, it shall use its delivering pipeline invoiced measurements for natural gas deliveries to the LDC city gate, used in determining daily system sendout.

(6) An LDC using Equation NN-3 of this subpart shall measure natural gas at the custody transfer meters.

(7) An LDC using Equation NN-4 of this subpart shall measure natural gas at the customer meters. The reporter shall consider the volume delivered through a single particular meter at a single particular location as the volume delivered to an individual end-user.

(8) An LDC using Equation NN-5 of this subpart shall measure natural gas as follows:

(i) Fuel₁ shall be measured at the on-system storage injection meters and/or at the meters measuring natural gas to be liquefied.

(ii) Fuel₂ shall be measured at the meters used for measuring on-system storage withdrawals and/or LNG vaporization injection. If Fuel₂ is from a source other than storage, the appropriate meter shall be used to measure the quantity.

(9) An LDC shall measure all natural gas under the following standard industry temperature and pressure conditions: cubic foot of gas at a temperature of 60 degrees Fahrenheit and at an absolute pressure of fourteen and seventy-three hundredths (14.73) pounds per square inch.

(b) Determination of higher heating values (HHV).

(1) When a reporter uses the default HHV provided in this section to calculate Equation NN-1 of this subpart, the appropriate value shall be taken from Table NN-1 of this subpart.

(2) When a reporter uses a reporter-specific HHV to calculate Equation NN-1 of this subpart, an appropriate standard test published by a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(i) If an LDC makes its own HHV measurements according to established business practices, then its own measurements shall be used.

(ii) If an LDC does not make its own measurements according to established business practices, it shall use its delivering pipeline measurements.

(c) Determination of emission factor (EF).

(1) When a reporter used the default EF provided in this section to calculate Equation NN-1 of this subpart, the appropriate value shall be taken from Table NN-1 of this subpart.

(2) When a reporter used the default EF provided in this section to calculate Equation NN-2, NN-3, NN-4, NN-5, or NN-7 of this subpart, the appropriate value shall be taken from Table NN-2 of this subpart.

(3) When a reporter uses a reporter-specific EF, the reporter shall use an appropriate standard method published by a consensus-based standards organization to conduct compositional analysis necessary to determine reporter-specific CO₂ emission factors. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(d) Equipment Calibration.

(1) Equipment used to measure quantities in Equations NN-1, NN-2, and NN-5 of this subpart shall be calibrated prior to its first use for reporting under this subpart, using a suitable standard method published by a consensus based standards organization or according to the equipment manufacturer's directions.

(2) Equipment used to measure quantities in Equations NN-1, NN-2, and NN-5 of this subpart shall be recalibrated at the frequency specified by the standard method used or by the manufacturer's directions.

§98.405 Procedures for estimating missing data.

(a) Whenever a quality-assured value of the quantity of natural gas liquids or natural gas supplied during any period is unavailable (e.g., if a flow meter malfunctions), a substitute data value for the missing quantity measurement must be used in the calculations according to paragraphs (b) and (c) of this section.

(b) Determination of quantity.

(1) NGL fractionators shall substitute meter records provided by pipeline(s) for all pipeline receipts of NGLs; by manifests for deliveries made to trucks or rail cars; or metered quantities accepted by the entities purchasing the output from the fractionator whether by pipeline or by truck or rail car. In cases where the metered data from

the receiving pipeline(s) or purchasing entities are not available, fractionators may substitute estimates based on contract quantities required to be delivered under purchase or delivery contracts with other parties.

(2) LDCs shall either substitute their delivering pipeline metered deliveries at the city gate or substitute nominations and scheduled delivery quantities for the period when metered values of actual deliveries are not available.

(c) Determination of HHV and EF.

(1) Whenever an LDC that makes its own HHV measurements according to established business practices cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in §98.404, during any period for any reason, the reporter shall use either its delivering pipeline measurements or the default HHV provided in Table NN-1 of this part for that period.

(2) Whenever an LDC that does not make its own HHV measurements according to established business practices or an NGL fractionator cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in §98.404, during any period for any reason, the

reporter shall use the default HHV provided in Table NN-1 of this part for that period.

(3) Whenever a NGL fractionator cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in §98.404, during any period for any reason, the NGL fractionator shall use the default HHV provided in Table NN-1 of this part for that period.

(4) Whenever a reporter cannot follow the quality assurance procedures for developing a reporter-specific EF, as specified in §98.404, during any period for any reason, the reporter shall use the default EF provided in §98.408 for that period.

§98.406 Data reporting requirements.

(a) In addition to the information required by §98.3(c), the annual report for each NGL fractionator covered by this rule shall contain the following information.

(1) Annual quantity (in barrels) of each NGL product supplied to downstream facilities in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(2) Annual quantity (in barrels) of each NGL product received from other NGL fractionators in the following

product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(3) Annual volumes in Mscf of natural gas received for processing.

(4) Annual quantity (in barrels) of y-grade, bulk NGLs received from others for fractionation.

(5) Annual quantity (in barrels) of propane that the NGL fractionator odorizes at the facility and delivers to others.

(6) Annual CO₂ emissions (metric tons) that would result from the complete combustion or oxidation of the quantities in paragraphs (b) (1) and (b) (2) of this section, calculated in accordance with §98.403(a) and (c) (1).

(7) Annual CO₂ mass emissions (metric tons) that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received by other fractionators, calculated in accordance with §98.403(c) (2).

(8) The specific industry standard used to measure each quantity reported in paragraph (a) (1) of this section.

(9) If the LNG fractionator developed reporter-specific EFs or HHVs, report the following:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404 (b) (2) and (c) (3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(b) In addition to the information required by §98.3(c), the annual report for each LDC shall contain the following information.

(1) Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC.

(2) Annual volume in Mscf of natural gas placed into storage.

(3) Annual volume in Mscf of vaporized liquefied natural gas (LNG) produced at on-system vaporization facilities for delivery on the distribution system that is not accounted for in paragraph (b) (1) of this section.

(4) Annual volume in Mscf of natural gas withdrawn from on-system storage (that is not delivered to the city gate) for delivery on the distribution system.

(5) Annual volume in Mscf of natural gas delivered directly to LDC systems from producers or natural gas processing plants from local production.

(6) Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.

(7) Annual volume in Mscf of natural gas delivered by LDC to each meter registering supply equal to or greater than 460,000 Mscf during the calendar year.

(8) The total annual CO₂ mass emissions (metric tons) associated with the volumes in paragraphs (b) (1) through (b) (7) of this section, calculated in accordance with §98.403(a) and (b) (1) through (b) (3).

(9) Annual CO₂ emissions (metric tons) that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users registering less than 460,000 Mscf, calculated in accordance with §98.403(b) (4).

(10) The specific industry standard used to develop the volume reported in paragraph (b) (1) of this section.

(11) If the LDC developed reporter-specific EFs or HHVs, report the following:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404 (b) (2) and (c) (3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(12) The customer name, address, and meter number of each meter reading used to report in paragraph (b) (7) of this section.

(i) If known, report the EIA identification number of each LDC customer.

(13) The annual volume in Mscf of natural gas delivered by the local distribution company to each of the following end-use categories. For definitions of these categories, refer to EIA Form 176 (Annual Report of Natural Gas and Supplemental Gas Supply & Disposition) and Instructions.

(i) Residential consumers.

(ii) Commercial consumers.

(iii) Industrial consumers.

(iv) Electricity generating facilities.

(c) Each reporter shall report the number of days in the reporting year for which substitute data procedures were used for the following purpose:

(i) To measure quantity.

(ii) To develop HHV(s).

(iii) To develop EF(s).

§98.407 Records that must be retained.

In addition to the information required by §98.3(g), each annual report must contain the following information:

(a) Records of all daily meter readings and documentation to support volumes of natural gas and NGLs that are reported under this part.

(b) Records documenting any estimates of missing metered data and showing the calculations of the values used for the missing data.

(c) Calculations and worksheets used to estimate CO₂ emissions for the volumes reported under this part.

(d) Records related to the large end-users identified in §98.406(b)(6).

(e) Records relating to measured Btu content or carbon content showing specific industry standards used to develop reporter-specific higher heating values and emission factors.

(f) Records of such audits as required by Sarbanes Oxley regulations on the accuracy of measurements of volumes of natural gas and NGLs delivered to customers or on behalf of customers.

§98.408 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table NN-1 of Subpart NN—Default Factors for Calculation Methodology 1 of this Subpart

Fuel	Default High Heating Value Factor	Default CO₂ Emission Factor (kg CO₂ /MMBtu)
Natural Gas	1.027 MMBtu/Mscf	53.02
Propane	3.836 MMBtu/bbl	63.02
Normal butane	4.326 MMBtu/bbl	64.93
Ethane	3.082 MMBtu/bbl	59.58
Isobutane	3.974 MMBtu/bbl	65.08

Fuel	Default High Heating Value Factor	Default CO ₂ Emission Factor (kg CO ₂ /MMBtu)
Pentanes plus	4.620 MMBtu/bbl	66.90

Table NN-2 of Subpart NN—Lookup Default Values for Calculation Methodology 2 of this Subpart

Fuel	Unit	Default CO ₂ Emission Value (MT CO ₂ /Unit)
Natural Gas	Mscf	0.054452
Propane	Barrel	0.241745
Normal butane	Barrel	0.280887
Ethane	Barrel	0.183626
Isobutane	Barrel	0.258628
Pentanes plus	Barrel	0.309078

Subpart OO—Suppliers of Industrial Greenhouse Gases

§98.410 Definition of the source category.

(a) The industrial gas supplier source category consists of any facility that produces a fluorinated GHG or nitrous oxide, any bulk importer of fluorinated GHGs or nitrous oxide, and any bulk exporter of fluorinated GHGs or nitrous oxide.

(b) To produce a fluorinated GHG means to manufacture a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHG includes the manufacture of a fluorinated GHG for use in a process that will result in its transformation either at or outside of the production facility. Producing a fluorinated GHG also includes the creation of a fluorinated GHG (with the exception of HFC-23) that is captured and shipped off site

for any reason, including destruction. Producing a fluorinated GHG does not include the reuse or recycling of a fluorinated GHG, the creation of HFC-23 during the production of HCFC-22, or the creation of by-products that are released or destroyed at the production facility.

(c) To produce nitrous oxide means to produce nitrous oxide by thermally decomposing ammonium nitrate (NH_4NO_3). Producing nitrous oxide does not include the reuse or recycling of nitrous oxide or the creation of by-products that are released or destroyed at the production facility.

§98.411 Reporting threshold.

Any supplier of industrial greenhouse gases who meets the requirements of §98.2(a)(4) must report GHG emissions.

§98.412 GHGs to report.

You must report the GHG emissions that would result from the release of the nitrous oxide and each fluorinated GHG that you produce, import, export, transform, or destroy during the calendar year.

§98.413 Calculating GHG emissions.

(a) Calculate the total mass of each fluorinated GHG or nitrous oxide produced annually, except for amounts that are captured solely to be shipped off site for destruction, by using Equation OO-1 of this section:

$$P = \sum_{p=1}^n P_p \quad (\text{Eq. 00-1})$$

P = Mass of fluorinated GHG or nitrous oxide produced annually.

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period "p".

(b) Calculate the total mass of each fluorinated GHG or nitrous oxide produced over the period "p" by using Equation 00-2 of this section:

$$P_p = O_p - U_p \quad (\text{Eq. 00-2})$$

Where:

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period "p" (metric tons).

O_p = Mass of fluorinated GHG or nitrous oxide that is measured coming out of the production process over the period p(metric tons).

U_p = Mass of used fluorinated GHG or nitrous oxide that is added to the production process upstream of the output measurement over the period "p" (metric tons).

(c) Calculate the total mass of each fluorinated GHG or nitrous oxide transformed by using Equation 00-3 of this section:

$$T = F_T * E_T \quad (\text{Eq. 00-3})$$

Where:

T = Mass of fluorinated GHG or nitrous oxide transformed annually (metric tons).

F_T = Mass of fluorinated GHG fed into the transformation process annually (metric tons).

E_T = The fraction of the fluorinated GHG or nitrous oxide fed into the transformation process that is transformed in the process (metric tons).

(d) Calculate the total mass of each fluorinated GHG destroyed by using Equation 00-4 of this section:

$$D = F_D * DE \quad (\text{Eq. 00-4})$$

Where:

- D = Mass of fluorinated GHG destroyed annually (metric tons).
 F_D = Mass of fluorinated GHG fed into the destruction device annually (metric tons).
 DE = Destruction efficiency of the destruction device (fraction).

§98.414 Monitoring and QA/QC requirements.

(a) The mass of fluorinated GHGs or nitrous oxide coming out of the production process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(b) The mass of any used fluorinated GHGs or used nitrous oxide added back into the production process upstream of the output measurement in paragraph (a) of this section shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the mass in paragraph (a) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated GHGs for purposes of this paragraph (b) of this section and §98.413(b).

(c) The mass of fluorinated GHGs or nitrous oxide fed into the transformation process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(d) The fraction of the fluorinated GHGs or nitrous oxide fed into the transformation process that is actually transformed shall be estimated considering yield calculations or quantities of unreacted fluorinated GHGs or nitrous oxide permanently removed from the process and recovered, destroyed, or emitted.

(e) The mass of fluorinated GHG or nitrous oxide sent to another facility for transformation shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(f) The mass of fluorinated GHG sent to another facility for destruction shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG, the concentration of the fluorinated GHG shall be estimated considering current or

previous representative concentration measurements and other relevant process information. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG sent to another facility for destruction.

(g) You must estimate the share of the mass of fluorinated GHGs in paragraph (f) of this section that is comprised of fluorinated GHGs that are not included in the mass produced in §98.413(a) because they are removed from the production process as by-products or other wastes.

(h) The mass of fluorinated GHGs fed into the destruction device shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, the concentrations of fluorinated GHG being destroyed shall be estimated considering current or previous representative concentration measurements and other relevant process information. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG destroyed.

(i) Very small quantities of fluorinated GHGs that are difficult to measure because they are entrained in other media such as destroyed filters and destroyed sample containers are exempt from paragraphs (f) and (h) of this section.

(j) You must estimate the share of the mass of fluorinated GHGs in paragraph (h) of this section that is comprised of fluorinated GHGs that are not included in the mass produced in §98.413(a) because they are removed from the production process as by-products or other wastes.

(k) For purposes of Equation 00-4 of this subpart, the destruction efficiency can be equated to the destruction efficiency determined during a previous performance test of the destruction device or, if no performance test has been done, the destruction efficiency provided by the manufacturer of the destruction device.

(l) In their estimates of the mass of fluorinated GHGs destroyed, fluorinated GHG production facilities that destroy fluorinated GHGs shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(m) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures that are used to measure or calculate quantities that are to be reported under this subpart prior to the first year for which GHG emissions are reported under this part. Calibrations performed prior to the effective date of this rule satisfy this requirement. Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer. Use NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others).

§98.415 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions), a substitute data value for the missing parameter shall be used in the calculations, according to paragraph (b) of this section.

(b) For each missing value of the mass produced, fed into the production process (for used material being reclaimed), fed into the transformation process, fed into destruction devices, sent to another facility for transformation, or sent to another facility for

destruction, the substitute value of that parameter shall be a secondary mass measurement where such a measurement is available. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§98.416 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information:

(a) Each fluorinated GHG or nitrous oxide production facility shall report the following information:

(1) Mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility by process, except

for amounts that are captured solely to be shipped off site for destruction.

(2) Mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility, by process.

(3) Mass in metric tons of each fluorinated GHG destroyed at that facility, except fluorinated GHGs not included in the calculation of mass produced in §98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported under this paragraph (a)(3) of this section could include, for example, quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

(4) Mass in metric tons of each fluorinated GHG that is destroyed at that facility except GHGs not included in the calculation of mass produced in §98.413(a) because they are removed from the production process as byproducts or other wastes.

(5) Total mass in metric tons of each fluorinated GHG or nitrous oxide sent to another facility for transformation.

(6) Total mass in metric tons of each fluorinated GHG sent to another facility for destruction, except fluorinated GHGs that are not included in the mass produced

in §98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported under this paragraph (a)(6) could include, for example, fluorinated GHGs that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore sent to another facility for destruction.

(7) Total mass in metric tons of each fluorinated GHG that is sent to another facility for destruction and that is not included in the mass produced in §98.413(a) because it is removed from the production process as a byproduct or other waste.

(8) Total mass in metric tons of each reactant fed into the F-GHG or nitrous oxide production process, by process.

(9) 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.

(10) For transformation processes that do not produce an F-GHG or nitrous oxide, mass in metric tons of any fluorinated GHG or nitrous oxide fed into the transformation process, by process.

(11) Mass in metric tons of each fluorinated GHG fed into the destruction device.

(12) Mass in metric tons of each fluorinated GHG or nitrous oxide that is measured coming out of the production process, by process.

(13) Mass in metric tons of each used fluorinated GHGs or nitrous oxide added back into the production process (e.g., for reclamation), including returned heels in containers that are weighed to measure the mass in §98.414(a), by process.

(14) Names and addresses of facilities to which any nitrous oxide or fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation.

(15) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for destruction.

(16) Where missing data have been estimated pursuant to §98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(b) A fluorinated GHG production facility or importer that destroys fluorinated GHGs shall submit a one-time report containing the following information:

(1) Destruction efficiency (DE) of each destruction unit.

(2) Methods used to determine the destruction efficiency.

(3) Methods used to record the mass of fluorinated GHG destroyed.

(4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE.

(5) Name of all applicable federal or state regulations that may apply to the destruction process.

(6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.

(c) A bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their imports at the corporate level, except for shipments including less than 250 metric tons of CO₂e, transshipments, and heels that meet the conditions set forth at §98.417(e). The report shall contain the following information for each import:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk.

(2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical.

(3) Date on which the fluorinated GHGs or nitrous oxide were imported.

(4) Port of entry through which the fluorinated GHGs or nitrous oxide passed.

(5) Country from which the imported fluorinated GHGs or nitrous oxide were imported.

(6) Commodity code of the fluorinated GHGs or nitrous oxide shipped.

(7) Importer number for the shipment.

(8) Total mass in metric tons of each fluorinated GHG destroyed by the importer.

(9) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for transformation.

(10) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or

fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for destruction.

(d) A bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their exports at the corporate level, except for shipments including less than 250 metric tons of CO₂e, transshipments, and heels. The report shall contain the following information for each export:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk.

(2) Names and addresses of the exporter and the recipient of the exports.

(3) Exporter's Employee Identification Number.

(4) Commodity code of the fluorinated GHGs and nitrous oxide shipped.

(5) Date on which, and the port from which, fluorinated GHGs and nitrous oxide were exported from the United States or its territories.

(6) Country to which the fluorinated GHGs or nitrous oxide were exported.

(e) By April 1, 2011, a fluorinated GHG production facility shall submit a one-time report describing the following information:

(1) The method(s) by which the producer in practice measures the mass of fluorinated GHGs produced, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.

(2) The method(s) by which the producer in practice estimates the mass of fluorinated GHGs fed into the transformation process, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.

(3) The method(s) by which the producer in practice estimates the fraction of fluorinated GHGs fed into the transformation process that is actually transformed, and the estimated precision and accuracy of this estimate.

(4) The method(s) by which the producer in practice estimates the masses of fluorinated GHGs fed into the destruction device, including the method(s) used to estimate the concentration of the fluorinated GHGs in the destroyed material, and the estimated precision and accuracy of this estimate.

(5) The estimated percent efficiency of each production process for the fluorinated GHG produced.

§98.417 Records that must be retained.

(a) In addition to the data required by §98.3(g), the fluorinated GHG production facility shall retain the following records:

(1) Dated records of the data used to estimate the data reported under §98.416.

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the industry standards or manufacturer directions used for calibration pursuant to §98.414(j) and (k).

(b) In addition to the data required by paragraph (a) of this section, the fluorinated GHG production facility that destroys fluorinated GHGs shall keep records of test reports and other information documenting the facility's one-time destruction efficiency report and annual destruction device outlet reports in §98.416(b) and (e).

(c) In addition to the data required by §98.3(g), the bulk importer shall retain the following records substantiating each of the imports that they report:

(1) A copy of the bill of lading for the import.

(2) The invoice for the import.

(3) The U.S. Customs entry form.

(d) In addition to the data required by §98.3(g), the bulk exporter shall retain the following records substantiating each of the exports that they report:

(1) A copy of the bill of lading for the export and

(2) The invoice for the import.

(e) Every person who imports a container with a heel that is not reported under §98.416(c) shall keep records of the amount brought into the United States that document that the residual amount in each shipment is less than 10 percent of the volume of the container and will:

(1) Remain in the container and be included in a future shipment.

(2) Be recovered and transformed.

Be recovered and destroyed.

Be recovered and included in a future shipment.

§98.418 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart PP—Suppliers of Carbon Dioxide

§98.420 Definition of the source category.

(a) The carbon dioxide (CO₂) supplier source category consists of the following:

(1) Facilities with production process units that capture a CO₂ stream for purposes of supplying CO₂ for commercial applications or that capture and maintain custody of a CO₂ stream in order to sequester or otherwise inject it underground. Capture refers to the initial separation and removal of CO₂ from a manufacturing process or any other process.

(2) Facilities with CO₂ production wells that extract or produce a CO₂ stream for purposes of supplying CO₂ for commercial applications or that extract and maintain custody of a CO₂ stream in order to sequester or otherwise inject it underground.

(3) Importers or exporters of bulk CO₂.

(b) This source category is focused on upstream supply. It does not cover:

(1) Storage of CO₂ above ground or in geologic formations.

(2) Use of CO₂ in enhanced oil and gas recovery.

(3) Transportation or distribution of CO₂.

(4) Purification, compression, or processing of CO₂.

(5) On-site use of CO₂ captured on site.

(c) This source category does not include CO₂ imported or exported in equipment, such as fire extinguishers.

§98.421 Reporting threshold.

Any supplier of CO₂ who meets the requirements of §98.2(a)(4) of subpart A of this part must report the mass of CO₂ captured, extracted, imported, or exported.

§98.422 GHGs to report.

(a) Mass of CO₂ captured from each production process unit.

(b) Mass of CO₂ extracted from each CO₂ production wells.

(c) Mass of CO₂ imported.

(d) Mass of CO₂ exported.

§98.423 Calculating CO₂ Supply.

(a) Calculate the annual mass of CO₂ captured, extracted, imported, or exported through each flow meter in accordance with the procedures specified in either paragraph (a)(1) or (a)(2) of this section. If multiple flow meters are used, you shall calculate the annual mass of CO₂ for all flow meters according to the procedures specified in paragraph (a)(3) of this section.

(1) For each mass flow meter, you shall calculate quarterly the mass of CO₂ in a CO₂ stream in metric tons,

prior to any subsequent purification, processing, or compressing, by multiplying the mass flow by the composition data, according to Equation PP-1 of this section. Mass flow and composition data measurements shall be made in accordance with §98.424 of this subpart.

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} * C_{CO_{2,p,u}} \quad (\text{Eq. PP-1})$$

Where:

- $CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.
- $C_{CO_{2,p,u}}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. % CO_2).
- $Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons).
- p = Quarter of the year.
- u = Flow meter.

(2) For each volumetric flow meter, you shall calculate quarterly the mass of CO_2 in a CO_2 stream in metric tons, prior to any subsequent purification, processing, or compressing, by multiplying the volumetric flow by the concentration and density data, according to Equation PP-2 of this section. Volumetric flow, concentration and density data measurements shall be made in accordance with §98.424 of this section.

$$CO_{2,u} = \sum_{p=1}^4 Q_p * D_p * C_{CO_2,p} \quad (\text{Eq. PP-2})$$

Where:

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

$C_{CO_2,p}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. % CO_2).

Q_p = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters).

D_p = Quarterly CO_2 stream density measurement for flow meter u in quarter p (metric tons per standard cubic meter).

p = Quarter of the year.

u = Flow meter.

(3) To aggregate data, sum the mass of CO_2 for all flow meters in accordance with Equation PP-3 of this section.

$$CO_2 = \sum_{p=1}^U CO_{2,u} \quad (\text{Eq. PP-3})$$

Where:

CO_2 = Annual mass of CO_2 (metric tons) through all flow meters.

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

u = Flow meter.

(b) Importers or exporters that import or export CO_2 in containers shall calculate the total mass of CO_2 imported

or exported in metric tons, prior to any subsequent purification, processing, or compressing, based on summing the mass in each CO₂ container using weigh bills, scales, or load cells according to Equation PP-4 of this section.

$$\text{CO}_2 = \sum_{p=1}^I Q \quad (\text{Eq. PP-4})$$

Where:

CO₂ = Annual mass of CO₂ (metric tons).

Q = Annual mass in all CO₂ containers imported or exported during the reporting year (metric tons).

§98.424 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) Reporters that have a mass flow meter or volumetric flow meter installed to measure the flow of a CO₂ stream shall base calculations in §98.423 of this subpart on the installed mass flow or volumetric flow meters.

(2) Reporters that do not have a mass flow meter or volumetric flow meter installed to measure the flow of the CO₂ stream shall base calculations in §98.423 of this subpart on the flow of gas transferred off site using a mass flow meter or a volumetric flow meter located at the point of off-site transfer.

(3) Importers or exporters that import or export CO₂ in containers shall measure the mass in each CO₂ container using weigh bills, scales, or load cells and sum the mass in all containers imported or exported during the reporting year.

(4) All flow meters, scales, and load cells used to measure quantities that are reported in §98.423 of this subpart shall be operated and calibrated according to the following procedure:

(i) You shall use an appropriate standard method published by a consensus-based standards organization if such a method exists. 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), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, you shall follow industry standard practices.

(iii) You must ensure that any flow meter calibrations performed are NIST traceable.

(5) Reporters using Equation PP-2 of this subpart shall measure the density of the CO₂ stream on a quarterly basis in order to calculate the mass of the CO₂ stream according to the following procedure:

(i) You shall use an appropriate standard method published by a consensus-based standards organization to measure density if such a method exists. 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), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, you shall follow industry standard practices.

(b) Determination of concentration.

(1) Reporters using Equation PP-1 or PP-2 of this subpart shall sample the CO₂ stream on a quarterly basis to determine the composition of the CO₂ stream.

(2) Methods to measure the composition of the CO₂ stream must conform to applicable chemical analytical standards. Acceptable methods include U.S. Food and Drug

Administration food-grade specifications for CO₂ (see 21 CFR 184.1250) and ASTM standard E1747-95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications (incorporated by reference, see §98.7 of subpart A of this part).

§98.425 Procedures for estimating missing data.

(a) Whenever the quality assurance procedures in §98.424(a) of this subpart cannot be followed to measure quarterly mass flow or volumetric flow of CO₂, the most appropriate of the following missing data procedures shall be followed:

(1) A quarterly CO₂ mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during another quarter of the current reporting year.

(2) A quarterly CO₂ mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during the same quarter from the past reporting year.

(3) If a mass or volumetric flow meter is installed to measure the CO₂ stream, you may substitute data from a mass or volumetric flow meter measuring the CO₂ stream

transferred for any period during which the installed meter is inoperable.

(4) The mass or volumetric flow used for purposes of product tracking and billing according to the reporter's established procedures may be substituted for any period during which measurement equipment is inoperable.

(b) Whenever the quality assurance procedures in §98.424(b) of this subpart cannot be followed to determine concentration of the CO₂ stream, the most appropriate of the following missing data procedures shall be followed:

(1) A quarterly concentration value that is missing may be substituted with a quarterly value measured during another quarter of the current reporting year.

(2) A quarterly concentration value that is missing may be substituted with a quarterly value measured during the same quarter from the previous reporting year.

(3) The concentration used for purposes of product tracking and billing according to the reporter's established procedures may be substituted for any quarterly value.

(c) Missing data on density of the CO₂ stream shall be substituted with quarterly or annual average values from the previous calendar year.

§98.426 Data reporting requirements.

In addition to the information required by §98.3(c) of subpart A of this part, the annual report shall contain the following information, as applicable:

(a) If you use Equation PP-1 of this subpart, report the following information for each mass flow meter:

- (1) Annual mass in metric tons of CO₂.
- (2) Quarterly mass flow of CO₂.
- (3) Quarterly concentration of the CO₂ stream.
- (4) The standard used to measure CO₂ concentration.

(b) If you use Equation PP-2 of this subpart, report the following information for each volumetric flow meter:

- (1) Annual mass in metric tons of CO₂.
- (2) Quarterly volumetric flow of CO₂.
- (3) Quarterly concentration of the CO₂ stream.
- (4) Quarterly density of the CO₂ stream.
- (5) The method used to measure density.
- (6) The standard used to measure CO₂ concentration.

(c) If you use Equation PP-3 of this subpart, report the annual CO₂ mass in metric tons from all flow meters.

(d) If you use Equation PP-4 of this subpart, report at the corporate level the annual mass of CO₂ in metric tons in all CO₂ containers that are imported or exported.

(e) Each reporter shall report the following information:

(1) The type of equipment used to measure the total flow of the CO₂ stream or the total mass in CO₂ containers.

(2) The standard used to operate and calibrate the equipment reported in (e)(1) of this section.

(3) The number of days in the reporting year for which substitute data procedures were used for the following purpose:

(i) To measure quantity.

(ii) To measure concentration.

(iii) To measure density.

(f) Report the aggregated annual quantity of CO₂ in metric tons that is transferred to each of the following end use applications, if known:

(i) Food and beverage.

(ii) Industrial and municipal water/wastewater treatment.

- (iii) Metal fabrication, including welding and cutting.
- (iv) Greenhouse uses for plant growth.
- (v) Fumigants (e.g., grain storage) and herbicides.
- (vi) Pulp and paper.
- (vii) Cleaning and solvent use.
- (viii) Fire fighting.
- (ix) Transportation and storage of explosives.
- (x) Enhanced oil and natural gas recovery.
- (xi) Long-term storage (sequestration).
- (xii) Research and development.
- (xiii) Other.

(g) Each production process unit that captures a CO₂ stream for purposes of supplying CO₂ for commercial applications or in order to sequester or otherwise inject it underground when custody of the CO₂ is maintained shall report the percentage of that stream, if any, that is biomass-based during the reporting year.

§98.427 Records that must be retained.

In addition to the records required by §98.3(g) of subpart A of this part, you must retain the records

specified in paragraphs (a) through (c) of this section, as applicable.

(a) The owner or operator of a facility containing production process units must retain quarterly records of captured or transferred CO₂ streams and composition.

(b) The owner or operator of a CO₂ production well facility must maintain quarterly records of the mass flow or volumetric flow of the extracted or transferred CO₂ stream and concentration and density if volumetric flow meters are used.

(c) Importers or exporters of CO₂ must retain annual records of the mass flow, volumetric flow, and mass of CO₂ imported or exported.

§98.428 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

PART 1033—[AMENDED]

21. The authority citation for part 1033 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart C—[Amended]

22. Section 1033.205 is amended by revising paragraph (d) (8) to read as follows:

§1033.205 Applying for a certificate of conformity.

* * * * *

(d) * * *

(8) (i) All test data you obtained for each test engine or locomotive. As described in §1033.235, we may allow you to demonstrate compliance based on results from previous emission tests, development tests, or other testing information. Include data for NO_x, PM, HC, CO, and CO₂.

(ii) Report measured CO₂, N₂O, and CH₄ as described in §1033.235. Small manufacturers/remanufacturers may omit reporting N₂O and CH₄.

* * * * *

23. Section 1033.235 is amended by adding paragraph (i) to read as follows:

§1033.235 Emission testing required for certification.

* * * * *

(i) Measure CO₂ with each test. Measure CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2012 model year. Also measure N₂O with each low-hour certification test using the procedures specified in 40 CFR part 1065 for any engine family that depends on NO_x aftertreatment to meet emission standards. Small manufacturers/remanufacturers may omit measurement of N₂O and CH₄. Use the same units and modal calculations as for your other results to report a single weighted value for CO₂, N₂O, and CH₄. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/bhp-hr.
- (2) Round N₂O to the nearest 0.001 g/bhp-hr.
- (3) Round CH₄ to the nearest 0.001g/bhp-hr.

Subpart F—[Amended]

24. Section 1033.501 is amended by revising paragraph (a) introductory text to read as follows:

§1033.501 General provisions.

(a) Except as specified in this subpart, use the equipment and procedures for compression-ignition engines

in 40 CFR part 1065 to determine whether your locomotives meet the duty-cycle emission standards in §1033.101. Use the applicable duty cycles specified in this subpart. Measure emissions of all the pollutants we regulate in §1033.101 plus CO₂. Measure N₂O, and CH₄ as described in §1033.235. The general test procedure is the procedure specified in 40 CFR part 1065 for steady-state discrete-mode cycles. However, if you use the optional ramped modal cycle in §1033.520, follow the procedures for ramped modal testing in 40 CFR part 1065. The following exceptions from the 1065 procedures apply:

* * * * *

Subpart J—[Amended]

25. Section 1033.905 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§1033.905 Symbols, acronyms, and abbreviations.

* * * * *

* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

* * * * *

PART 1039—[AMENDED]

26. The authority citation for part 1039 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart C—[Amended]

27. Section 1039.205 is amended by revising paragraph (r) to read as follows:

§1039.205 What must I include in my application?

* * * * *

(r) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Report measured CO₂, N₂O, and CH₄ as described in §1039.235. Small-volume engine manufacturers may omit reporting N₂O and CH₄.

* * * * *

28. Section 1039.235 is amended by adding paragraph (g) to read as follows:

§1039.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO₂ and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065 in the 2011 and 2012 model years, respectively. Also measure N₂O with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NO_x aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N₂O and CH₄. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/kW-hr.
- (2) Round N₂O to the nearest 0.001 g/kW-hr.
- (3) Round CH₄ to the nearest 0.001g/kW-hr.

Subpart F—[Amended]

29. Section 1039.501 is amended by revising paragraph

(a) to read as follows:

§1039.501 How do I run a valid emission test?

(a) Use the equipment and procedures for compression-ignition engines in 40 CFR part 1065 to determine whether

engines meet the duty-cycle emission standards in subpart B of this part. Measure the emissions of all the exhaust constituents subject to emissions standards as specified in 40 CFR part 1065. Measure CO₂, N₂O, and CH₄ as described in §1039.235. Use the applicable duty cycles specified in §§1039.505 and 1039.510.

* * * * *

Subpart I—[Amended]

30. Section 1039.805 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§1039.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

* * * * *

PART 1042—[AMENDED]

31. The authority citation for part 1042 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart C—[Amended]

32. Section 1042.205 is amended by revising paragraph (r) to read as follows:

§1042.205 Application requirements.

* * * * *

(r) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Report measured CO₂, N₂O, and CH₄ as described in §1042.235. Small-volume engine manufacturers may omit reporting N₂O and CH₄.

* * * * *

33. Section 1042.235 is amended by adding paragraph (g) to read as follows:

§1042.235 Emission testing required for a certificate of conformity.

* * * * *

(g) Measure CO₂ with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting

in the 2011 model year. Also measure CH₄ from Category 1 and Category 2 engines with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2012 model year. Measure N₂O from Category 1 and Category 2 engines with each low-hour certification test using the procedures specified in 40 CFR part 1065 for any engine family that depends on NO_x aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N₂O and CH₄. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/kW-hr.
- (2) Round N₂O to the nearest 0.001 g/kW-hr.
- (3) Round CH₄ to the nearest 0.001g/kW-hr.

Subpart F—[Amended]

34. Section 1042.501 is amended by revising paragraph

(a) to read as follows:

§1042.501 How do I run a valid emission test?

(a) Use the equipment and procedures for compression-ignition engines in 40 CFR part 1065 to determine whether Category 1 and Category 2 engines meet the duty-cycle emission standards in §1042.101(a). Measure the emissions

of all exhaust constituents subject to emissions standards as specified in 40 CFR part 1065. Measure CO₂, N₂O, and CH₄ as described in §1042.235. Use the applicable duty cycles specified in §1042.505.

* * * * *

Subpart J—[Amended]

35. Section 1042.905 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§1042.905 Symbols, acronyms, and abbreviations.

* * * * *

* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

* * * * *

PART 1045—[AMENDED]

36. The authority citation for part 1045 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart C—[Amended]

37. Section 1045.205 is amended by revising paragraph (q) to read as follows:

§1045.205 What must I include in my application?

* * * * *

(g) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 1060 and 1065.

(2) Report measured CO₂, N₂O, and CH₄ as described in §1045.235. Small-volume engine manufacturers may omit reporting N₂O and CH₄.

* * * * *

38. Section 1045.235 is amended by adding paragraph

(g) to read as follows:

§1045.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO₂ and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N₂O with each low-hour certification test using the procedures specified in 40 CFR

part 1065 starting in the 2013 model year for any engine family that depends on NOx aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N₂O and CH₄. These measurements are not required for NTE testing. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/kW-hr.
- (2) Round N₂O to the nearest 0.001 g/kW-hr.
- (3) Round CH₄ to the nearest 0.001g/kW-hr.

Subpart F—[Amended]

39. Section 1045.501 is amended by revising paragraph (b) to read as follows:

§1045.501 How do I run a valid emission test?

* * * * *

(b) General requirements. Use the equipment and procedures for spark-ignition engines in 40 CFR part 1065 to determine whether engines meet the duty-cycle emission standards in §§1045.103 and 1045.105. Measure the emissions of all exhaust constituents subject to emissions standards as specified in 40 CFR part 1065. Measure CO₂, N₂O, and CH₄ as described in §1045.235. Use the applicable duty cycles specified in §1045.505. Section 1045.515 describes the

supplemental procedures for evaluating whether engines meet the not-to-exceed emission standards in §1045.107.

* * * * *

PART 1048—[AMENDED]

40. The authority citation for part 1048 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart C—[Amended]

41. Section 1048.205 is amended by revising paragraph (s) to read as follows:

§1048.205 What must I include in my application?

* * * * *

(s) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(2) Report measured CO₂, N₂O, and CH₄ as described in §1048.235. Small-volume engine manufacturers may omit reporting N₂O and CH₄.

* * * * *

42. Section 1048.235 is amended by adding paragraph (g) to read as follows:

§1048.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO₂ and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N₂O with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NO_x aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N₂O and CH₄. These measurements are not required for measurements using field-testing procedures. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/kW-hr.
- (2) Round N₂O to the nearest 0.001 g/kW-hr.
- (3) Round CH₄ to the nearest 0.001g/kW-hr.

Subpart F—[Amended]

43. Section 1048.501 is amended by revising paragraph (a) to read as follows:

§1048.501 How do I run a valid emission test?

(a) Use the equipment and procedures for spark-ignition engines in 40 CFR part 1065 to determine whether engines meet the duty-cycle emission standards in §1048.101(a) and (b). Measure the emissions of all the pollutants we regulate in §1048.101 using the sampling procedures specified in 40 CFR part 1065. Measure CO₂, N₂O, and CH₄ as described in §1048.235. Use the applicable duty cycles specified in §§1048.505 and 1048.510.

* * * * *

Subpart I—[Amended]

44. Section 1048.805 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§1048.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *

* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

* * * * *

PART 1051—[AMENDED]

45. The authority citation for part 1051 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart C—[Amended]

46. Section 1051.205 is amended by revising paragraph (p) to read as follows:

§1051.205 What must I include in my application?

* * * * *

(p) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 86 and 1065.

(2) Report measured CO₂, N₂O, and CH₄ as described in §1051.235. Small-volume manufacturers may omit reporting N₂O and CH₄.

* * * * *

47. Section 1051.235 is amended by adding paragraph (i) to read as follows:

§1051.235 What emission testing must I perform for my application for a certificate of conformity?

* * * * *

(i) Measure CO₂ and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N₂O with each low-hour certification test using the analytical equipment and procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NO_x aftertreatment to meet emission standards. Small-volume manufacturers may omit measurement of N₂O and CH₄; other manufacturers may provide appropriate data and/or information and omit measurement of N₂O and CH₄ as described in 40 CFR 1065.5. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

(1) Round CO₂ to the nearest 1 g/kW-hr or 1 g/km, as appropriate.

(2) Round N₂O to the nearest 0.001 g/kW-hr or 0.001 g/km, as appropriate.

(3) Round CH₄ to the nearest 0.001g/kW-hr or 0.001 g/km, as appropriate.

Subpart F—[Amended]

48. Section 1051.501 is amended by revising paragraphs (a) and (b) to read as follows:

§1051.501 What procedures must I use to test my vehicles or engines?

* * * * *

(a) Snowmobiles. For snowmobiles, use the equipment and procedures for spark-ignition engines in 40 CFR part 1065 to determine whether your snowmobiles meet the duty-cycle emission standards in §1051.103. Measure the emissions of all the pollutants we regulate in §1051.103. Measure CO₂, N₂O, and CH₄ as described in §1051.235. Use the duty cycle specified in §1051.505.

(b) Motorcycles and ATVs. For motorcycles and ATVs, use the equipment, procedures, and duty cycle in 40 CFR part 86, subpart F, to determine whether your vehicles meet the exhaust emission standards in §1051.105 or §1051.107. Measure the emissions of all the pollutants we regulate in §1051.105 or §1051.107. Measure CO₂, N₂O, and CH₄ as described in §1051.235. If we allow you to certify ATVs based on engine testing, use the equipment, procedures, and duty cycle described or referenced in the section that allows engine testing. For motorcycles with engine displacement at or below 169 cc and all ATVs, use the

driving schedule in paragraph (c) of appendix I to 40 CFR part 86. For all other motorcycles, use the driving schedule in paragraph (b) of Appendix I to part 86. With respect to vehicle-speed governors, test motorcycles and ATVs in their ungoverned configuration, unless we approve in advance testing in a governed configuration. We will only approve testing in a governed configuration if you can show that the governor is permanently installed on all production vehicles and is unlikely to be removed in use. With respect to engine-speed governors, test motorcycles and ATVs in their governed configuration. Run the test engine, with all emission-control systems operating, long enough to stabilize emission levels; you may consider emission levels stable without measurement if you accumulate 12 hours of operation.

* * * * *

Subpart I—[Amended]

49. Section 1051.805 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§1051.805 What symbols, acronyms, and abbreviations does this part use?

* * * * *
* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

* * * * *

PART 1054—[AMENDED]

50. The authority citation for part 1054 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart C—[Amended]

51. Section 1054.205 is amended by revising paragraph (p) to read as follows:

§1054.205 What must I include in my application?

* * * * *

(p) Report test results as follows:

(1) Report all test results involving measurement of pollutants for which emission standards apply. Include test results from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR parts 1060 and 1065.

(2) Report measured CO₂, N₂O, and CH₄ as described in §1054.235. Small-volume engine manufacturers may omit reporting N₂O and CH₄.

* * * * *

52. Section 1054.235 is amended by adding paragraph (g) to read as follows:

§1054.235 What exhaust emission testing must I perform for my application for a certificate of conformity?

* * * * *

(g) Measure CO₂ and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2011 and 2012 model years, respectively. Also measure N₂O with each low-hour certification test using the procedures specified in 40 CFR part 1065 starting in the 2013 model year for any engine family that depends on NO_x aftertreatment to meet emission standards. Small-volume engine manufacturers may omit measurement of N₂O and CH₄. Use the same units and modal calculations as for your other results to report a single weighted value for each constituent. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/kW-hr.
- (2) Round N₂O to the nearest 0.001 g/kW-hr.
- (3) Round CH₄ to the nearest 0.001g/kW-hr.

Subpart F—[Amended]

53. Section 1054.501 is amended by revising paragraph (b) (1) to read as follows:

§1054.501 How do I run a valid emission test?

* * * * *

(b) * * *

(1) Measure the emissions of all exhaust constituents subject to emissions standards as specified in §1054.505 and 40 CFR part 1065. Measure CO₂, N₂O, and CH₄ as described in §1054.235. See §1054.650 for special provisions that apply for variable-speed engines (including engines shipped without governors).

* * * * *

PART 1065—[AMENDED]

54. The authority citation for part 1065 continues to read as follows:

Authority: 42 U.S.C. 7401-7671q.

Subpart A—[Amended]

55. Section 1065.5 is amended by revising paragraph (a) (3) to read as follows:

§1065.5 Overview of this part 1065 and its relationship to the standard-setting part.

(a) * * *

(3) Which exhaust constituents do I need to measure?

Measure all exhaust constituents that are subject to

emission standards, any other exhaust constituents needed for calculating emission rates, and any additional exhaust constituents as specified in the standard-setting part. Alternatively, you may omit the measurement of N₂O and CH₄ for an engine, provided it is not subject to an N₂O or CH₄ emission standard. If you omit the measurement of N₂O and CH₄, you must provide other information and/or data that will give us a reasonable basis for estimating the engine's emission rates.

* * * * *

Subpart C—[Amended]

56. The center header "NO_x MEASUREMENTS" is revised to read as follows:

NO_x AND N₂O MEASUREMENTS

57. A new §1065.275 is added under the center header "NO_x AND N₂O MEASUREMENTS" to read as follows:

§1065.275 N₂O measurement devices.

(a) General component requirements. We recommend that you use an analyzer that meets the specifications in Table 1 of §1065.205. Note that your system must meet the linearity verification in §1065.307.

(b) Instrument types. You may use any of the following analyzers to measure N₂O:

(1) Nondispersive infra-red (NDIR) analyzer. You may use an NDIR analyzer that has compensation algorithms that are functions of other gaseous measurements and the engine's known or assumed fuel properties. The target value for any compensation algorithm is 0.0 % (that is, no bias high and no bias low), regardless of the uncompensated signal's bias.

(2) Fourier transform infra-red (FTIR) analyzer. You may use an FTIR analyzer that has compensation algorithms that are functions of other gaseous measurements and the engine's known or assumed fuel properties. The target value for any compensation algorithm is 0.0 % (that is, no bias high and no bias low), regardless of the uncompensated signal's bias. Use appropriate analytical procedures for interpretation of infrared spectra. For example, EPA Test Method 320 is considered a valid method for spectral interpretation (see <http://www.epa.gov/ttn/emc/methods/method320.html>).

(3) Photoacoustic analyzer. You may use a photoacoustic analyzer that has compensation algorithms that are functions of other gaseous measurements. The target value for any compensation algorithm is 0.0 % (that is, no bias high and no bias low), regardless of the uncompensated signal's bias. Use an optical wheel

configuration that gives analytical priority to measurement of the least stable components in the sample. Select a sample integration time of at least 5 seconds. Take into account sample chamber and sample line volumes when determining flush times for your instrument.

(4) Gas chromatograph analyzer. You may use a gas chromatograph with an electron-capture detector (GC-ECD) to measure N₂O concentrations of diluted exhaust for batch sampling.

(i) You may use a packed or porous layer open tubular (PLOT) column phase of suitable polarity and length to achieve adequate resolution of the N₂O peak for analysis. Examples of acceptable columns are a PLOT column consisting of bonded polystyrene-divinylbenzene or a Porapak Q packed column. Take the column temperature profile and carrier gas selection into consideration when setting up your method to achieve adequate N₂O peak resolution.

(ii) Use good engineering judgment to zero your instrument and correct for drift. You do not need to follow the specific procedures in §1065.530 and §1065.550(b) that would otherwise apply. For example, you may perform a span gas measurement before and after sample analysis without zeroing. Use the average area counts of the pre-span and post-span measurements to generate a

response factor (area counts/span gas concentration), which you then multiply by the area counts from your sample to generate the sample concentration.

(c) Interference validation. Perform interference validation for NDIR, FTIR, and photoacoustic analyzers using the procedures of §1065.375. Interference validation is not required for GC-ECD. Certain interference gases can positively interfere with NDIR, FTIR, and photoacoustic analyzers by causing a response similar to N₂O. When running the interference verification for these analyzers, use interference gases as follows:

(1) The interference gases for NDIR analyzers are CO, CO₂, H₂O, CH₄ and SO₂. Note that interference species, with the exception of H₂O, are dependent on the N₂O infrared absorption band chosen by the instrument manufacturer and should be determined independently for each analyzer.

(2) Use good engineering judgment to determine interference gases for FTIR. Note that interference species, with the exception of H₂O, are dependent on the N₂O infrared absorption band chosen by the instrument manufacturer and should be determined independently for each analyzer.

(3) The interference gases for photoacoustic analyzers are CO, CO₂, and H₂O.

Subpart D—[Amended]

58. Section 1065.303 is revised to read as follows:

§1065.303 Summary of required calibration and verifications

The following table summarizes the required and recommended calibrations and verifications described in this subpart and indicates when these have to be performed:

Table 1 of §1065.303—Summary of required calibration and verifications

Type of calibration or verification	Minimum frequency ^a
§1065.305: Accuracy, repeatability and noise	Accuracy: Not required, but recommended for initial installation. Repeatability: Not required, but recommended for initial installation. Noise: Not required, but recommended for initial installation.
§1065.307: Linearity	Speed: Upon initial installation, within 370 days before testing and after major maintenance. Torque: Upon initial installation, within 370 days before testing and after major maintenance. Electrical power: Upon initial installation, within 370 days before testing and after major maintenance. Clean gas and diluted exhaust flows: Upon initial installation, within 370 days before testing and after major maintenance, unless flow is verified by propane check or by carbon or oxygen balance. Raw exhaust flow: Upon initial installation, within 185 days before testing and after major maintenance, unless flow is verified by propane check or by carbon or oxygen balance. Gas analyzers: Upon initial installation, within 35 days before testing and after major maintenance. FTIR and photoacoustic analyzers: Upon initial installation, within 370 days before testing and after major maintenance. GC-ECD: Upon initial installation and after major maintenance. PM balance: Upon initial installation, within 370 days before testing and after major maintenance. Stand-alone pressure and temperature: Upon initial installation, within 370 days before testing and after major maintenance.

Type of calibration or verification	Minimum frequency ^a
\$1065.308: Continuous gas analyzer system response and updating-recording verification-for gas analyzers not continuously compensated for other gas species	Upon initial installation or after system modification that would effect response.
\$1065.309: Continuous gas analyzer system-response and updating-recording verification-for gas analyzers continuously compensated for other gas species	Upon initial installation or after system modification that would effect response.
\$1065.310: Torque	Upon initial installation and after major maintenance.
\$1065.315: Pressure, temperature, dewpoint	Upon initial installation and after major maintenance.
\$1065.320: Fuel flow	Upon initial installation and after major maintenance.
\$1065.325: Intake flow	Upon initial installation and after major maintenance.
\$1065.330: Exhaust flow	Upon initial installation and after major maintenance.
\$1065.340: Diluted exhaust flow (CVS)	Upon initial installation and after major maintenance.
\$1065.341: CVS and batch sampler verification ^b	Upon initial installation, within 35 days before testing, and after major maintenance.
\$1065.345: Vacuum leak	Before each laboratory test according to subpart F of this part and before each field test according to subpart J of this part.
\$1065.350: CO ₂ NDIR H ₂ O interference	Upon initial installation and after major maintenance.
\$1065.355: CO NDIR CO ₂ and H ₂ O interference	Upon initial installation and after major maintenance.
\$1065.360: FID calibration, THC FID optimization, and THC FID verification.	Calibrate all FID analyzers: upon initial installation and after major maintenance. Optimize and determine CH ₄ response for THC FID analyzers: upon initial installation and after major maintenance. Verify CH ₄ response for THC FID analyzers: upon initial installation, within 185 days before testing, and after major maintenance.
\$1065.362: Raw exhaust FID O ₂ interference	For all FID analyzers: upon initial installation, and after major maintenance. For THC FID analyzers: upon initial installation, after major maintenance, and after FID optimization according to §1065.360.
\$1065.365: Nonmethane cutter penetration	Upon initial installation, within 185 days before testing, and after major maintenance.
\$1065.370: CLD CO ₂ and H ₂ O quench	Upon initial installation and after major maintenance.
\$1065.372: NDUV HC and H ₂ O interference	Upon initial installation and after major maintenance.
\$1065.375: N ₂ O analyzer interference	Upon initial installation and after major maintenance.
\$1065.376: Chiller NO ₂ penetration	Upon initial installation and after major maintenance.
\$1065.378: NO ₂ -to-NO converter	Upon initial installation, within 35 days

Type of calibration or verification	Minimum frequency ^a
conversion	before testing, and after major maintenance.
§1065.390: PM balance and weighing	Independent verification: upon initial installation, within 370 days before testing, and after major maintenance. Zero, span, and reference sample verifications: within 12 hours of weighing, and after major maintenance.
§1065.395: Inertial PM balance and weighing	Independent verification: upon initial installation, within 370 days before testing, and after major maintenance. Other verifications: upon initial installation and after major maintenance.

^aPerform calibrations and verifications more frequently, according to measurement system manufacturer instructions and good engineering judgment.

^bThe CVS verification described in §1065.341 is not required for systems that agree within ± 2% based on a chemical balance of carbon or oxygen of the intake air, fuel, and diluted exhaust.

59. Section 1065.307 is amended by revising paragraph

(c) (6) to read as follows:

§1065.307 Linearity verification.

* * * * *

(c) * * *

(6) For all measured quantities, use instrument

manufacturer recommendations and good engineering judgment

to select reference values, y_{refi} , that cover a range of

values that you expect would prevent extrapolation beyond

these values during emission testing. We recommend

selecting a zero reference signal as one of the reference

values of the linearity verification. For stand-alone

pressure and temperature linearity verifications and for

GC-ECD linearity verifications, we recommend at least three

reference values. For all other linearity verifications

select at least ten reference values.

* * * * *

60. Section 1065.365 is amended by revising paragraphs (d), (e), and (f) to read as follows:

§1065.365 Nonmethane cutter penetration fractions.

* * * * *

(d) Procedure for a FID calibrated with the NMC. The method described in this paragraph (d) is recommended over the procedures specified in paragraphs (e) and (f) of this section. If your FID arrangement is such that a FID is always calibrated to measure CH₄ with the NMC, then span that FID with the NMC using a CH₄ span gas, set the product of that FID's CH₄ response factor and CH₄ penetration fraction, $RFPF_{CH_4[NMC-FID]}$, equal to 1.0 for all emission calculations, and determine its combined ethane (C₂H₆) response factor and penetration fraction, $RFPF_{C_2H_6[NMC-FID]}$ as follows:

(1) Select CH₄ and C₂H₆ analytical gas mixtures and ensure that both mixtures meet the specifications of §1065.750. Select a CH₄ concentration that you would use for spanning the FID during emission testing and select a C₂H₆ concentration that is typical of the peak NMHC concentration expected at the hydrocarbon standard or equal to the THC analyzer's span value.

(2) Start, operate, and optimize the nonmethane cutter according to the manufacturer's instructions, including any temperature optimization.

(3) Confirm that the FID analyzer meets all the specifications of §1065.360.

(4) Start and operate the FID analyzer according to the manufacturer's instructions.

(5) Zero and span the FID with the nonmethane cutter as you would during emission testing. Span the FID through the cutter by using CH₄ span gas.

(6) Introduce the C₂H₆ analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(7) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(8) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(9) Divide the mean C₂H₆ concentration by the reference concentration of C₂H₆, converted to a C₁ basis.

The result is the C_2H_6 combined response factor and penetration fraction, $RFPF_{C_2H_6[NMC-FID]}$. Use this combined response factor and penetration fraction and the product of the CH_4 response factor and CH_4 penetration fraction, $RFPF_{CH_4[NMC-FID]}$, set to 1.0 in emission calculations according to §1065.660(b)(2)(i), §1065.660(c)(1)(i), or §1065.665, as applicable.

(e) Procedure for a FID calibrated with propane, bypassing the NMC. If you use a single FID for THC and CH_4 determination with an NMC that is calibrated with propane, C_3H_8 , by bypassing the NMC, determine its penetration fractions, $PF_{C_2H_6[NMC-FID]}$ and $PF_{CH_4[NMC-FID]}$, as follows:

(1) Select CH_4 and C_2H_6 analytical gas mixtures and ensure that both mixtures meet the specifications of §1065.750. Select a CH_4 concentration that you would use for spanning the FID during emission testing and select a C_2H_6 concentration that is typical of the peak NMHC concentration expected at the hydrocarbon standard or equal to the THC analyzer's span value.

(2) Start and operate the nonmethane cutter according to the manufacturer's instructions, including any temperature optimization.

(3) Confirm that the FID analyzer meets all the specifications of §1065.360.

(4) Start and operate the FID analyzer according to the manufacturer's instructions.

(5) Zero and span the FID as you would during emission testing. Span the FID by bypassing the cutter and by using C_3H_8 span gas.

(6) Introduce the C_2H_6 analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(7) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(8) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(9) Reroute the flow path to bypass the nonmethane cutter, introduce the C_2H_6 analytical gas mixture, and repeat the steps in paragraph (e) (7) through (e) (8) of this section.

(10) Divide the mean C_2H_6 concentration measured through the nonmethane cutter by the mean C_2H_6 concentration measured after bypassing the nonmethane cutter. The result

is the C_2H_6 penetration fraction, $PF_{C_2H_6[NMC-FID]}$. Use this penetration fraction according to §1065.660(b)(2)(ii), §1065.660(c)(1)(ii), or §1065.665, as applicable.

(11) Repeat the steps in paragraphs (e)(6) through (e)(10) of this section, but with the CH_4 analytical gas mixture instead of C_2H_6 . The result will be the CH_4 penetration fraction, $PF_{CH_4[NMC-FID]}$. Use this penetration fraction according to §1065.660(b)(2)(ii), §1065.660(c)(1)(ii), or §1065.665, as applicable.

(f) Procedure for a FID calibrated with methane, bypassing the NMC. If you use a FID with an NMC that is calibrated with methane, CH_4 , by bypassing the NMC, determine its combined ethane (C_2H_6) response factor and penetration fraction, $RF_{PF_{C_2H_6[NMC-FID]}}$, as well as its CH_4 penetration fraction, $PF_{CH_4[NMC-FID]}$, as follows:

(1) Select CH_4 and C_2H_6 analytical gas mixtures and ensure that both mixtures meet the specifications of §1065.750. Select a CH_4 concentration that you would use for spanning the FID during emission testing and select a C_2H_6 concentration that is typical of the peak NMHC concentration expected at the hydrocarbon standard or equal to the THC analyzer's span value.

(2) Start and operate the nonmethane cutter according to the manufacturer's instructions, including any temperature optimization.

(3) Confirm that the FID analyzer meets all the specifications of §1065.360.

(4) Start and operate the FID analyzer according to the manufacturer's instructions.

(5) Zero and span the FID as you would during emission testing. Span the FID by bypassing the cutter and by using CH₄ span gas. Note that you must span the FID on a C₁ basis. For example, if your span gas has a methane reference value of 100 µmol/mol, the correct FID response to that span gas is 100 µmol/mol because there is one carbon atom per CH₄ molecule.

(6) Introduce the C₂H₆ analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(7) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(8) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(9) Divide the mean C_2H_6 concentration by the reference concentration of C_2H_6 , converted to a C_1 basis. The result is the C_2H_6 combined response factor and penetration fraction, $RFPF_{C_2H_6[NMC-FID]}$. Use this combined response factor and penetration fraction according to §1065.660(b)(2)(iii), §1065.660(c)(1)(iii), or §1065.665, as applicable.

(10) Introduce the CH_4 analytical gas mixture upstream of the nonmethane cutter. Use good engineering judgment to address the effect of hydrocarbon contamination if your point of introduction is vastly different from the point of zero/span gas introduction.

(11) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the nonmethane cutter and to account for the analyzer's response.

(12) While the analyzer measures a stable concentration, record 30 seconds of sampled data. Calculate the arithmetic mean of these data points.

(13) Reroute the flow path to bypass the nonmethane cutter, introduce the CH₄ analytical gas mixture, and repeat the steps in paragraphs (e) (11) and (12) of this section.

(14) Divide the mean CH₄ concentration measured through the nonmethane cutter by the mean CH₄ concentration measured after bypassing the nonmethane cutter. The result is the CH₄ penetration fraction, $PF_{CH_4[NMC-FID]}$. Use this penetration fraction according to §1065.660 (b) (2) (iii), §1065.660 (c) (1) (iii), or §1065.665, as applicable.

61. The center header "NO_x MEASUREMENTS" is revised to read as follows:

NO_x and N₂O MEASUREMENTS

62. A new §1065.375 is added under the center header "NO_x AND N₂O MEASUREMENTS" to read as follows:

§1065.375 Interference verification for N₂O analyzers.

(a) Scope and frequency. See §1065.275 to determine whether you need to verify the amount of interference after initial analyzer installation and after major maintenance.

(b) Measurement principles. Interference gasses can positively interfere with certain analyzers by causing a response similar to N₂O. If the analyzer uses compensation algorithms that utilize measurements of other gases to meet this interference verification, simultaneously conduct

these other measurements to test the compensation algorithms during the analyzer interference verification.

(c) System requirements. Analyzers must have combined interference that is within (0.0 ± 1.0) $\mu\text{mol/mol}$. We strongly recommend a lower interference that is within (0.0 ± 0.5) $\mu\text{mol/mol}$.

(d) Procedure. Perform the interference verification as follows:

(1) Start, operate, zero, and span the N_2O analyzer as you would before an emission test. If the sample is passed through a dryer during emission testing, you may run this verification test with the dryer if it meets the requirements of §1065.342. Operate the dryer at the same conditions as you will for an emission test. You may also run this verification test without the sample dryer.

(2) Create a humidified test gas by bubbling a multi component span gas that incorporates the target interference species and meets the specifications in §1065.750 through distilled water in a sealed vessel. If the sample is not passed through a dryer during emission testing, control the vessel temperature to generate an H_2O level at least as high as the maximum expected during emission testing. If the sample is passed through a dryer during emission testing, control the vessel temperature to

generate an H₂O level at least as high as the level determined in §1065.145(e)(2) for that dryer. Use interference span gas concentrations that are at least as high as the maximum expected during testing.

(3) Introduce the humidified interference test gas into the sample system. You may introduce it downstream of any sample dryer, if one is used during testing.

(4) If the sample is not passed through a dryer during this verification test, measure the water mole fraction, x_{H_2O} , of the humidified interference test gas as close as possible to the inlet of the analyzer. For example, measure dewpoint, T_{dew} , and absolute pressure, p_{total} , to calculate x_{H_2O} . Verify that the water content meets the requirement in paragraph (d)(2) of this section. If the sample is passed through a dryer during this verification test, you must verify that the water content of the humidified test gas downstream of the vessel meets the requirement in paragraph (d)(2) of this section based on either direct measurement of the water content (e.g., dewpoint and pressure) or an estimate based on the vessel pressure and temperature. Use good engineering judgment to estimate the water content. For example, you may use previous direct measurements of water content to verify the vessel's level of saturation.

(5) If a sample dryer is not used in this verification test, use good engineering judgment to prevent condensation in the transfer lines, fittings, or valves from the point where x_{H_2O} is measured to the analyzer. We recommend that you design your system so that the wall temperatures in the transfer lines, fittings, and valves from the point where x_{H_2O} is measured to the analyzer are at least 5 °C above the local sample gas dewpoint.

(6) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the transfer line and to account for analyzer response.

(7) While the analyzer measures the sample's concentration, record its output for 30 seconds. Calculate the arithmetic mean of this data.

(8) The analyzer meets the interference verification if the result of paragraph (d) (7) of this section meets the tolerance in paragraph (c) of this section.

(9) You may also run interference procedures separately for individual interference gases. If the interference gas levels used are higher than the maximum levels expected during testing, you may scale down each observed interference value by multiplying the observed interference by the ratio of the maximum expected concentration value to the actual value used during this

procedure. You may run separate interference concentrations of H₂O (down to 0.025 mol/mol H₂O content) that are lower than the maximum levels expected during testing, but you must scale up the observed H₂O interference by multiplying the observed interference by the ratio of the maximum expected H₂O concentration value to the actual value used during this procedure. The sum of the scaled interference values must meet the tolerance specified in paragraph (c) of this section.

Subpart F—[RESERVED]

63. Section 1065.550 is amended by revising paragraph (b) to read as follows:

§1065.550 Gas analyzer range validation, drift validation, and drift correction.

* * * * *

(b) Drift validation and drift correction. Calculate two sets of brake-specific emission results for each test interval. Calculate one set using the data before drift correction and calculate the other set after correcting all the data for drift according to §1065.672. Use the two sets of brake-specific emission results to validate the duty cycle for drift as follows:

(1) The duty cycle is validated for drift if you satisfy one of the following criteria:

(i) For each test interval of the duty cycle and for each measured exhaust constituent, the difference between the uncorrected and the corrected brake-specific emission values over the test interval is within $\pm 4\%$ of the uncorrected value or applicable emission standard, whichever is greater. This requirement also applies for CO_2 , whether or not an emission standard applies for CO_2 . Where no emission standard applies for CO_2 , the difference must be within $\pm 4\%$ of the uncorrected value. See paragraph (b)(4) of this section for exhaust constituents other than CO_2 for which no emission standard applies.

(ii) For the entire duty cycle and for each regulated pollutant, the difference between the uncorrected and corrected composite brake-specific emission values over the entire duty cycle is within $\pm 4\%$ of the uncorrected value or the applicable emission standard, whichever is greater. Note that for purposes of drift validation using composite brake-specific emission values over the entire duty cycle, leave unaltered any negative emission results over a given test interval (i.e., do not set them to zero). A third calculation of composite brake-specific emission values is required for final reporting. This calculation uses drift-corrected mass (or mass rate) values from each test interval and sets any negative mass (or mass rate) values

to zero before calculating the composite brake-specific emission values over the entire duty cycle. This requirement also applies for CO₂, whether or not an emission standard applies for CO₂. Where no emission standard applies for CO₂, the difference must be within ±4 % of the uncorrected value. See paragraph (b)(3) of this section for exhaust constituents other than CO₂ for which no emission standard applies.

* * * * *

(3) [Reserved]

(4) The provisions of this paragraph (b)(3) apply for measurement of pollutants other than CO₂ for which no emission standard applies. You may use measurements that do not meet the drift validation criteria specified in paragraph (b)(1). For example, this allowance may be appropriate for measuring and reporting very low concentrations of CH₄ and N₂O as long as no emission standard applies for these compounds.

Subpart G—[Amended]

64. Section 1065.601 is amended by revising paragraph (a)(1) to read as follows:

§1065.601 Overview.

(a) * * *

(1) Use the signals recorded before, during, and after an emission test to calculate brake-specific emissions of each measured exhaust constituent.

* * * * *

65. Section 1065.660 is revised to read as follows:

§1065.660 THC, NMHC, and CH₄ determination.

(a) THC determination and THC/CH₄ initial contamination corrections. (1) If we require you to determine THC emissions, calculate $x_{\text{THC}[\text{THC-FID}]\text{cor}}$ using the initial THC contamination concentration $x_{\text{THC}[\text{THC-FID}]\text{init}}$ from §1065.520 as follows:

$$x_{\text{THC}[\text{THC-FID}]\text{cor}} = x_{\text{THC}[\text{THC-FID}]\text{uncor}} - x_{\text{THC}[\text{THC-FID}]\text{init}}$$

Eq. 1065.660-1

Example:

$$x_{\text{THCuncor}} = 150.3 \text{ } \mu\text{mol/mol}$$

$$x_{\text{THCinit}} = 1.1 \text{ } \mu\text{mol/mol}$$

$$x_{\text{THCcor}} = 150.3 - 1.1$$

$$x_{\text{THCcor}} = 149.2 \text{ } \mu\text{mol/mol}$$

(2) For the NMHC determination described in paragraph (b) of this section, correct $x_{\text{THC}[\text{THC-FID}]}$ for initial HC contamination using Eq. 1065.660-1. You may correct $x_{\text{THC}[\text{NMHC-FID}]}$ for initial contamination of the CH₄ sample train using Eq. 1065.660-1, substituting in CH₄ concentrations for THC.

(3) For the CH₄ determination described in paragraph (c) of this section, you may correct $x_{\text{THC}[\text{NMHC-FID}]}$ for initial

contamination of the CH₄ sample train using Eq. 1065.660-1, substituting in CH₄ concentrations for THC.

(b) NMHC determination. Use one of the following to determine NMHC concentration, x_{NMHC} :

(1) If you do not measure CH₄, you may determine NMHC concentrations as described in §1065.650(c)(1)(vi).

(2) For nonmethane cutters, calculate x_{NMHC} using the nonmethane cutter's penetration fractions (*PF*) of CH₄ and C₂H₆ from §1065.365, and using the HC contamination and dry-to-wet corrected THC concentration $x_{\text{THC}[\text{THC-FID}]_{\text{cor}}}$ as determined in paragraph (a) of this section.

(i) Use the following equation for penetration fractions determined using an NMC configuration as outlined in §1065.365(d):

$$x_{\text{NMHC}} = \frac{x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} - x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} \cdot RF_{\text{CH}_4[\text{THC-FID}]}}{1 - RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} \cdot RF_{\text{CH}_4[\text{THC-FID}]}}$$

Eq. 1065.660-2

Where:

x_{NMHC}	=	concentration of NMHC.
$x_{\text{THC}[\text{THC-FID}]_{\text{cor}}}$	=	concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.
$x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}}$	=	concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.
$RF_{\text{CH}_4[\text{THC-FID}]}$	=	response factor of THC FID to CH ₄ , according to §1065.360(d).

$RFPF_{C_2H_6[NMC-FID]}$ = nonmethane cutter combined ethane response factor and penetration fraction, according to §1065.365(d).

Example:

$$x_{THC[THC-FID]_{cor}} = 150.3 \text{ } \mu\text{mol/mol}$$

$$x_{THC[NMC-FID]_{cor}} = 20.5 \text{ } \mu\text{mol/mol}$$

$$RFPF_{C_2H_6[NMC-FID]} = 0.019$$

$$RF_{CH_4[THC-FID]} = 1.05$$

$$x_{NMHC} = \frac{150.3 - 20.5 \cdot 1.05}{1 - 0.019 \cdot 1.05}$$

$$x_{NMHC} = 131.4 \text{ } \mu\text{mol/mol}$$

(ii) For penetration fractions determined using an NMC configuration as outlined in section §1065.365(e), use the following equation:

$$x_{NMHC} = \frac{x_{THC[THC-FID]_{cor}} \cdot PF_{CH_4[NMC-FID]_{cor}} - x_{THC[NMC-FID]}}{PF_{CH_4[NMC-FID]} - PF_{C_2H_6[NMC-FID]}}$$

Eq. 1065.660-3

Where:

x_{NMHC} = concentration of NMHC.

$x_{THC[THC-FID]_{cor}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$PF_{CH_4[NMC-FID]}$ = nonmethane cutter CH_4 penetration fraction, according to §1065.365(e).

$x_{THC[NMC-FID]_{cor}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the THC FID during sampling through the NMC.

$PF_{C_2H_6[NMC-FID]}$ = nonmethane cutter ethane penetration fraction, according to §1065.365(e).

Example:

$$x_{THC[THC-FID]_{cor}} = 150.3 \text{ } \mu\text{mol/mol}$$

$$PF_{CH_4[NMC-FID]} = 0.990$$

$$x_{THC[NMC-FID]_{cor}} = 20.5 \text{ } \mu\text{mol/mol}$$

$$PF_{C_2H_6[NMC-FID]} = 0.020$$

$$x_{\text{NMHC}} = \frac{150.3 \cdot 0.990 - 20.5}{0.990 - 0.020}$$

$$x_{\text{NMHC}} = 132.3 \text{ } \mu\text{mol/mol}$$

(iii) For penetration fractions determined using an NMC configuration as outlined in section §1065.365(f), use the following equation:

$$x_{\text{NMHC}} = \frac{x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} \cdot PF_{\text{CH}_4[\text{NMC-FID}]} - x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} \cdot RF_{\text{CH}_4[\text{THC-FID}]}}{PF_{\text{CH}_4[\text{NMC-FID}]} - RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} \cdot RF_{\text{CH}_4[\text{THC-FID}]}}$$

Eq. 1065.660-4

Where:

x_{NMHC} = concentration of NMHC.

$x_{\text{THC}[\text{THC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.

$PF_{\text{CH}_4[\text{NMC-FID}]}$ = nonmethane cutter CH_4 penetration fraction, according to §1065.365(f).

$x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the THC FID during sampling through the NMC.

$RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]}$ = nonmethane cutter CH_4 combined ethane response factor and penetration fraction, according to §1065.365(f).

$RF_{\text{CH}_4[\text{THC-FID}]}$ = response factor of THC FID to CH_4 , according to §1065.360(d).

Example:

$$x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} = 150.3 \text{ } \mu\text{mol/mol}$$

$$PF_{\text{CH}_4[\text{NMC-FID}]} = 0.990$$

$$x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} = 20.5 \text{ } \mu\text{mol/mol}$$

$$RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} = 0.019$$

$$RF_{\text{CH}_4[\text{THC-FID}]} = 0.980$$

$$x_{\text{NMHC}} = \frac{150.3 \cdot 0.990 - 20.5 \cdot 0.980}{0.990 - 0.019 \cdot 0.980}$$

$$x_{\text{NMHC}} = 132.5 \text{ } \mu\text{mol/mol}$$

(3) For a gas chromatograph, calculate x_{NMHC} using the THC analyzer's response factor (RF) for CH_4 , from §1065.360, and the HC contamination and dry-to-wet corrected initial THC concentration $x_{\text{THC}[\text{THC-FID}]_{\text{cor}}}$ as determined in paragraph (a) of this section as follows:

* * * * *

(c) CH_4 determination. Use one of the following methods to determine CH_4 concentration, x_{CH_4} :

(1) For nonmethane cutters, calculate x_{CH_4} using the nonmethane cutter's penetration fractions (PF) of CH_4 and C_2H_6 from §1065.365, using the dry-to-wet corrected CH_4 concentration $x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}}$ as determined in paragraph (a) of this section and optionally using the CH_4 contamination correction under paragraph (a) of this section.

(i) Use the following equation for penetration fractions determined using an NMC configuration as outlined in §1065.365 (d):

$$x_{\text{CH}_4} = \frac{x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} - x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} \cdot RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]}}{1 - RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} \cdot RF_{\text{CH}_4[\text{THC-FID}]}}$$

Eq. 1065.660-6

Where:

x_{CH_4} = concentration of CH_4 .
 $x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.

- $x_{\text{THC}[\text{THC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.
- $RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]}$ = the combined ethane response factor and penetration fraction of the nonmethane cutter, according to §1065.365(d).
- $RF_{\text{CH}_4[\text{THC-FID}]}$ = response factor of THC FID to CH_4 , according to §1065.360(d).

Example:

$$\begin{aligned}
 x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} &= 10.4 \text{ } \mu\text{mol/mol} \\
 x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} &= 150.3 \text{ } \mu\text{mol/mol} \\
 RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} &= 0.019 \\
 RF_{\text{CH}_4[\text{THC-FID}]} &= 1.05 \\
 x_{\text{CH}_4} &= \frac{10.4 - 150.3 \cdot 0.019}{1 - 0.019 \cdot 1.05} \\
 x_{\text{CH}_4} &= 7.69 \text{ } \mu\text{mol/mol}
 \end{aligned}$$

(ii) For penetration fractions determined using an NMC configuration as outlined in §1065.365(e), use the following equation:

$$x_{\text{CH}_4} = \frac{x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} - x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} \cdot PF_{\text{C}_2\text{H}_6[\text{NMC-FID}]}}{RF_{\text{CH}_4[\text{THC-FID}]} \cdot (PF_{\text{CH}_4[\text{NMC-FID}]} - PF_{\text{C}_2\text{H}_6[\text{NMC-FID}]})}$$

Eq. 1065.660-7

Where:

- x_{CH_4} = concentration of CH_4 .
- $x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.
- $x_{\text{THC}[\text{THC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.
- $PF_{\text{C}_2\text{H}_6[\text{NMC-FID}]}$ = nonmethane cutter ethane penetration fraction, according to §1065.365(e).
- $RF_{\text{CH}_4[\text{THC-FID}]}$ = response factor of THC FID to CH_4 , according to §1065.360(d).
- $PF_{\text{CH}_4[\text{NMC-FID}]}$ = nonmethane cutter CH_4 penetration fraction, according to §1065.365(e).

Example:

$$\begin{aligned}
x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} &= 10.4 \text{ } \mu\text{mol/mol} \\
x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} &= 150.3 \text{ } \mu\text{mol/mol} \\
RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} &= 0.020 \\
RF_{\text{CH}_4[\text{THC-FID}]} &= 1.05 \\
PF_{\text{CH}_4[\text{NMC-FID}]} &= 0.990
\end{aligned}$$

$$x_{\text{CH}_4} = \frac{10.4 - 150.3 \cdot 0.020}{1.05 \cdot (0.990 - 0.020)}$$

$$x_{\text{CH}_4} = 7.25 \text{ } \mu\text{mol/mol}$$

(iii) For penetration fractions determined using an NMC configuration as outlined in §1065.365(f), use the following equation:

$$x_{\text{CH}_4} = \frac{x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} - x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} \cdot RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]}}{PF_{\text{CH}_4[\text{NMC-FID}]} - RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} \cdot RF_{\text{CH}_4[\text{THC-FID}]}}$$

Eq. 1065.660-8

Where:

- x_{CH_4} = concentration of CH_4 .
- $x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination (optional) and dry-to-wet corrected, as measured by the NMC FID during sampling through the NMC.
- $x_{\text{THC}[\text{THC-FID}]_{\text{cor}}}$ = concentration of THC, HC contamination and dry-to-wet corrected, as measured by the THC FID during sampling while bypassing the NMC.
- $RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]}$ = the combined ethane response factor and penetration fraction of the nonmethane cutter, according to §1065.365(f).
- $PF_{\text{CH}_4[\text{NMC-FID}]}$ = nonmethane cutter CH_4 penetration fraction, according to §1065.365(f).
- $RF_{\text{CH}_4[\text{THC-FID}]}$ = response factor of THC FID to CH_4 , according to §1065.360(d).

Example:

$$\begin{aligned}
x_{\text{THC}[\text{NMC-FID}]_{\text{cor}}} &= 10.4 \text{ } \mu\text{mol/mol} \\
x_{\text{THC}[\text{THC-FID}]_{\text{cor}}} &= 150.3 \text{ } \mu\text{mol/mol} \\
RFPF_{\text{C}_2\text{H}_6[\text{NMC-FID}]} &= 0.019 \\
PF_{\text{CH}_4[\text{NMC-FID}]} &= 0.990 \\
RF_{\text{CH}_4[\text{THC-FID}]} &= 1.05
\end{aligned}$$

$$x_{\text{CH}_4} = \frac{10.4 - 150.3 \cdot 0.019}{0.990 - 0.019 \cdot 1.05}$$

$$x_{\text{CH}_4} = 7.78 \text{ } \mu\text{mol/mol}$$

(2) For a gas chromatograph, x_{CH_4} is the actual dry-to-wet corrected CH_4 concentration as measured by the analyzer.

Subpart H—[Amended]

66. Section 1065.750 is amended by revising paragraph (a) (1) (ii) and adding paragraph (a) (3) (xi) to read as follows:

§1065.750 Analytical Gases.

* * * * *

(a) * * *

(1) * * *

(ii) Contamination as specified in the following

table:

Table 1 of §1065.750—General specifications for purified gases.

Constituent	Purified Synthetic Air ¹	Purified N ₂ ¹
THC (C ₁ equivalent)	< 0.05 $\mu\text{mol/mol}$	< 0.05 $\mu\text{mol/mol}$
CO	< 1 $\mu\text{mol/mol}$	< 1 $\mu\text{mol/mol}$
CO ₂	< 10 $\mu\text{mol/mol}$	< 10 $\mu\text{mol/mol}$
O ₂	0.205 to 0.215 mol/mol	< 2 $\mu\text{mol/mol}$
NO _x	< 0.02 $\mu\text{mol/mol}$	< 0.02 $\mu\text{mol/mol}$
N ₂ O ²	< 0.05 $\mu\text{mol/mol}$	< 0.05 $\mu\text{mol/mol}$

¹We do not require these levels of purity to be NIST-traceable.

²The N₂O limit applies only if the standard-setting part requires you to report N₂O.

* * * * *

(3) * * *

(xi) N₂O, balance purified synthetic air.

* * * * *

67. Section 1065.1001 is amended by revising the definition for "Oxides of nitrogen" to read as follows:

§1065.1001 Definitions.

* * * * *

Oxides of nitrogen means NO and NO₂ as measured by the procedures specified in §1065.270. Oxides of nitrogen are expressed quantitatively as if the NO is in the form of NO₂, such that you use an effective molar mass for all oxides of nitrogen equivalent to that of NO₂.

* * * * *

68. Section 1065.1005 is amended by revising paragraphs (b), (f) (2), and (g) to read as follows:

§1065.1005 Symbols, abbreviations, acronyms, and units of measure.

* * * * *

(b) Symbols for chemical species. This part uses the following symbols for chemical species and exhaust constituents:

Symbol	Species
Ar	argon
C	carbon
CH ₄	methane
C ₂ H ₆	ethane
C ₃ H ₈	propane
C ₄ H ₁₀	butane
C ₅ H ₁₂	pentane
CO	carbon monoxide
CO ₂	carbon dioxide
H	atomic hydrogen

Symbol	Species
H ₂	molecular hydrogen
H ₂ O	water
He	helium
⁸⁵ Kr	krypton 85
N ₂	molecular nitrogen
NMHC	nonmethane hydrocarbon
NMHCE	nonmethane hydrocarbon equivalent
NO	nitric oxide
NO ₂	nitrogen dioxide
NO _x	oxides of nitrogen
N ₂ O	nitrous oxide
NOTHC	nonoxygenated hydrocarbon
O ₂	molecular oxygen
OHC	oxygenated hydrocarbon
²¹⁰ Po	polonium 210
PM	particulate mass
S	sulfur
SO ₂	sulfur dioxide
THC	total hydrocarbon
ZrO ₂	zirconium dioxide

* * * * *

(f) * * *

(2) This part uses the following molar masses or effective molar masses of chemical species:

Symbol	Quantity	g/mol (10 ⁻³ ·kg·mol ⁻¹)
M_{air}	molar mass of dry air 1	28.96559
M_{Ar}	molar mass of argon	39.948
M_{C}	molar mass of carbon	12.0107
M_{CO}	molar mass of carbon monoxide	28.0101
M_{CO_2}	molar mass of carbon dioxide	44.0095
M_{H}	molar mass of atomic hydrogen	1.00794
M_{H_2}	molar mass of molecular hydrogen	2.01588
$M_{\text{H}_2\text{O}}$	molar mass of water	18.01528
M_{He}	molar mass of helium	4.002602
M_{N}	molar mass of atomic nitrogen	14.0067
M_{N_2}	molar mass of molecular nitrogen	28.0134
M_{NMHC}	effective molar mass of nonmethane hydrocarbon ²	13.875389
M_{NMHCE}	effective molar mass of nonmethane equivalent hydrocarbon ²	13.875389
M_{NO_x}	effective molar mass of oxides of nitrogen ³	46.0055
$M_{\text{N}_2\text{O}}$	effective molar mass of nitrous oxide	44.0128

Symbol	Quantity	$\frac{\text{g}}{\text{mol}}$ ($10^{-3} \cdot \text{kg} \cdot \text{mol}^{-1}$)
M_{O}	molar mass of atomic oxygen	15.9994
M_{O_2}	molar mass of molecular oxygen	31.9988
$M_{\text{C}_3\text{H}_8}$	molar mass of propane	44.09562
M_{S}	molar mass of sulfur	32.065
M_{THC}	effective molar mass of total hydrocarbon ²	13.875389
M_{THCE}	effective molar mass of total hydrocarbon equivalent ²	13.875389

¹See paragraph (f) (1) of this section for the composition of dry air.

²The effective molar masses of THC, THCE, NMHC, and NMHCE are defined by an atomic hydrogen-to-carbon ratio, α , of 1.85.

³The effective molar mass of NO_x is defined by the molar mass of nitrogen dioxide, NO₂.

* * * * *

(g) Other acronyms and abbreviations. This part uses

the following additional abbreviations and acronyms:

ASTM	American Society for Testing and Materials.
BMD	bag mini-diluter.
BSFC	brake-specific fuel consumption.
CARB	California Air Resources Board.
CFR	Code of Federal Regulations.
CFV	critical-flow venturi.
CI	compression-ignition.
CITT	Curb Idle Transmission Torque
CLD	chemiluminescent detector.
CVS	constant-volume sampler.
DF	deterioration factor.
ECM	electronic control module.
EFC	electronic flow control.
EGR	exhaust gas recirculation.
EPA	Environmental Protection Agency.
FEL	Family Emission Limit
FID	flame-ionization detector.
GC	gas chromatograph.
GC-ECD	gas chromatograph with an electron-capture detector.
IBP	initial boiling point.
ISO	International Organization for Standardization.
LPG	liquefied petroleum gas.
NDIR	nondispersive infrared.

NDUV	nondispersive ultraviolet.
NIST	National Institute for Standards and Technology.
PDP	positive-displacement pump.
PEMS	portable emission measurement system.
PFD	partial-flow dilution.
PMP	Polymethylpentene.
pt.	a single point at the mean value expected at the standard.
PTFE	polytetrafluoroethylene (commonly known as Teflon™).
RE	rounding error.
RMC	ramped-modal cycle.
RMS	root-mean square.
RTD	resistive temperature detector.
SSV	subsonic venturi.
SI	spark-ignition.
UCL	upper confidence limit.
UFM	ultrasonic flow meter.
U.S.C.	United States Code.