

standards from six different voluntary consensus standards bodies: ASTM, ASME, ISO, Gas Processors Association, American Gas Association, and American Petroleum Institute. These voluntary consensus standards will help facilities monitor, report, and keep records of greenhouse gas emissions. No new test methods were developed for this proposed rule. Instead, from existing rules for source categories and voluntary greenhouse gas programs, EPA identified existing means of monitoring, reporting, and keeping records of greenhouse gas emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including many for combustion sources such as methods to analyze fuel and measure its heating value; methods to measure gas or liquid flow; and methods to gauge and measure petroleum and petroleum products. The test methods are incorporated by reference into the proposed rule and are available as specified in proposed 40 CFR 98.7.

By incorporating voluntary consensus standards into this proposed rule, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for measuring greenhouse gas emissions.

EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

EO 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This proposed rule does not affect the level of protection provided to human health or the

environment because it is a rule addressing information collection and reporting procedures.

List of Subjects

40 CFR Part 86

Environmental protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements, Motor vehicle pollution.

40 CFR Part 87

Environmental protection, Air pollution control, Aircraft, Incorporation by reference.

40 CFR Part 89

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements, Research, Vessels, Warranty.

40 CFR Part 90

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Labeling, Reporting and recordkeeping requirements, Research, Warranty.

40 CFR Part 94

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Vessels, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Incorporation by reference, Suppliers, Reporting and recordkeeping requirements.

40 CFR Part 600

Administrative practice and procedure, Electric power, Fuel economy, Incorporation by reference, Labeling, Reporting and recordkeeping requirements.

40 CFR Part 1033

Environmental protection, Administrative practice and procedure, Confidential business information, Incorporation by reference, Labeling, Penalties, Railroads, Reporting and recordkeeping requirements.

40 CFR Part 1039

Environmental protection, Administrative practice and procedure,

Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 1042

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Vessels, Reporting and recordkeeping requirements, Warranties.

40 CFR Parts 1045, 1048, 1051, and 1054

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 1065

Environmental protection, Administrative practice and procedure, Incorporation by reference, Reporting and recordkeeping requirements, Research.

Dated: March 10, 2009.

Lisa P. Jackson,
Administrator.

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) Starting in the 2011 model year for heavy-duty engines, measure CO₂, N₂O, and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065. Report these values in your application for certification. 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 removing the paragraph (a) designation and adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§ 86.078–3 Abbreviations.

*	*	*	*	*
*	*	*	*	*
CH ₄ methane.				
*	*	*	*	*
N ₂ O nitrous oxide.				
*	*	*	*	*

Subpart B—[Amended]

4. A new § 86.165–11 is added to read as follows:

§ 86.165–11 Air Conditioning Idle Test Procedure.

(a) *Applicability.* This section describes procedures for determining air conditioning-related CO₂ emissions from 2012 and later model year light-duty vehicles, light-duty trucks, and medium-duty passenger vehicles.

(b) *Overview.* The test consists of a brief period to stabilize the vehicle at idle, followed by a ten-minute period of idle when CO₂ emissions are measured without any climate control systems operating; the test concludes with a ten-minute period when CO₂ emissions are measured with the air conditioning system operating. This test is designed to determine the air conditioning-related CO₂ emission value, in grams per minute per cubic foot of interior volume. If engine stalling occurs during cycle operation, follow the provisions of § 86.136–90 to restart the test. Measurement instruments must meet the specifications described in 40 CFR part 1065, subparts C and D.

(c) *Test sequence.* Before testing, precondition the vehicle as described in § 86.132, then allow the vehicle to idle for not less than 1 minute and not more than 5 minutes.

(1) Connect the vehicle exhaust system to the raw sampling location or dilution stage according to 40 CFR 1065.130. For dilution systems, dilute the exhaust as described in 40 CFR 1065.140. Continuous sampling systems must meet the specifications of 40 CFR 1065.145.

(2) Test the vehicle in a fully warmed-up condition. If the vehicle has soaked for two hours or less since the last exhaust test element, preconditioning may consist of a 505, 866, highway, US06, or SC03 test cycle. For longer soak periods, precondition the vehicle using one full Urban Dynamometer Driving Schedule.

(3) Immediately after the preconditioning described in paragraph (c)(1) of this section, turn off any cooling fans, if present, close the vehicle's hood, fully close all the vehicle's windows, ensure that all the vehicle's climate control systems are set to full off, start the CO₂ sampling system, and then idle the vehicle for not less than 1 minute and not more than 5 minutes to achieve normal and stable idle operation.

(4) Measure and record the continuous CO₂ concentration for 10.0 minutes. Measure the CO₂ concentration continuously using raw or dilute sampling procedures. Multiply this concentration by the continuous (raw or dilute) flow rate at the emission sampling location to determine the CO₂ flow rate. Calculate the constituent's cumulative flow rate continuously over the test interval. This cumulative value is the total mass of the emitted constituent.

(5) Within 60 seconds after completing the measurement described in paragraph (c)(4) of this section, turn on the vehicle's air conditioning system. Set automatic systems to a temperature 9 °F (5 °C) below the ambient temperature of the test cell. Set manual systems to maximum cooling with recirculation turned off. Continue idling the vehicle while measuring and recording the continuous CO₂ concentration for 10.0 minutes as described in paragraph (c)(4) of this section.

(d) *Calculations.* (1) For the measurement with no air conditioning, calculate the CO₂ emissions (in grams per minute) by dividing the total mass of CO₂ from paragraph (c)(4) of this section by 10.0.

(2) For the measurement with air conditioning in operation, calculate the CO₂ emissions (in grams per minute) by dividing the total mass of CO₂ from paragraph (c)(5) of this section by 10.0.

(3) Calculate the increased CO₂ emissions due to air conditioning (in grams per minute) by subtracting the results of paragraph (d)(1) of this section from the results of paragraph (d)(2) of this section.

(4) Divide the value from paragraph (d)(3) of this section by the interior volume of the vehicle to determine the increase in CO₂ emissions in grams per minute per cubic foot.

(e) *Reporting.* Include the value calculated in paragraph (d)(4) of this section in your application for certification.

Subpart E—[Amended]

5. Section 86.403–78 is amended by adding the abbreviations CH₄ and N₂O

in alphanumeric order to read as follows:

§ 86.403–78 Abbreviations.

*	*	*	*	*
*	*	*	*	*
CH ₄ methane.				
*	*	*	*	*
N ₂ O nitrous oxide.				
*	*	*	*	*

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

§ 86.431–78 Data submission.

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(e) Starting in the 2011 model year, measure CO₂, N₂O, and CH₄ 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 procedures specified in 40 CFR part 1065 as needed to measure N₂O, and CH₄. Report these values in your application for certification. Small-volume manufacturers (as defined in § 86.410–2006(e)) may omit this requirement. 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.

Subpart S—[Amended]

7. Section 86.1804–01 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§ 86.1804–01 Acronyms and abbreviations.

*	*	*	*	*
*	*	*	*	*
CH ₄ methane.				
*	*	*	*	*
N ₂ O nitrous oxide.				
*	*	*	*	*

8. Section 86.1843–01 is amended by adding paragraph (i) to read as follows:

§ 86.1843–01 General information requirements.

*	*	*	*	*
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(i) *Air conditioning leakage reporting.* Starting in the 2011 model year, the manufacturer shall calculate and report a value for the annual leakage of refrigerant emissions from the air conditioning system for each model type as described in 40 CFR 1064.201. The manufacturer shall also report the type of refrigerant and the refrigerant capacity for each air conditioning

system for each model type. The manufacturer shall calculate and report these items for each combination of vehicle model type (as defined in 40 CFR 600.002) and air conditioning system produced. However, calculation and reporting of these items for multiple air conditioning systems for a given model type is not necessary if air conditioning systems are identical with respect to the characteristics identified in paragraphs (i)(1) through (8) of this section and they meet the quantitative criteria identified in paragraph (i)(9) of this section. Consider all the following criteria to determine whether to calculate separate leakage rates for different air conditioning systems.

- (1) Compressor type (e.g., belt driven or electric).
- (2) Number and type of rigid pipes and method of connecting sections of rigid pipes.
- (3) Number and type of flexible hose and method of connecting sections of flexible hose. Consider two hoses to be of a different type if they use different materials or if they have a different configuration of layers for reducing permeation.

- (4) Number of high-side service ports.
- (5) Number of low-side service ports.
- (6) Number and type of switches, transducers, and expansion valves.
- (7) Number and type of refrigerant control devices.

(8) Number and type of heat exchangers, mufflers, receiver/driers, and accumulators.

(9) The following quantitative criteria (based on nominal values) define operating characteristics for including air conditioning systems together:

- (i) Refrigerant mass (rated capacity) of larger system divided by refrigerant mass of smaller system at or below 1.1.
- (ii) Total length of rigid pipe in the longer system divided by total length of rigid pipe in the shorter system at or below 1.1.
- (iii) Total length of flexible hose in the longer system divided by total length of flexible hose in the shorter system at or below 1.1.

9. Section 86.1844-01 is amended by adding paragraph (j) to read as follows:

§ 86.1844-01 Information requirements: Application for certification and submittal of information upon request.

* * * * *

(j) Starting in the 2011 model year, measure CO₂, N₂O, and CH₄ with each certification test on an emission data vehicle. Do not apply deterioration factors to the results. Use the procedures specified in 40 CFR part 1065 as needed to measure N₂O, and CH₄. Report these values in your application for

certification. Use the same measurement methods as for your other results to report a single value for CO₂, N₂O, and CH₄ for each test. Round the final values as follows:

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

PART 87—[AMENDED]

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

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

Subpart A—[Amended]

11. Section 87.2 is amended by adding the abbreviations CH₄ and CO₂ in alphanumeric order to read as follows:

§ 87.2 Acronyms and abbreviations.

* * * * *

CH₄ methane.

* * * * *

CO₂ carbon dioxide.

* * * * *

12. 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 in the 2011 model year, measure CH₄ with each certification test. Use good engineering judgment to determine CH₄ emissions using a nonmethane cutter or gas chromatograph as described in 40 CFR 1065.265 and 1065.267. Report CH₄ and CO₂ values along with your emission levels of regulated pollutants. Round the final values as follows:

- (1) Round CO₂ to the nearest 1 g/kilowatt rO.
- (2) Round CH₄ to the nearest 0.01g/g/kilowatt rO.

PART 89—[AMENDED]

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

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

Subpart A—[Amended]

14. Section 89.3 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§ 89.3 Acronyms and abbreviations.

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* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

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Subpart B—[Amended]

15. 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, N₂O, and CH₄ as specified in § 89.407(d)(1);

* * * * *

Subpart E—[Amended]

16. 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. Starting in the 2011 model year, also measure N₂O, and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers (as defined in 40 CFR 1039.801) may omit N₂O, and CH₄ measurements. 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:

- (i) Round CO₂ to the nearest 1 g/kW-hr.
- (ii) Round N₂O to the nearest 0.001 g/kW-hr.
- (iii) Round CH₄ to the nearest 0.001g/kW-hr.

* * * * *

PART 90—[AMENDED]

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

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

Subpart A—[Amended]

18. Section 90.5 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§ 90.5 Acronyms and abbreviations.

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* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

* * * * *

Subpart B—[Amended]

19. 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, N₂O, and CH₄ as specified in § 90.409(c)(1);

* * * * *

Subpart E—[Amended]

20. 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 NO_x concentrations in the exhaust sample. Starting in the 2011 model year, also measure N₂O, and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit N₂O, and CH₄ measurements. 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:

(i) Round CO₂ to the nearest 1 g/kW-hr.

(ii) Round N₂O to the nearest 0.001 g/kW-hr.

(iii) Round CH₄ to the nearest 0.001g/kW-hr.

* * * * *

PART 94—[AMENDED]

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

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

22. Section 94.3 is amended by adding the abbreviations CH₄ and N₂O in alphanumeric order to read as follows:

§ 94.3 Abbreviations.

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* * * * *

* * * * *

CH₄ methane.

* * * * *

N₂O nitrous oxide.

* * * * *

Subpart B—[Amended]

22. 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. Starting in the 2011 model year, measure CO₂, N₂O, and CH₄ as specified in 40 CFR 1042.235.

§ 94.109 [Amended]

23. Section 94.109 is amended by adding paragraph (d) to read as follows:

Subpart C—[Amended]

24. 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, N₂O, and CH₄ as specified in 40 CFR 89.407(d)(1) for Category 1 engines, § 94.104(e) for Category 2 engines, and § 94.109(d) for Category 3 engines. Small-volume manufacturers may omit the requirement to measure and report N₂O, and CH₄.

* * * * *

25. Add part 98 to read as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

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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) emissions reporting requirements for certain facilities that directly emit GHG as well as for fossil fuel suppliers and industrial GHG suppliers.

(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 Do I need to report?

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements, of this part apply to the owners and operators of any facility 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 of the source categories listed in this paragraph in any calendar year starting

in 2010. For these facilities, the GHG emission report must cover all sources in any source category for which calculation methodologies are provided in subparts B through JJ of this part.

(i) Electricity generating facilities that are subject to the Acid Rain Program, or that contain electric generating units that collectively emit 25,000 metric tons CO₂e or more per year.

(ii) Adipic acid production.
 (iii) Aluminum production.
 (iv) Ammonia manufacturing.
 (v) Cement production.
 (vi) Electronics—Semiconductor, microelectromechanical system (MEMS), and liquid crystal display (LCD) manufacturing facilities with an annual production capacity that exceeds any of the thresholds listed in this paragraph.

(A) Semiconductors: 1,080 m² silicon.
 (B) MEMS: 1,020 m² silicon.
 (C) LCD: 235,700 m² LCD.

(vii) Electric power systems that include electrical equipment with a total nameplate capacity that exceeds 17,820 lbs (7,838 kg) of SF₆ or perfluorocarbons (PFCs).

(viii) HCFC-22 production.
 (ix) 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.

(x) Lime manufacturing.
 (xi) Nitric acid production.
 (xii) Petrochemical production.
 (xiii) Petroleum refineries.
 (xiv) Phosphoric acid production.
 (xv) Silicon carbide production.
 (xvi) Soda ash production.
 (xvii) Titanium dioxide production.
 (xviii) Underground coal mines that are subject to quarterly or more frequent sampling by MSHA of ventilation systems.

(xix) Municipal landfills that generate CH₄ in amounts equivalent to 25,000 metric tons CO₂e or more per year.

(xx) Manure management systems that emit CH₄ and N₂O in amounts equivalent to 25,000 metric tons CO₂e or more per year.

(2) Any facility 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 (a)(2) and that are located at the facility in any calendar year starting in 2010. For these facilities, the GHG emission report must cover all source categories for which calculation methodologies are provided in subparts B through JJ of this part.

(i) Electricity generation.
 (ii) Electronics—photovoltaic manufacturing.

(iii) Ethanol production.
 (iv) Ferroalloy production.
 (v) Fluorinated greenhouse gas production.

(vi) Food processing.
 (vii) Glass production.
 (viii) Hydrogen production.
 (ix) Iron and steel production.
 (x) Lead production.
 (xi) Magnesium production.
 (xii) Oil and natural gas systems.
 (xiii) Pulp and Paper Manufacturing.
 (xiv) Zinc production.
 (xv) Industrial landfills.
 (xvi) Wastewater treatment.

(3) Any 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 GHG emission report must cover emissions from stationary fuel combustion sources only. For 2010 only, the facilities may submit an abbreviated emissions report according to § 98.3(d).

(i) The facility does not contain any source category designated in paragraphs (a)(1) and (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 from all stationary fuel combustion sources.

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

(i) Coal.
 (ii) Coal-based liquid fuels.
 (iii) Petroleum products.
 (iv) Natural gas and natural gas liquids.

(v) Industrial greenhouse gases, as specified in either paragraph (a)(4)(v)(A) or (B) of this section:

(A) All producers of industrial greenhouse gases.
 (B) Importers of industrial greenhouse gases with total bulk imports that exceed 25,000 metric tons CO₂e per year.

(C) Exporters of industrial greenhouse gases with total bulk exports that exceed 25,000 metric tons CO₂e per year.

(vi) Carbon dioxide, as specified in either paragraph (a)(4)(vi)(A) or (B) of this section.

(A) All producers of carbon dioxide.
 (B) Importers of CO₂ or a combination of CO₂ and other industrial GHGs with total bulk imports that exceed 25,000 metric tons CO₂e per year.

(C) Exporters of CO₂ or a combination of CO₂ and other industrial GHGs with

total bulk exports that exceed 25,000 metric tons CO₂e per year.

(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 (4) of this section.

(1) Estimate the annual emissions of CO₂, CH₄, N₂O, and fluorinated GHG (as defined in § 98.6) in metric tons from stationary fuel combustion units, miscellaneous uses of carbonate, and any applicable source category listed in paragraph § 98.2(a)(2). The GHG emissions shall be calculated using the methodologies specified in each applicable subpart. For this calculation, facilities with industrial landfills must use the CH₄ generation calculation methodology in subpart HH of this part.

(2) For stationary combustion units, calculate the annual CO₂ emissions in metric tons using any appropriate method specified in § 98.33(a). Calculate the annual CH₄ and N₂O emissions from the stationary combustion sources in metric tons using Equation C-9 in § 98.33(c). Carbon dioxide emissions from the combustion of biogenic fuels shall be excluded from the calculations. In using Equations C-2a and C-9 in § 98.33, the high heat value for all types of fuel shall be determined monthly.

(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), (2), and (3) of this section for each GHG and calculate metric tons of CO₂e using Equation A-1.

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

Where:

CO₂e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of each greenhouse gas emitted, 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, capture of CO₂ for transfer off site must not be considered.

(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, the owner or operator shall calculate CO₂,

CH₄, N₂O emissions from all stationary combustion units using 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 CO₂e per year threshold for importers and exporters of industrial greenhouse gases under paragraph (a)(4) of this section, the owner or operator shall calculate the total annual CO₂e of all the industrial GHGs that the company imported and the total annual CO₂e of all the industrial GHGs that the company exported during the reporting year, as described in paragraphs (d)(1) through (d)(3) of this section.

(1) Calculate the mass in metric tons per year of CO₂, N₂O, and each fluorinated GHG (as defined in § 98.6) imported and the mass in metric tons per year of CO₂, N₂O, and fluorinated GHG exported during the year. The masses shall be calculated using the methodologies specified in subpart OO of this part.

(2) Convert the mass of each GHG imported and each GHG exported from paragraph (d)(1) of this section to metric tons of CO₂e using Equation A-1 of § 98.3.

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

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

(f) Except as provided in paragraph (g) of this section, the owners and operators of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section are not required to submit an emission report for the facility or supplier. Such owners and operators must reevaluate the applicability to this part to the facility or supplier (which reevaluation must include the revising of any relevant emissions calculations or other calculations) whenever there is any change to the facility or supplier that could cause the 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.

(g) Once a facility or supplier is subject to the requirements of this part, the owners and operators of the facility or supply operation must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit GHG emission reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year. If a GHG emission source in a future year through change of ownership becomes part of a different facility that has not previously met, and does not in that future year meet, the applicability requirements of paragraph (a) of this section; the owner or operator shall comply with the requirements of this part only with regard to that source, including the requirement to submit GHG emission reports.

(h) 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 emissions reports to the Administrator, as specified in paragraphs (a) through (g) of this section.

(a) *General.* You must collect emissions data, calculate GHG emissions, and follow the procedures for quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) *Schedule.* Unless otherwise specified in subparts B through PP, you must submit an annual GHG emissions report no later than March 31 of each calendar year for GHG emissions in the previous calendar year.

(1) For existing facilities that commenced operation before January 1, 2010, you must report emissions for calendar year 2010 and each subsequent calendar year.

(2) For new facilities that commence operation on or after January 1, 2010, you must report emissions for the first calendar year in which the facility operates, 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, you must 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. 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 emissions report shall contain the following information:

(1) Facility name or supplier name (as appropriate), street address, physical address, and Federal Registry System identification number.

(2) Year covered by the report.

(3) Date of submittal.

(4) Annual emissions of CO₂, CH₄, N₂O, and each fluorinated GHG. Emissions must be calculated assuming no capture of CO₂ and reported at the following levels:

(i) Total facility emissions aggregated 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) Total emissions aggregated 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.

(iii) Emissions from each applicable source category or supply category in subparts C through PP of this part, expressed in metric tons of each GHG.

(iv) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in the "Data reporting requirements" section of each applicable subpart of this part.

(5) Total electricity generated onsite in kilowatt hours.

(6) Total pounds of synthetic fertilizer produced at the facility and total nitrogen contained in that fertilizer.

(7) Total annual mass of CO₂ captured in metric tons.

(8) 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) *Abbreviated emissions report.* 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 is subject to § 98.2(a)(3) may submit an abbreviated GHG emissions report for

the facility for emissions in 2010. The abbreviated report must be submitted by March 31, 2011. An owner or operator that submits an abbreviated report for a facility in 2011 must submit a full GHG emissions report according to the requirements of paragraph (c) of this section for each calendar year thereafter. The abbreviated facility report must include the following information:

(1) Facility name, street address, physical address, and Federal Registry System identification number.

(2) The year covered by the report.

(3) Date of submittal.

(4) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any appropriate method specified in § 98.33(a) and expressed in metric tons of CO₂, CH₄, N₂O, and CO₂e. If Equation C-2a or C-9 of subpart C are selected, the high heat value for all types of fuel shall be determined monthly.

(5) 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).

(e) *Emission Calculations.* In preparing the GHG emissions report, you must use the emissions calculation protocols specified in the relevant subparts, except as specified in paragraph (d) of this section.

(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)(5) of this section and any other credible evidence, in conjunction with a comprehensive review of the emissions 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 GHG emissions under this part must keep records as specified in this paragraph. You must retain all required records for at least 5 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 EPA, the records required under this section must be made available to the Administrator. 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. The results of all required fuel analyses for high heat value and carbon content, the results of all required certification and quality assurance tests of continuous monitoring systems and fuel flow meters if applicable, and analytical results for the development of site-specific emissions factors.

(3) Documentation of the process used to collect the necessary data for the GHG emissions calculations.

(4) The GHG emissions calculations and methods used.

(5) All emission factors used for the GHG emissions calculations.

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

(7) Names and documentation of key facility personnel involved in calculating and reporting the GHG emissions.

(8) The annual GHG emissions reports.

(9) A log book, documenting procedural changes (if any) to the GHG emissions accounting methods and changes (if any) to the instrumentation critical to GHG emissions calculations.

(10) Missing data computations.

(11) A written quality assurance performance plan (QAPP). Upon request from regulatory authorities, the owner or operator shall make all information that is collected in conformance with the QAPP available for review during an audit. Electronic storage of the information in the QAPP is permissible, provided that the information can be made available in hard copy upon request during an audit. At a minimum, the QAPP plan shall include (or refer to separate documents that contain) a detailed description of the procedures that are used for the following activities:

(i) Maintenance and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHG emissions reported under this part. A maintenance log shall be kept.

(ii) Calibrations and other quality assurance tests performed on the continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHG emissions reported under this part.

§ 98.4 Authorization and responsibilities of the designated representative.

(a) *General.* Except as provided under paragraph (f) of this section, each owner or operator that is subject to this part, shall have one and only one designated representative responsible for certifying and submitting GHG emissions reports and any other submissions to the Administrator under this part.

(b) *Authorization of a designated representative.* The designated representative of the facility shall be selected by an agreement binding on the owners and operators and shall act in accordance with the certification statements in paragraph (i)(4) of this section. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) *Responsibility of the designated representative.* Upon receipt by the Administrator of a complete certificate of representation under this section, the designated representative of the facility shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator 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 will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the owner or operator.

(e) *Certification of the GHG emissions report.* Each GHG emission report and any other submission under this part shall be submitted, signed, and certified by the designated representative in accordance with 40 CFR 3.10.

(1) Each such submission shall include the following certification statement by the designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate) 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 under this part only if the submission is signed and certified in accordance with paragraph (e)(1) of this section.

(f) *Alternate designated representative.* A certificate of representation under this section may designate an alternate designated representative, who may act on behalf of the designated representative. 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, 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, 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) may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under this section.

Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative (or alternate designated representative) before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(h) *Changes in owners and operators.* In the event a new owner or operator is not included in the list of owners and operators in the certificate of representation under this section, such new 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, as if the new owner or operator were included in such list. Within 30 days following any change in the owners and operators, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under this section amending the list of owners and operators to include the change.

(i) *Certificate of representation.* A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the facility or supply operation 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 supply operation.

(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 that are subject to the requirements of 40 CFR 98.3."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the Mandatory Greenhouse Gas Reporting Program on behalf of the owners and operators that are subject to the requirements of 40 CFR 98.3 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 that are subject to the requirements of 40 CFR 98.3 shall be bound by any order issued to me by the Administrator or a court regarding the source or unit."

(iv) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a facility (or supply operation as appropriate) that is subject to the requirements of 40 CFR 98.3, 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 that is subject to the requirements of 40 CFR 98.3.”

(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 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under this section 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 the Mandatory Greenhouse Gas Reporting Program.

(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.

§ 98.5 How do I submit my report?

Each GHG emissions report for a facility or supplier must be submitted electronically on behalf of the owners and operators of that facility or supplier by their designated representative, in a format specified by the Administrator.

§ 98.6 What definitions do I need to understand?

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

Abandoned (closed) mines mean mines that are no longer operational (per MSHA definition).

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

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

Acid gas means hydrogen sulfide (H₂S) and carbon dioxide (CO₂) contaminants that are separated from sour natural gas by an acid gas removal process.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents, such as liquid absorbents, solid adsorbents, or membrane separators.

Acid gas removal vent stack fugitive emissions mean the acid gas (typically CO₂ and H₂S) separated from the acid gas absorbing medium (most commonly an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

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.

Actual conditions mean temperature, pressure and volume at measurement conditions of natural gas.

Actuation means, for the purposes of this rule, an event in which a natural gas pneumatically driven valve is opened and/or closed by release of natural gas pressure to the atmosphere.

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

AGA means the American Gas Association

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high non-combustible component content).

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 equipment designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO₂ and CH₄, which is captured and flared or used as a fuel.

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.

Anti-static wrap means wrap used to assist the process of ensuring that all fugitive emissions from a single source are captured and directed to a measurement instrument.

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.

ASME means the American Society of Mechanical Engineers.

ASTM means the American Society of Testing and Materials.

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

Backpressure means impeding the natural atmospheric release of fugitive emissions by enclosing the release with a lower capacity sampling device and altering natural flow.

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.

Biodiesel means any liquid biofuel suitable as a diesel fuel substitute or a diesel fuel additive or extender. Biodiesel fuels are usually made from agricultural oils or from animal tallow.

Biogenic CO₂ means carbon dioxide emissions generated as the result of biomass combustion.

Biomass means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries 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.

Bleed rate means the rate at which natural gas flows continuously or intermittently from a process measurement instrument to a valve actuator controller where it is vented (bleeds) to the atmosphere.

Blendstocks are naphthas used for blending or compounding into finished motor gasoline. These include RBOB (reformulated gasoline for oxygenate blending), CBOB (conventional gasoline for oxygenate blending), and GTAB (gasoline treated as blendstock).

Blowdown means manual or automatic opening of valves to relieve pressure and or release natural gas from but not limited to process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance.

Blowdown vent stack fugitive emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and Emergency Shut-Down system testing.

Boil-off gas means natural gas that vaporizes from liquefied natural gas in storage tanks.

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, means the transfer of a product inside containers, including but not limited to tanks, cylinders, drums, and pressure vessels.

Butane (C₄H₁₀) or n-Butane means the normally gaseous straight-chain or branch-chain hydrocarbon extracted from natural gas or refinery gas streams and is designated in ASTM Specification D1835 and Gas Processors Association Specifications for commercial butane. Not included in this definition is isobutene, which normally is used for feedstock.

Butylene (C₂H₄) is an olefinic hydrocarbon recovered from refinery processes and used as a feedstock.

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.

By-product formation is the quantity of fluorinated GHGs created during the etching or chamber cleaning processes in an electronics manufacturing process.

C2+ means the NGL fraction consisting of hydrocarbon molecules

ethane and heavier. The characteristics for this fraction, as reported in Table MM-2, are derived from the mixture of 31 percent ethane and 29 percent propane as reported in Table MM-1, and 41 percent C4+. These proportions are determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100 °F and pressure of 40 psig.

C4+ means the NGL fraction consisting of hydrocarbon molecules butane and heavier. The characteristics for this fraction, as reported in Table MM-2, are derived from the mixture of 39 percent "pentanes plus" and 61 percent butane as reported in Table MM-1. These proportions are determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100 °F and pressure of 40 psig.

C5+ is pentane plus in the specific chemical composition that underlies the default factors in Table MM-1.

C6+ means NGL fraction consisting of hydrocarbon molecules hexane and heavier. The characteristics for this fraction, as reported in Table MM-2, are derived from the assumption that "pentane plus", as reported in Table MM-1, consists of a mixture of 53 percent C6+ and 47 percent pentane. These proportions are determined from an example API E&PTankCalc run on 34°API crude oil from a separator temperature of 100 °F and pressure of 40 psig.

Calibrated bag means a flexible, non-elastic bag of a calibrated volume that can be quickly affixed to a fugitive emitting source such that the fugitive emissions inflate the bag to its calibrated volume.

Carbon black oil means a heavy aromatic oil that may be derived either as a by-product of petroleum refining or metallurgical coke production. Carbon black oil consists mainly of unsaturated hydrocarbons, predominately higher than C14.

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 primary greenhouse gas.

Carbon dioxide production well means any hole drilled in the earth to extract a carbon dioxide stream 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.

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 weight percentage of carbon 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 (MgCO₃) or magnesite; and calcium-magnesium carbonate (CaMg(CO₃)₂) or dolomite.

Carbonate-based mineral means any of the following minerals used in the manufacture of glass: calcium carbonate (CaCO₃), calcium magnesium carbonate (CaMg(CO₃)₂), and sodium carbonate (Na₂CO₃).

Carbonate-based mineral mass fraction means the following: for limestone, the mass fraction of CaCO₃ in the limestone; for dolomite, the mass fraction of CaMg(CO₃)₂ in the dolomite; and for soda ash, the mass fraction of Na₂CO₃ 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.

Carrier gas means the gas with which cover gas is mixed to transport and dilute the cover gas thus maximizing its efficient use. Carrier gases typically include CO₂, N₂, and/or dry air.

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.

Cattle and swine deep bedding means 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 or conventional gasoline for oxygenate blending means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional gasoline.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings that are located around the compressor shaft where it exits the compressor case and that operate mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor dry seals fugitive emissions mean natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seals mean a series of rings around the compressor shaft where it exits the compressor case, that use oil circulated under high pressure between the rings to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor wet seals fugitive emissions mean natural gas released from the seal face around the rotating shaft where it exits one or both ends of the compressor case PLUS the natural gas absorbed in the circulating seal oil and vented to the atmosphere from a seal oil degassing vessel or sump before the oil is re-circulated, or from a seal oil containment vessel vent.

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.

Close-range means, for the purposes of this rule, safely accessible within the operator's arm's reach from the ground or stationary platforms.

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" (as incorporated by reference in § 98.7).

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

Coke (petroleum) means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

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.

Cold and steady emissions mean a nearly constant and steady emissions stream that is low enough in temperature (i.e., less than 140 degrees Fahrenheit) to be safely directly measured by a person.

Commercial Applications means any use including but not limited to: Food and beverage, industrial and municipal water/wastewater treatment, metal fabrication, including welding and cutting, greenhouse uses for plant growth, fumigants (e.g., grain storage) and herbicides, pulp and paper, cleaning and solvent use, fire fighting, transportation and storage of explosives, enhanced oil and natural gas recovery, long-term storage (sequestration), or research and development.

Completely destroyed means destroyed with a destruction efficiency of 99.99 percent or greater.

Completely recaptured means 99.99 percent or greater of each GHG is removed from a process stream.

Component, for the purposes of subpart W only, means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas (i.e., compression ratio higher than 1.5).

Compressor fugitive emissions mean natural gas emissions from all components in close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates, including but not limited to open-ended blowdown vent stacks, piping and tubing connectors and flanges, pressure relief valves, pneumatic starter open-ended lines, instrument connections, cylinder valve covers, and fuel valves.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

Connector means but is not limited 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 regulation.

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.

Control method means any equipment used for recovering and/or oxidizing air emissions of methane. Such equipment includes, but is not limited to, vapor recovery systems, absorbers, carbon dioxide adsorbers, condensers, incinerators, flares, catalytic oxidizers, boilers, and process heaters.

Conventional gasoline means any gasoline which has not been certified under § 80.40.

Cover gas means SF₆, HFC-134a, fluorinated ketone (FK 5-1-12) or other gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air. The molten magnesium may be the surface of a casting or ingot production operation or the surface of a crucible of molten magnesium that is the source of the casting operation.

Crude oil means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chains and rings.

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

Degasification systems mean wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH₄ before, during, or after mining. Pre-mining degasification systems refer to drainage wells drilled through a coal seam or seams and cased to pre-drain the methane prior to mining. The wells are normally placed in operation 2 to 7 years ahead of mining. Degasification systems also include "gob wells" which recover methane from the longwall face area during and after mining.

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

Dehydrator means, for the purposes of this rule, a device in which a liquid absorbent (including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent stack fugitive emissions means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

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.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (ethane, propane, butane, pentane-plus) in feed natural gas stream.

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

Destruction means, with respect to underground coal mines, 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 the following Equation A-2:

$$DE = 1 - \frac{tCO_{2eOUT}}{tCO_{2eIN}} \quad (\text{Eq. A-2})$$

Where:

DE = Destruction Efficiency
 tCO_{2eIN} = The GWP-weighted mass of GHGs fed into the destruction device
 tCO_{2eOUT} = 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

Destruction or removal efficiency (DRE) is the efficiency of a control device to destroy or remove F-GHG and N₂O. The DRE is equal to one minus the ratio of the mass of all relevant GHG exiting the emission control device to the mass of GHG entering the emission control device.

Diesel fuel means a low sulfur fuel oil of grades 1BD or 2BD, as defined by the American Society for Testing and Materials standard ASTM D975-91, "Standard Specification for Diesel Fuel Oils" (as incorporated by reference in § 98.7), grades 1-GT or 2-GT, as defined by ASTM D2880-90a, "Standard Specification for Gas Turbine Fuel Oils" (as incorporated by reference in § 98.7), or fuel oil numbers 1 or 2, as defined by ASTM D396-90a, "Standard Specification for Fuel Oils" (as incorporated by reference in § 98.7).

Diesel fuel No. 1 has a distillation temperature of 550 °F at the 90 percent recovery point and conforms to ASTM D975-08 (2007) Standard Specification for Diesel Fuel Oils. It is used in high speed diesel engines such as city buses. Compared to fuel oil No. 1 it has a higher octane number, a lower sulfur content, and a higher flash point. It is blended with diesel No. 2 in the colder regions of the country to facility cold starts.

Diesel fuel No. 2 has a distillation temperature of 500 °F at the 10 percent recovery point and 640 °F at the 90 percent recovery point and is defined in ASTM D975. It is used in high speed diesel engines, such as locomotives, trucks and automobiles. Currently, there are three categories of diesel fuel No. 2 defined by sulfur content: High sulfur (>0.05%/wgt), low sulfur (<0.05%/wgt), and ultra low sulfur (<0.0015%/wgt). Ultra low sulfur is used for on road vehicles.

Diesel fuel No. 4, made by blending diesel fuel and residual fuel and conforming to ASTM D975, is used for low and medium speed diesel engines.

Digesters are systems where animal excreta are collected and anaerobically digested in a large containment vessel or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO₂ and CH₄, which is captured and may be flared or used as fuel. There are multiple types of anaerobic digestion systems, including covered lagoon, complete mix, plug flow, and fixed film digesters.

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 both diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4) and fuel oils (Fuel oil No. 1, No. 2, and No. 4). Fuel oils are used primarily for space heating, in industrial and commercial boilers and furnaces and for electric power generation. Diesel fuels are used in on-highway vehicles as well as in off highway engines, such as locomotives, marine engines, agricultural and construction equipment.

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

Dry lot means 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.

Electrical equipment means any item used for the generation, conversion, transmission, distribution or utilization of electric energy, such as machines, transformers, apparatus, measuring instruments, or protective devices, that contains sulfur hexafluoride (SF₆) or perfluorocarbons (PFCs) (including but not limited to gas-insulated switchgear substations (GIS), gas circuit breakers (GCB), and power transformers).

Electricity generating unit or EGU means any unit that combusts solid, liquid, or gaseous fuel and is physically connected to a generator to produce electricity.

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

Emergency generator means a stationary internal combustion engine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. Emergency engines operate only during emergency situations or for standard performance testing procedures as required by law or by the engine manufacturer. The hours of operation per calendar year for such standard performance testing shall not exceed 100 hours. An engine that serves as a back-up power source under

conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency engine.

Engineering estimation means an estimate of fugitive emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Equipment means but is not limited to each pump, compressor, pipe, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, tank, vessel, and instrumentation system in natural gas or liquid service; and any control devices or systems referenced by this subpart.

Equipment chambers means the total natural gas-containing volume within any equipment and between the equipment isolation valves.

Ethane (C₂H₆) is a colorless paraffinic gas that boils at temperatures of -127.48 °F. It is extracted from natural gas and from refinery gas streams. Ethane is a major feedstock for the petrochemical industry.

Ethylene (C₂H₄) is an olefinic hydrocarbon received from refinery processes or petrochemical processes. Ethylene is used as a petrochemical feedstock for numerous chemical applications and the production of consumer goods.

Ex refinery gate means the point at which a refined or semi-refined 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 United States military bases and ships for on-board use.

Exporter means any person, company, or organization of record that contracts to transfer a product from the United States to another country or that transfers products to an affiliate in another country, excluding transfers to United States military bases and ships for on-board use.

Extracted means production of carbon dioxide from carbon dioxide production wells.

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.

Finished 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 (2002) and Military Specification MIL-G-5572.

Finished motor gasoline means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline, defined in ASTM Specifications D4814-08a (2001) or Federal Specification VV-G-1690C, has a boiling range of 122 ° to 158 °F at the 10 percent recovery point to 365 ° to 374 °F at the 90 percent recovery rate. 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.

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.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip, assumed 95 percent for non-aspirated field flares and 98 percent for steam or air asperated flares.

Flare stack means a device used to provide a safe means of combustible natural gas disposal from routine operations, upsets, or emergencies via combustion of the natural gas in an open, normally elevated flame.

Flare stack fugitive emissions means the CH₄ and CO₂ content of that portion of natural gas (typically 5 percent in non-aspirated field flares and 2 percent in steam or air asperated flares) that passes through flares un-combusted and the total CO₂ emissions of that portion of the natural gas that is combusted.

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

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 (SF₆), nitrogen trifluoride (NF₃), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82 Subpart A. In addition to SF₆ and NF₃, "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 for purpose of creating useful heat.

Fuel means solid, liquid or gaseous combustible material.

Fuel ethanol (C₂H₅OH) is an anhydrous alcohol made either chemically from ethylene or biologically from the fermentation of sugars from carbohydrates found in agricultural products. It is used as a gasoline octane enhancer and as an oxygenate blendstock.

Fuel gas (still 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.

Fuel oil No. 1 has a distillation temperature of 400 °F at the 10 percent recovery point and 550 °F at the 90 percent recovery point and is used primarily as fuel for portable outdoor stoves and heaters. It is defined in ASTM D396-08 (2007) Standard Specification for Fuel Oils.

Fuel oil No. 2 has a distillation temperature of 400 °F at the 10 percent recovery point and 640 °F at the 90 percent recovery point and is defined in ASTM D396. It is used primarily for residential heating and for moderate capacity commercial and industrial burner units.

Fuel oil No. 4 is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil and conforms to ASTM D396 or Federal Specification VV-F-815C, and is used extensively in industrial plants and commercial burner installations that are not equipped with preheating facilities.

Fugitive emissions means unintentional equipment emissions of methane and/or carbon dioxide containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. Fugitive emissions also mean CO₂ emissions resulting from combustion of natural gas in flares.

Fugitive emissions detection means the process of identifying emissions from equipment, components, and other point sources.

Fugitive emissions detection instruments mean any device or

instrument that has been approved for fugitive emissions detection in this rule, namely infrared fugitive emissions detection instruments, OVAs, and TVAs.

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 conditions mean the actual temperature, volume, and pressure of a gas sample.

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.

Gas utilization is the quantity of GHG gas consumed (and therefore not available for emission) during the etching and/or chamber cleaning processes.

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 material into a gas.

Gathering and boosting station means a station used to gather natural gas from well or field pipelines for delivery to a natural gas processing facility or central point. Stations may also provide compression, dehydration, and/or treating services.

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.

Global warming potential or GWP means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram (kg) of a trace substance relative to that of one kg 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), chlorofluorocarbons (CFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

Heat Transfer Fluids are F-GHG that are liquid at room temperature, have appreciable vapor pressures, and are used for temperature control during certain processes in electronic manufacturing. Heat transfer fluids used in the electronics sector include perfluoropolyethers, perfluoroalkanes, perfluoroethers, tertiary perfluoroamines, and perfluorocyclic ethers.

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.

High volume sampler means an atmospheric emissions measurement device that captures emissions from a source in a calibrated air intake and uses dual hydrocarbon sensors and other devices to measure the flow rate and combustible hydrocarbon concentrations of the fugitive emission such that the quantity of emissions is determined.

Hydrofluorocarbons or HFCs means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

Import means, with respect to fluorinated GHGs and nitrous oxide, 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, and
- (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.

Importer means any person, company, or organization of record that for any reason brings a product into the United States from a foreign country. An importer includes 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 also 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.

Infrared remote fugitive emissions detection instrument means an instrument that detects infrared light in the narrow wavelength range absorbed by light hydrocarbons including methane, and presents a signal (sound, digital or visual image) indicating the presence of methane and other light hydrocarbon vapor emissions in the atmosphere. For the purpose of this rule, it must detect the presence of methane.

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.

Integrated process means a process that produces a petrochemical as well as one or more other chemicals that are part of other source categories under this part. An example of an integrated process is the production of both hydrogen for sale (i.e., a merchant hydrogen facility) and methanol from synthesis gas created by steam reforming of methane.

Interstate pipeline means a natural gas pipeline designated as interstate pipelines under the Natural Gas Act, 15 U.S.C. 717a.

Intrastate pipeline means a natural gas pipeline not subject to the jurisdiction of the Federal Energy Regulatory Commission as described in 15 U.S.C. 3301.

Isobutane (C₄H₁₀) is a normally gaseous branch chain hydrocarbon extracted from natural gas or refinery gas streams. A colorless paraffinic gas that boils at 10.9 °F, it is used as a feedstock in refineries.

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. It meets ASTM Specification D1655-08a (2001) and Military Specification MIL-T-5624P and MIL-T-83133D (JP-5 and JP-8).

Kiln means a device, including any associated preheater or precalciner devices, that produces clinker by heating limestone and other materials for subsequent production of portland cement.

Kiln exhaust gas bypass means alkali bypass.

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 § 257.2 of this chapter.

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.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

Liquefied natural gas import and export facilities mean onshore and/or offshore facilities that send out exported or receive imported liquefied natural gas, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to natural gas transmission or distribution systems. The facilities include tanker unloading equipment, liquefied natural gas transportation pipelines, pumps, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

Liquefied natural gas storage facilities means an onshore facility that stores liquefied natural gas in above ground storage vessels. The facility may include equipment for liquefying natural gas, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

Liquid/Slurry means 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.

LNG import and export facility fugitive emissions mean natural gas releases from valves, connectors, storage tanks, flanges, open-ended lines, pressure relief valves, boil-off-gas recovery, send outs (pumps and vaporizers), packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

LNG storage station fugitive emissions mean natural gas releases from valves, connectors, flanges, open-ended lines, storage tanks, pressure relief valves, liquefaction process units, packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

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.

Mass-balance approach means a method for estimating emissions of fluorinated greenhouse gases from use in equipment that can be applied to aggregates of units (for example by system). In this approach, annual emissions are the difference between the quantity of gas consumed in the year and the quantity of gas used to fill the net increase in equipment capacity or to replace destroyed gas.

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 amount of municipal solid waste per day (in tons/day) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Mcf means thousand cubic feet.

Meter means a device that measures gas flow rate from a fugitive emissions source or through a conduit by detecting a condition (pressure drop, spin induction, temperature loss, electronic signal) that varies in proportion to flow rate or measures gas velocity in a manner that can calculate flow rate.

Methane conversion factor means the extent to which the CH₄ producing capacity (B_o) 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.

Miscellaneous products include all petroleum products not classified elsewhere. It includes petrolatum lube refining by-products (aromatic extracts and tars) absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils.

MMBtu means million British thermal units.

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 (§ 257.2 of this chapter) 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. 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.

NAESB is the North American Energy Standards Board.

Nameplate capacity means the full and proper charge of gas specified by the equipment manufacturer to achieve the equipment's specified performance. The nameplate capacity is typically indicated on the equipment's nameplate; it is not necessarily the actual charge, which may be influenced by leakage and other emissions.

Naphtha-type jet fuel means a fuel in the heavy naphtha boiling range having an average gravity of 52.8 API and meeting Military Specification MIL-T-5624L (Grade JP-4). It is used primarily for military turbojet and turboprop aircraft because it has a lower freeze point than other aviation fuels and meets engine requirements at high altitudes and speeds.

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 driven pneumatic manual valve actuator device means valve control devices that use pressurized natural gas to provide the energy required for an operator to manually open, close, or throttle a liquid or gas stream. Typical manual control applications include, but are not limited to, equipment isolation valves, tank drain valves, pipeline valves.

Natural gas driven pneumatic manual valve actuator device fugitive emissions means natural gas released due to manual actuation of natural gas pneumatic valve actuation devices, including, but not limited to, natural gas diaphragm and pneumatic-hydraulic valve actuators.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Natural gas driven pneumatic pump fugitive emissions means natural gas released from pumps that are powered or assisted by pressurized natural gas.

Natural gas driven pneumatic valve bleed device means valve control devices that use pressurized natural gas to transmit a process measurement signal to a valve actuator to automatically control the valve opening. Typical bleeding process control applications include, but are not limited to, pressure, temperature, liquid level, and flow rate regulation.

Natural gas driven pneumatic valve bleed devices fugitive emissions means the continuous or intermittent release of natural gas from automatic process control loops including the natural gas pressure signal flowing from a process measurement instrument (e.g. liquid level, pressure, temperature) to a process control instrument which activates a process control valve actuator.

Natural gas liquids (NGL) means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods in gas processing or cycling

plants. Generally, such liquids consist of primarily ethane, propane, butane, and isobutane, primarily pentanes produced from natural gas at lease separators and field facilities. For the purposes of subpart NN only, natural gas liquids does not include lease condensate. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

Natural gas processing facilities are engaged in the extraction of natural gas liquids from produced natural gas; fractionation of mixed natural gas liquids to natural gas products; and removal of carbon dioxide, sulfur compounds, nitrogen, helium, water, and other contaminants. Natural gas processing facilities also encompass gathering and boosting stations that include equipment to phase-separate natural gas liquids from natural gas, dehydrate the natural gas, and transport the natural gas to transmission pipelines or to a processing facility.

Natural gas products means products produced for consumers from natural gas processing facilities including, but not limited to, ethane, propane, butane, iso-butane, and pentanes-plus.

Natural gas transmission compression facility means any permanent combination of compressors that move natural gas at increased pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage facilities. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and storage of water and hydrocarbon liquids.

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 natural gas liquids, hydrogen and other hydrocarbons, and petroleum products that are input into the atmospheric distillation column or other processing units in a refinery

Non-pneumatic pump means any pump that is not pneumatically powered with pressurized gas of any type, such as natural gas, air, or nitrogen.

Non-pneumatic pump fugitive emissions means natural gas released through connectors and flanges of electric motor or engine driven pumps.

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.

Non-steam aspirated flare means a flare where natural gas burns at the tip with natural induction of air (and relatively lower combustion efficiency as may be evidenced by smoke formation).

Offshore means tidal-affected borders of the U.S. lands, both state and Federal, adjacent to oceans, bays, lakes or other normally standing water.

Offshore petroleum and natural gas production facilities means any platform structure, floating in the ocean or lake, fixed on ocean or lake bed, or located on artificial islands in the ocean or lake, that houses equipment to extract hydrocarbons from ocean floor and transports it to storage or transport vessels or onshore. In addition, offshore production facilities may include equipment for separation of liquids from natural gas components, dehydration of natural gas, extraction of H₂S and CO₂ from natural gas, crude oil and condensate storage tanks, both on the platform structure and floating storage tanks connected to the platform structure by a pipeline, and compression or pumping of hydrocarbons to vessels or onshore. The facilities under consideration are located in both State administered waters and Mineral Management Services administered Federal waters.

Offshore platform pipeline fugitive emissions means natural gas above the water line released from piping connectors, pipe wall ruptures and holes in natural gas and crude oil pipeline surfaces on offshore production facilities.

Oil/water separator means equipment used to routinely handle oily-water streams, including gravity separators or ponds and air flotation systems.

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 line fugitive emissions means natural gas released from pipes or valves open on one end to the atmosphere that are intended to periodically vent or drain natural gas to the atmosphere but may also leak process gas or liquid through incomplete valve closure including valve seat obstructions or damage.

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.

Operating pressure means the containment pressure that characterizes the normal state of gas and/or liquid inside a particular process, pipeline, vessel or tank.

Operator means any person who operates or supervises a facility or supply operation.

Organic monitoring device means an instrument used to indicate the concentration level of organic compounds exiting a control device based on a detection principle such as IR, photoionization, or thermal conductivity.

Organic vapor analyzer (OVA) means an organic monitoring device that uses a flame ionization detector to measure the concentrations in air of combustible organic vapors from 9 to 10,000 parts per million sucked into the probe.

Owner means any person who has legal or equitable title to, has a leasehold interest in, or control of a facility or supply operation.

Oxygenated gasoline means gasoline which contains a measurable amount of oxygenate.

Oxygenates means substances which, when added to gasoline increase the oxygen content of the gasoline. Common oxygenates are ethanol CH₃-CH₂OH, Methyl Tertiary Butyl Ether (CH₃)₃COCH₃ (MTBE), Ethyl Tertiary Butyl Ether (CH₃)₃COC₂H (ETBE), Tertiary Amyl Methyl Ether (CH₃)(C₂H₅) COCH₃ (TAME), Diisopropyl Ether (CH₃)₂CHOCH(CH₃)₂ (DIPE), and Methanol CH₃OH. Lawful use of any of the substances or any combination of these substances requires that they be "substantially similar" under section 211(f)(1) of the Clean Air Act.

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

Pentanes plus is a mixture of hydrocarbons, mostly pentanes and heavier, extracted from natural gas. Pentanes plus includes isopentane, 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 naphtha 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) and has low ash content. It is used as a feedstock in coke ovens for the steel industry, for heating purposes, for electrode manufacture and for production of chemicals.

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. 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 asphalt and road oil, lubricants, waxes, plastics, and plastics products.

Platform fugitive emissions means natural gas released from equipment and equipment components including valves, pressure relief valves, connectors, tube fittings, open-ended lines, ports, and hatches. This does not include fugitive emissions from equipment and components reported elsewhere for this rule.

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:

(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.

Post-coal mining activities means the storage, processing, and transport of extracted coal.

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

Poultry manure without litter systems 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) means that 95 percent of repeat measurements made by a device or technique fall within the range bounded by the mean of the measurements plus or minus the specified level.

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 includes, but is 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.

Primary product means the product of a process that is produced in greater mass quantity than any other product of the process.

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 Type, for purposes of electronics manufacturing, means the

kind of electronics manufacturing process, i.e., etching, cleaning, or chemical vapor deposition using N₂O.

Process gas means any gas generated by an industrial process such as petroleum refining.

Processing facility fugitive emissions means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system fugitive emissions, packing and gaskets in natural gas processing facilities. This does not include fugitive emissions from equipment and components reported elsewhere for this rule, such as compressor fugitive emissions; acid gas removal, blowdown, wet seal oil degassing, and dehydrator vents; and flare stacks.

Production process unit means equipment used to capture a carbon dioxide stream.

Propane means the normally gaseous paraffinic compound (C₃H₈), which includes all products covered by Natural Gas Policy Act Specifications for commercial and HD-5 propane and ASTM Specification D 1835. It excludes feedstock propanes, which are propanes not classified as consumer grade propanes, including the propane portion of any natural gas liquid mixes, i.e., butane-propane mix.

Propylene (C₃H₆) is an olefinic hydrocarbon recovered from refinery processes or petrochemical processes.

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.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal fugitive emissions means natural gas released from the seal face between the pump internal chamber and the atmosphere.

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

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reciprocating compressor rod packing fugitive emissions means natural gas released from a connected tubing vent and/or around a piston rod where it passes through the rod packing case. It also includes emissions from uncovered distance piece, rod packing flange (on each cylinder), any packing vents, cover plates (on each cylinder), and the crankcase breather cap.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Refined petroleum product means petroleum products produced from the processing of crude oil, lease condensate, natural gas and other hydrocarbon compounds

Refinery fuel gas (still gas) means any gas generated at a petroleum refinery, or any gas generated by a refinery process unit, that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

Reformulated gasoline means any gasoline whose formulation has been certified under 40 CFR 80.40, and which meets each of the standards and requirements prescribed under 40 CFR 80.41.

Re-gasification means the process of vaporizing liquefied natural gas to gaseous phase natural gas.

Research and development process unit means a process unit whose purpose is to conduct research and development for new processes and products and is not engaged in the manufacture of products for commercial sale, except in a *de minimis* manner.

Residual fuel oil means a classification for the heavier fuel oils, No. 5 and No. 6. No. 5 is also known as Navy Special and is used in steam powered vessels in government service and inshore power plants. No.6 includes

Bunker C and is used for the production of electric power, space heating, vessel bunkering and various industrial purposes.

Residue gas means natural gas from which natural gas processing facilities liquid products and, in some cases, non-hydrocarbon components have been extracted.

Rotameter means a flow meter in which gas flow rate upward through a tapered tube lifts a "float bob" to an elevation related to the gas flow rate indicated by etched calibrations on the wall of the tapered tube.

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

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.

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.

Simulation software means a calibrated, empirical computer program that uses physical parameters and scientific laws to numerically simulate the performance variables of a physical process, outputting such parameters as emission rates from which methane emissions can be estimated.

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 natural gas means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Special naphthas means all finished products with the naphtha boiling range (290° to 470 °F) that are used as paint thinners, cleaners or solvents.

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 60 degrees Fahrenheit and 14.7 pounds per square inch absolute.

Standby means for an equipment to be in a state ready for operation, but not operating.

Steam aspirated flare means steam injected into the flare burner tip to induce air mixing with the hydrocarbon fuel to promote more complete combustion as indicated by lack of smoke formation.

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.

Storage station fugitive emissions means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system emissions, packing and gaskets in natural gas storage station. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

Storage tank means other vessel 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.

Storage tank fugitive emissions means natural gas vented when it flashes out of liquids; this occurs when liquids are transferred from higher pressure and temperature conditions upstream, plus working losses from liquid level increases and decreases during filling and draining and standing losses (breathing losses) from diurnal temperature changes and barometric pressure changes expanding and contracting the vapor volume of a tank.

Storage wellhead fugitive emissions means natural gas released from storage station wellhead components including but not limited to valves, OELs, connectors, flanges, and tube fittings.

Sub-surface or subsurface facility means for the purposes of this rule, a natural gas facility, such as a pipeline and metering and regulation station in a closed vault below the land surface of the Earth.

Sulfur recovery plant means all process units which recover sulfur or produce sulfuric acid from hydrogen sulfide (H₂S) and/or sulfur dioxide (SO₂) 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 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.

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.

Tanker unloading means pumping of liquid hydrocarbon (e.g., crude oil, LNG) from an ocean-going tanker or barge to shore storage tanks.

Toxic vapor analyzer (TVA) means an organic monitoring device that uses a flame ionization detector and photoionization detector to measure the

concentrations in air of combustible organic vapors from 9 parts per million and exceeding 10,000 parts per million sucked into the probe.

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

Trained technician means a person who has completed a vendor provided or equivalent training program and demonstrated proficiency to use specific equipment for its intended purpose, such as high volume sampler for the purposes of this rule.

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.

Transmission compressor station fugitive emissions means natural gas released from all components including but not limited to valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system emissions, packing and gaskets in natural gas transmission compressor stations. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule, such as compressor fugitive emissions.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Trona means the raw material (mineral) used to manufacture soda ash; hydrated sodium bicarbonate carbonate (NaCO₃.NaHCO₃.2H₂O).

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

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.

Uncovered anaerobic lagoons are a type of liquid storage system designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields.

Underground natural gas storage facility means a subsurface facility, including but not limited to depleted gas or oil reservoirs and salt dome caverns, utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at a natural gas underground storage facility include, but are not limited to, compression, dehydration and flow measurement. The storage facility also includes all the wellheads connected to the compression units located at the facility.

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 subpart, 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.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize liquefied natural gas to supply transmission and distribution pipelines, or consumers with natural gas.

Ventilation system means a system deployed within a mine to ensure that CH₄ levels remain within safe concentrations.

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).

Waste feedstocks are non-crude feedstocks that have been contaminated, downgraded, or no longer meet the specifications of the product category or end-use for which they were intended. Waste feedstocks include but are not limited to: Used plastics, used engine oils, used dry cleaning solvents, and trans-mix (mix of products at the interface in delivery pipelines).

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.

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

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

You means the 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 for use in this part and are incorporated as they existed on the date of approval of this part.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(1) ASTM D240-02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.

(2) ASTM D388-05, Standard Classification of Coals by Rank.

(3) ASTM D396-08, Standard Specification for Fuel Oils.

(4) ASTM D975-08, Standard Specification for Diesel Fuel Oils.

(5) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables.

(6) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.

(7) ASTM Specification D1835-05 (2005).

(8) ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

(9) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

(10) ASTM D2013-07, Standard Practice of Preparing Coal Samples for Analysis.

(11) ASTM D2234/D2234M-07, Standard Practice for Collection of a Gross Sample of Coal.

(12) ASTM D2502-04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.

(13) ASTM D2503-92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

(14) ASTM D2880-03, Standard Specification for Gas Turbine Fuel Oils.

(15) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(16) 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.

(17) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.

(18) ASTM Specification D3699-07, Standard Specification for Kerosene.

(19) ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(20) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).

(21) ASTM Specification D4814-08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.

(22) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.

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

(24) ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.

(25) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke.

(26) ASTM D6316-04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.

(27) ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.

(28) ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.

(29) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

(30) ASTM CS-104 (1985), Carbon Steel of Medium Carbon Content.

(31) ASTM D 7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.

(32) ASTM D6060-96(2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.

(33) ASTM D 2502-88(2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.

(34) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime.

(35) UOP539-97 Refinery Gas Analysis by Gas Chromatography.

(b) The following materials are available for purchase from the American Society of Mechanical

Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007–2900:

(1) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.

(2) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.

(3) ASME-MFC–5M–1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.

(4) ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.

(5) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.

(6) ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank.

(2) 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).

(3) 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).

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(1) GPA Standard 2172–96, Calculation of Gross Heating Value,

Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.

(2) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street, NW., Washington, DC 20005–4070:

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3—Tank Gauging:

(i) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(ii) Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(iii) Section 3—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems:

(i) Section 2—Displacement Provers, Third Edition, September 2003.

(ii) Section 5—Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(g) The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle, NE., Atlanta, Georgia 30329.

(1) ASHRAE 41.8–1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

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

Any violation of the requirements of this part shall be a violation of the Clean Air Act. 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 emission, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.

TABLE A–1 OF SUBPART A—GLOBAL WARMING POTENTIALS (100-YEAR TIME HORIZON)

Name	CAS No.	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 CHFCF ₃	1,370

TABLE A-1 OF SUBPART A—GLOBAL WARMING POTENTIALS (100-YEAR TIME HORIZON)—Continued

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
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
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)	NA	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)	NA	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	NA	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	156-05-3	CF ₃ CF ₂ OCH ₂ CF ₃	552
HFE-338pcc13 (HG-01)	NA	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	NA	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 CHFCF ₃	101
HFE-356pcc3	NA	CH ₃ OCF ₂ CF ₂ CHF ₂	110
HFE-356pcf2	NA	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	NA	CF ₃ CF ₂ CH ₂ OCH ₃	11
HFE-374pc2	512-51-6	CH ₃ CH ₂ OCF ₂ CHF ₂	557
HFE-449sl (HFE-7100) Chemical blend	163702-07-6	C ₄ F ₉ OCH ₃	297
	163702-08-7	(CF ₃) ₂ CF ₂ OCF ₂ OCH ₃	
HFE-569sf2 (HFE-7200) Chemical blend	163702-05-4	C ₄ F ₉ OC ₂ H ₅	59
	163702-06-5	(CF ₃) ₂ CF ₂ OC ₂ H ₅	
Sevoflurane	28523-86-6	CH ₃ FOCH(CF ₃) ₂	345
NA	13171-18-1	(CF ₃) ₂ CHOCH ₃	27
NA	26103-08-2	CHF ₂ OCH(CF ₃) ₂	380
NA	NA	-(CF ₂) ₄ CH(OH)-	73
NA	NA	CH ₃ OCF(CF ₃) ₂	343
NA	NA	(CF ₃) ₂ CHOH	195
NA	NA	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 × 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.

TABLE A-2 OF SUBPART A—UNITS OF MEASURE CONVERSIONS—Continued

To convert from	To	Multiply by
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.
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)	°C = (5/9) × (°F - 32).
Degrees Fahrenheit (°F)	Degrees Celsius (°C)	°F = (9/5) × °C + 32.
Degrees Celsius (°C)	Kelvin (K)	K = °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, combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include portable equipment or generating units designated as emergency generators in a permit issued

by a state or local air pollution control agency.

§ 98.31 Reporting threshold.

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

The owner or operator shall use the methodologies in this section to calculate the GHG emissions from stationary fuel combustion sources, except for electricity generating units that are subject to the Acid Rain Program. The GHG emissions

calculation methods for Acid Rain Program units are addressed in subpart D of this part.

(a) *CO₂ emissions from fuel combustion.* For each stationary fuel combustion unit, the owner or operator shall use the four-tiered approach in this paragraph, subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section.

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO₂ mass emissions for a particular type of fuel combusted in a unit, by substituting a fuel-specific default CO₂ emission factor (from Table C-1 of this subpart), a default high heating value (from Table C-1 of this subpart), and the annual fuel consumption (from company records kept as provided in this rule) into the 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 (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 a particular type of fuel

combusted in a unit, by substituting measured high heat values, a default CO₂ emission factor (from Table C-1 or Table C-2 of this subpart), and the quantity of fuel combusted (from company records kept as provided in this rule) into the following equations:

(i) Equation C-2a of this section applies to any type of fuel, except for municipal solid waste (MSW):

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

Where:

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

n = Number of required heat content measurements for the year.

(Fuel)_p = Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

p = Measurement period (month).

(HHV)_p = High heat value of the fuel for the measurement period (mmBtu per mass or volume).

EF = Fuel-specific default CO₂ emission factor, from Table C-1 or C-2 of this subpart (kg CO₂/mmBtu).

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

(ii) In Equation C-2a of this section, the value of "n" depends upon the frequency at which high heat value (HHV) measurements are required under § 98.34(c). For example, for natural gas, which requires monthly sampling and analysis, n = 6 if the unit combusts natural gas in only 6 months of the year.

(iii) For MSW combustion, use Equation C-2b of this section:

$$CO_2 = 1 \times 10^{-3} (Steam) (B) (EF) \quad (\text{Eq. C-2b})$$

Where:

CO₂ = Annual CO₂ mass emissions from MSW combustion (metric tons).

Steam = Total mass of steam generated by MSW 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 = Default CO₂ emission factor for MSW, from Table C-3 of this subpart (kg CO₂/mmBtu).

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

(3) *Tier 3 Calculation Methodology.* Calculate the annual CO₂ mass emissions for a particular type of fuel combusted in a unit, by substituting measurements of fuel carbon content, molecular weight (gaseous fuels, only), and the quantity of fuel combusted into the following Equations. For solid fuels,

the amount of fuel combusted is obtained from company records kept as provided in this rule. For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters). For fuel oil, tank drop measurements may also be used.

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

$$CO_2 = \sum_{p=1}^n \frac{44}{12} * (Fuel)_n * (CC)_n \quad (\text{Eq. C-3})$$

Where:

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

N = Number of required carbon content determinations for the year.

(Fuel)_n = Mass of the solid fuel combusted in month "n" (metric tons).

P = Measurement period (month).

(CC)_n = Carbon content of the solid fuel, from the fuel analysis results for month "n"

(percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

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

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

$$CO_2 = \sum_{p=1}^n \frac{44}{12} * (Fuel)_n * (CC)_n * 0.001 \quad (\text{Eq. C-4})$$

Where:

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

N = Number of required carbon content determinations for the year.

(Fuel)_n = Volume of the liquid fuel combusted in month "n" (gallons).

P = Measurement period (month).

(CC)_n = Carbon content of the liquid fuel, from the fuel analysis results for month "n" (kg C per gallon of fuel).

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:

$$CO_2 = \sum_{p=1}^n \frac{44}{12} * (Fuel)_n * (CC)_n * \frac{MW}{MVC} * 0.001 \quad (\text{Eq. C-5})$$

Where:

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

N = Number of required carbon content and molecular weight determinations for the year.

(Fuel)_n = Volume of the gaseous fuel combusted on day "n" or in month "n", as applicable (scf).

P = Measurement period (month or day, as applicable).

(CC)_n = Average carbon content of the gaseous fuel, from the fuel analysis results for the day or month, as applicable (kg C per kg of fuel).
 MW = Molecular weight of the gaseous fuel, from fuel analysis (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.

(iv) In applying Equation C-5 of this section to natural gas combustion, the CO₂ mass emissions are calculated only

for those months in which natural gas is combusted during the reporting year. For the combustion of other gaseous fuels (e.g., refinery gas or process gas), the CO₂ mass emissions are calculated only for those days on which the gaseous fuel is combusted during the reporting year. For example, if the unit combusts process gas on 250 of the 365 days in the year, then n = 250 in Equation C-5 of this section.

(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)(1)(iv)(D) 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 (tons/scf-% CO₂).

(iii) If the CO₂ concentration is measured on a dry basis, a correction for the stack gas moisture content is required. The owner or operator 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 (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 part 75 of this chapter, if the effluent gas stream monitored by the CEMS consists solely of combustion products and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to part 75 of this chapter 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 part 75 of this chapter, 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 the entire calendar year.

(vii) If both biogenic fuel and fossil fuel are combusted during the year, determine 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 may be used for any type of fuel combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, provided that:

(i) An applicable default CO₂ emission factor and an applicable default high heat value for the fuel are specified in Table C-1 of this subpart.

(ii) The owner or operator does not perform, or receive from the entity supplying the fuel, the results of fuel sampling and analysis on a monthly (or more frequent) basis that includes measurements of the HHV. If the owner or operator performs such fuel sampling and analysis or receives such fuel sampling and analysis results, the Tier 1 Calculation Methodology shall not be used, and the Tier 2, Tier 3, or Tier 4 Calculation Methodology shall be used instead.

(2) The Tier 1 Calculation Methodology may also be used to calculate the biogenic CO₂ emissions from a unit of any size that combusts wood, wood waste, or other solid biomass-derived fuels, except when the Tier 4 Calculation Methodology is used to quantify the total CO₂ mass emissions. If the Tier 4 Calculation Methodology is used, the biogenic CO₂ emissions shall be calculated according to paragraph (e) of this section.

(3) The Tier 2 Calculation Methodology may be used for any type of fuel combusted in any unit with a maximum rated heat input capacity of

250 mmBtu/hr or less, provided that a default CO₂ emission factor for the fuel is specified in Table C-1 or C-2 of this subpart.

(4) The Tier 3 Calculation Methodology may be used for a unit of any size, combusting any type of fuel, except when the use of Tier 4 is required or elected, as provided in paragraph (b)(5) of this section.

(5) The Tier 4 Calculation Methodology:

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

(ii) Shall be used for a unit if:

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

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

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

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

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

(F) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable Federal or State regulation or the unit's operating permit, to undergo periodic quality assurance testing in accordance with appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.

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

(A) Has both a stack gas volumetric flow rate monitor and a CO₂ concentration monitor.

(B) The unit meets the other conditions specified in paragraphs (b)(5)(ii)(B) and (C) of this section.

(C) The CO₂ and stack gas volumetric flow rate monitors meet the conditions

specified in paragraphs (b)(5)(ii)(D) through (b)(5)(ii)(F) of this section.

(6) The Tier 4 Calculation Methodology, if selected or required, shall be used beginning on:

(i) January 1, 2010, for a unit 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, the owner or operator shall use the Tier 3 Calculation Methodology in 2010.

(c) *Calculation of CH₄ and N₂O emissions from all fuel combustion.* Calculate the annual CH₄ and N₂O mass emissions from stationary fuel combustion sources as follows:

(1) For units subject to the requirements of the Acid Rain Program and for other units monitoring and reporting heat input on a year-round basis according to §§ 75.10(c) and 75.64 of this chapter, use Equation C-8 of this section:

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

Where:

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

(HI)_A = Cumulative annual heat input from the fuel, derived from the electronic data report required under § 75.64 of this chapter (mmBtu).

EF = Fuel-specific emission factor for CH₄ or N₂O, from Table C-3 of this subpart (kg CH₄ or N₂O per mmBtu).

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

(2) For all other units, use the applicable equations and procedures in paragraphs (c)(2) through (4) of this

section to calculate the annual CH₄ and N₂O emissions.

(i) If a default high heat value for a particular fuel is specified in Table C-1 of this subpart and if the HHV is not measured or provided by the entity supplying the fuel on a monthly (or more frequent) basis throughout the year, use Equation C-9 of this section:

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

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, from company records (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-3 of this subpart (kg CH₄ or N₂O per mmBtu).

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

(ii) If the high heat value of a particular fuel (except for municipal solid waste) is measured on a monthly (or more frequent) basis throughout the year, or if such data are provided by the entity supplying the fuel, use Equation C-10a of this section:

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

Where:

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

n = Number of required heat content measurements for the year.

(Fuel)_p = Mass or volume of the fuel combusted during the measurement

period "p" (mass or volume per unit time).
 (HHV)_p = Measured high heat value of the fuel for period "p" (mmBtu per mass or volume).
 p = Measurement period (day or month, as applicable).

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C-3 of this subpart (kg CH₄ or N₂O per mmBtu).
 1 x 10⁻³ = Conversion factor from kilograms to metric tons.

(iii) For municipal solid waste combustion, use Equation C-10b of this section to estimate CH₄ and N₂O emissions:

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} (\text{Steam}) (B) (EF) \quad (\text{Eq. C-10b})$$

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a municipal solid waste (metric tons).

Steam = Total mass of steam generated by MSW 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-3 of this subpart (kg CH₄ or N₂O per mmBtu).

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

(3) Multiply the result from Equations C-8, C-9, C-10a, or C-10b of this section (as applicable) by the global warming potential (GWP) factor to convert the CH₄ or N₂O emissions to metric tons of CO₂ equivalent.

(4) If, for a particular type of fuel, default CH₄ and N₂O emission factors are not provided in Table C-4 of this subpart, the owner or operator may, subject to the approval of the Administrator, develop site-specific CH₄ and N₂O emission factors, based on the results of source testing.

(d) *Calculation of CO₂ from sorbent* 1. 2

(vi) Calculate the annual biogenic CO₂ mass emissions, in metric tons, by multiplying the percent Biogenic obtained from Equation C-14 of this section of this section by the total annual CO₂ mass emissions in metric tons, as determined under paragraph (a)(1)(iv) of this section.

(3) For a unit that combusts MSW, the owner or operator shall use, for each quarter, ASTM Methods D 6866-06a and D 7459-08, as described in § 98.34(f), to determine the relative proportions of biogenic and non-biogenic CO₂ emissions when MSW is combusted. The results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO₂ from MSW combustion is biogenic), and the quarterly values shall be averaged over the reporting year. The annual biogenic CO₂ emissions shall be calculated as follows:

(i) If the unit qualifies for the Tier 2 or Tier 3 Calculation Methodology of this section and the owner or operator elects to use the Tier 2 or Tier 3 Calculation Methodology to quantify GHG emissions:

(A) Use Equations C-2a, C-2b and C-3 of this section, as applicable, to calculate the annual CO₂ mass emissions from MSW combustion and from any auxiliary fuels such as natural gas. Sum these values, to obtain the total annual CO₂ mass emissions from the unit.

(B) Determine the annual biogenic CO₂ mass emissions from MSW combustion as follows. Multiply the total annual CO₂ mass emissions from MSW combustion by the biogenic decimal fraction obtained from ASTM Methods D 6866-06a and D 7459-08.

(ii) If the unit uses CEMS 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 total annual volume of CO₂ emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO₂ emissions from MSW combustion as follows. Multiply the annual volume of CO₂ emissions from MSW combustion by the biogenic decimal fraction obtained from ASTM Methods D 6866-06a and D 7459-08.

(E) Calculate the biogenic percentage of the total annual CO₂ 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 CO₂ mass emissions according to paragraph (e)(2)(vi) of this section.

(4) For biogas combustion, the Tier 2 or Tier 3 Calculation Methodology shall be used to determine the annual biogenic CO₂ mass emissions, except as provided in paragraph (e)(2) of this section.

§ 98.34 Monitoring and QA/QC requirements.

The CO₂ mass emissions data for stationary combustion units shall be quality-assured as follows:

(a) For units using the calculation methodologies described in this paragraph, the records required under § 98.33(g) shall include both the company records and a detailed explanation of how company records are used to estimate the following:

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies described in § 98.33(a) are used.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology in § 98.33(a)(3) is used.

(3) 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.

(4) Sorbent usage, if the methodology in § 98.33(d) is used to calculate CO₂ emissions from sorbent.

(b) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage and sorbent usage (as applicable) in paragraph (a) of this section, 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.

(c) For the Tier 2 Calculation Methodology, the applicable fuel sampling and analysis methods incorporated by reference in § 98.7 shall be used to determine the high heat values. For coal, the samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed. The minimum frequency of the sampling and analysis for each type of fuel (only for the weeks or months when that fuel is combusted in the unit) is as follows:

(1) Monthly, for natural gas, biogas, fuel oil, and other liquid fuels.

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

(d) For the Tier 3 Calculation Methodology:

(1) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this part, using an applicable flow meter test method listed in § 98.7 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(2) Oil tank drop measurements (if applicable) shall be performed according to one of the methods listed in § 98.7.

(3) The carbon content of the fuels listed in paragraphs (c)(1) and (2) of this section shall be determined monthly.

For other gaseous fuels (e.g., refinery gas, or process gas), daily sampling and analysis is required to determine the carbon content and molecular weight of the fuel. An applicable method listed in § 98.7 shall be used to determine the carbon content and (if applicable) molecular weight of the fuel.

(e) 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)(6).

(1) For initial certification, use the following procedures:

(i) Section 75.20(c)(2) and (4) and appendix A to part 75) of this chapter.

(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 part 75 of this chapter, part 60 of this chapter, 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 appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. If appendix F to

part 60 of this chapter is selected for on-going quality assurance, perform daily calibration drift (CD) assessments for both the CO₂ and flow rate monitors, 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 part 75 of this chapter and the annual RATAs of the CERMS required by appendix F to part 60 of this chapter need only be done at one operating level, representing normal load or normal process operating conditions,

common stack, in lieu of reporting separately the GHG emissions from the individual units. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack ID number, beginning with the prefix "CS".

(ii) ID numbers of the units sharing the common stack.

(iii) Maximum rated heat input capacity of each unit sharing the common stack (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., CEMS or the Tier 4 Calculation Methodology).

(vi) The total CO₂ mass emissions measured at the common stack for the year, expressed in metric tons of CO₂e.

(vii) The combined annual CH₄ and N₂O emissions from the units sharing the common stack, expressed in metric tons of each gas and in metric tons of CO₂e.

(A) If the monitoring is done according to part 75 of this chapter, use Equation C-8 of this subpart, where the term "(HI)_A" is the cumulative annual heat input measured at the common stack.

(B) For the Tier 4 calculation methodology, use Equation C-9, C-10a or C-10b of this subpart separately for each type of fuel combusted in the units during the year, and then sum the emissions for all fuel types.

(viii) The total GHG emissions for the year from the units that share the common stack, 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 oil-fired or gas-fired stationary combustion units at a facility combust the same type of fuel and that fuel is fed to the individual units through a common supply line or pipe, the owner or operator may report the combined emissions from the units served by the common supply line, in lieu of reporting separately 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 calibrated fuel flow meter. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe ID number, beginning with the prefix "CP".

(ii) ID 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 type of fuel combusted in the units during the reporting year.

(v) The methodology used to calculate the CO₂ mass emissions.

(vi) The total CO₂ mass emissions from the units served by the common pipe for the reporting year, expressed in metric tons of CO₂e.

(vii) The combined 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) The total GHG emissions for the reporting year from the units served by the common pipe, i.e., the sum of the CO₂, CH₄, and N₂O emissions, expressed in metric tons of CO₂e.

(d) *Verification data.* The owner or operator shall report sufficient data and supplementary information to verify the reported GHG emissions.

(1) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, or Tier 4 Calculation Methodology in § 98.33(a)(4) to quantify CO₂ emissions, the following additional information shall be included in the GHG emissions report:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted during the reporting year, in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted during each month (except for MSW). 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 number of required high heat value determinations for each type of fuel for the reporting year (i.e., "n" in Equation C-2a of this subpart, corresponding (as applicable) to the number of operating days or months when each type of fuel was combusted, in accordance with § 98.33(a)(2) and 98.34(c).

(C) For each month, the high heat value used in Equation C-2a of this subpart 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.

(D) For each reported HHV, indicate whether it is an actual measured value or a substitute data value.

(E) Each method from § 98.7 used to determine the HHV for each type of fuel combusted.

(F) For MSW, the total quantity (i.e., lb) of steam produced from MSW combustion during the year, and "B", the ratio of the unit's maximum rate

heat input capacity to its design rated steam output capacity, in mmBtu per lb of steam.

(iii) For the Tier 3 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted during each month or day (as applicable), in metric tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The number of required carbon content determinations for each type of fuel for the reporting year, corresponding (as applicable) to the number of operating days or months when each type of fuel was combusted, in accordance with §§ 98.33(a)(3) and 98.34(d).

(C) For each operating month or day, the carbon content (CC) value used in Equation C-3, C-4, or C-5 of this subpart (as applicable), expressed as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels.

(D) For gaseous fuel combustion, the molecular weight of the fuel used in Equation C-5 of this subpart, for each operating month or day, in kg per kg-mole.

(E) For each reported CC value, indicate whether it is an actual measured value or a substitute data value.

(F) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the fuel flow meters used to measure the amount of fuel combusted.

(G) For fuel oil combustion, each method from § 98.7 used to make tank drop measurements (if applicable).

(H) Each method from § 98.7 used to determine the CC for each type of fuel combusted.

(I) Each method from § 98.7 used to calibrate the fuel flow meters (if applicable).

(iv) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating days and the total number of source operating hours in the reporting year.

(B) Whether the CEMS certification and quality assurance procedures of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program have been selected.

(C) The CO₂ emissions on each operating day, i.e., the sum of the hourly values calculated from Equation C-6 or C-7 (as applicable), in metric tons.

(D) For CO₂ concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the number of source operating hours in which a substitute

data value of each parameter was used in the emissions calculations.

(E) The dates and results of the initial certification tests of the CEMS, and

(F) 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).

(v) 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 metric tons.

(B) The molecular weight of the sorbent.

(C) The ratio (“R”) in Equation C–11 of this subpart.

(vi) When ASTM methods D7459–08 and D6866–06a are used to determine the biogenic portion of the annual CO₂ emissions from MSW combustion, as described in §§ 98.33(e) and 98.34(f), the owner or operator shall 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) The total quantity of MSW combusted during the reporting year, in short tons if the Tier 2 Calculation Methodology is used or in metric tons if the Tier 3 calculation methodology is used.

(vii) For units that combust both fossil fuel and biogenic fuel, when CEMS are used to quantify the annual CO₂ emissions, the owner or operator 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 biogenic fuels, i.e., V_{bio}, in scf.

(D) The carbon-based F-factor used in Equation C–14 of this subpart, for each type of fossil fuel combusted, in scf CO₂ per mmBtu.

(E) The annual average GCV value used in Equation C–14 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) The total annual biogenic CO₂ mass emissions, in metric tons.

(2) Within 7 days of receipt of a written request (e.g., a request by electronic mail) from the Administrator or from the applicable State or local air pollution control agency, the owner or operator shall submit the explanations described in § 98.34(a) and (b), as follows:

(i) A detailed explanation of how company records are used to quantify fuel consumption, if Calculation Methodology Tier 1 or Tier 2 of this

subpart is used to calculate CO₂ emissions.

(ii) A detailed explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology in § 98.33(a)(3) is used to calculate CO₂ emissions.

(iii) A detailed explanation of how sorbent usage is quantified, if the methodology in § 98.33(d) is used to calculate CO₂ emissions from sorbent.

(iv) A detailed explanation of how company records are used to quantify fossil fuel consumption, when, as described in § 98.33(e), the owner or operator of a unit that combusts both fossil fuel and biogenic fuel uses CEMS to quantify CO₂ emissions.

§ 98.37 Records that must be retained.

The recordkeeping requirements of § 98.3(g) and, if applicable, § 98.34(a) and (b) shall be fully met for affected facilities with stationary combustion sources. Also, the records required under § 98.35(a)(1), documenting the data substitution procedures for missing stack flow rate, fuel flow rate, fuel usage and (if applicable) sorbent usage information and site-specific source testing (as allowed in § 98.33(c)(4)), shall be retained. No special recordkeeping beyond that specified in §§ 98.3, 98.35(a)(4), and 98.34(a) and (b) is required. All required records must be retained for a period of five years.

§ 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 CO ₂ emission factor
Coal and Coke		
	mmBtu/short ton	kg CO ₂ /mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Sub-bituminous	17.25	97.02
Lignite	14.21	96.36
Unspecified (Residential/Commercial)	22.24	95.26
Unspecified (Industrial Coking)	26.28	93.65
Unspecified (Other Industrial)	22.18	93.91
Unspecified (Electric Power)	19.97	94.38.
Coke	24.80	102.04
Natural Gas		
	mmBtu/scf	kg CO ₂ /mmBtu.
Unspecified (Weighted U.S. Average)	1.027 x 10 ⁻³	53.02
Petroleum Products		
	mmBtu/gallon	kg CO ₂ /mmBtu
Asphalt & Road Oil	0.158	75.55
Aviation gasoline	0.120	69.14
Distillate Fuel Oil (# 1, 2, & 4)	0.139	73.10
Jet Fuel	0.135	70.83
Kerosene	0.135	72.25
LPG (energy use)	0.092	62.98

TABLE C-1 OF SUBPART C—DEFAULT CO₂ EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default high heat value	Default CO ₂ emission factor
Propane	0.091	63.02
Ethane	0.069	59.54
Isobutane	0.099	65.04
n-Butane	0.103	64.93
Lubricants	0.144	74.16
Motor Gasoline	0.124	70.83
Residual Fuel Oil (# 5 & 6)	0.150	78.74
Crude Oil	0.138	74.49
Naphtha (< 401 deg. F)	0.125	66.46
Natural Gasoline	0.110	66.83
Other Oil (> 401 deg. F)	0.139	73.10
Pentanes Plus	0.110	66.83
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.04
Special Naphtha	0.125	72.77
Unfinished Oils	0.139	74.49
Waxes	0.132	72.58
Biomass-derived Fuels (solid)	mmBtu/short Ton	kg CO₂/mmBtu
Wood and Wood waste (12% moisture content) or other solid biomass-derived fuels	15.38	93.80
Biomass-derived Fuels (Gas)	mmBtu/scf	kg CO₂/mmBtu
Biogas	Varies	52.07

Note: Heat content factors are based on higher heating values (HHV). Also, for petroleum products, the default heat content values have been converted from units of mmBtu per barrel to mmBtu per gallon.

TABLE C-2 OF SUBPART C—DEFAULT CO₂ EMISSION FACTORS FOR THE COMBUSTION OF ALTERNATIVE FUELS

Fuel type	Default CO ₂ emission factor (kg CO ₂ /mmBtu)
Waste Oil	74
Tires	85
Plastics	75
Solvents	74
Impregnated Saw Dust	75
Other Fossil based wastes	80
Dried Sewage Sludge	110
Mixed Industrial waste	83
Municipal Solid Waste	90.652

Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.

TABLE C-3 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)
Asphalt	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Aviation Gasoline	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Coal	1.0 × 10 ⁻²	1.5 × 10 ⁻³
Crude Oil	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Digester Gas	9.0 × 10 ⁻⁴	1.0 × 10 ⁻⁴
Distillate	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Gasoline	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Jet Fuel	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Kerosene	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Landfill Gas	9.0 × 10 ⁻⁴	1.0 × 10 ⁻⁴
LPG	1.0 × 10 ⁻³	1.0 × 10 ⁻⁴
Lubricants	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Municipal Solid Waste	3.0 × 10 ⁻²	4.0 × 10 ⁻³
Naphtha	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Natural Gas	9.0 × 10 ⁻⁴	1.0 × 10 ⁻⁴
Natural Gas Liquids	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Other Biomass	3.0 × 10 ⁻²	4.0 × 10 ⁻³

TABLE C-3 OF SUBPART C—DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default CH ₄ emission factor (kg CH ₄ /mmBtu)	Default N ₂ O emission factor (kg N ₂ O/mmBtu)
Petroleum Coke	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴
Propane	1.0 × 10 ⁻³	1.0 × 10 ⁻⁴
Refinery Gas	9.0 × 10 ⁻⁴	1.0 × 10 ⁻⁴
Residual Fuel Oil	3.0 × 10 ⁻³	6.0 × 10 ⁻⁴

each adipic acid oxidation process. You must conduct the performance test under normal process operating conditions.

(b) You must conduct the emissions test using the methods specified in § 98.54(b).

(c) You must measure the adipic acid production rate for the facility during the test and calculate the production

rate for the test period in metric tons per hour.

(d) You must calculate an average facility-specific emission factor according to Equation E-1 of this section:

$$EF_{N_2O} = \frac{\sum_{i=1}^n C_{N_2O} * 1.14 \times 10^{-7} * Q}{P} \quad (\text{Eq. E-1})$$

Where:

EF_{N_2O} = Average facility-specific N_2O emissions factor (lb N_2O /ton adipic acid produced).

C_{N_2O} = N_2O concentration during performance test (ppm N_2O).

1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).

Q = Volumetric flow rate of effluent gas (dscf/hr).

P = Production rate during performance test (tons adipic acid produced/hr).

n = Number of test runs.

(e) You must calculate annual adipic acid production process emissions of N_2O for the facility by multiplying the emissions factor by the total annual adipic acid production at the facility, according to Equation E-2 of this section:

$$E_{N_2O} = \frac{EF_{N_2O} * P_a * (1 - DF_N) * AF_N}{2205} \quad (\text{Eq. E-2})$$

Where:

E_{N_2O} = N_2O mass emissions per year (metric tons of N_2O).

EF_{N_2O} = Facility-specific N_2O emission factor (lb N_2O /ton adipic acid produced).

P_a = Total production for the year (ton adipic acid produced).

DF_N = Destruction factor of N_2O abatement technology (abatement device manufacturer's specified destruction efficiency, percent of N_2O removed from air stream).

AF_N = Abatement factor of N_2O abatement technology (percent of year that abatement technology was used).

2205 = Conversion factor (lb/metric ton).

applicable EPA methods in 40 CFR part 60, appendices A-1 through A-4.

Conduct three emissions test runs of 1 hour each.

(c) Each facility must conduct all required performance tests according to a test plan and EPA Method 320 in 40 CFR part 63, appendix A or ASTM D6348-03 (incorporated by reference—see § 98.7). 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)(1) through (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 during the test and how it was determined. The production rate can be determined through sales records, or through direct measurement using flow meters or weigh scales.

must contain the information specified in paragraphs (a) through (h) of this section for each adipic acid production facility:

(a) Annual N_2O emissions from adipic acid production in metric tons.

(b) Annual adipic acid production capacity (in metric tons).

(c) Annual adipic acid production, in units of metric tons of adipic acid produced.

(d) Number of facility operating hours in calendar year.

(e) Emission rate factor used (lb N_2O /ton adipic acid).

(f) Abatement technology used (if applicable).

(g) Abatement technology efficiency (percent destruction).

(h) Abatement utilization factor (percent of time that abatement system is operating).

§ 98.54 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new facility-specific emissions factor at least annually. You must also conduct a new performance test whenever the production rate is changed by more than 10 percent from the production rate measured during the most recent performance test. The new emissions factor may be calculated using all available performance test data (i.e., average with the data from previous years), except in cases where process modifications have occurred or operating conditions have changed. Only the data consistent with the reporting period after the changes were implemented shall be used.

(b) You must conduct each emissions test using EPA Method 320 in 40 CFR part 63, Appendix A or ASTM D6348-03 (incorporated by reference—see § 98.7) to measure the N_2O concentration in conjunction with the

§ 98.55 Procedures for estimating missing data.

Procedures for estimating missing data are not provided for N_2O process emissions for adipic acid production facilities calculated according to § 98.53. A complete record of all measured parameters used in the GHG emissions calculations is required.

§ 98.56 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report

§ 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 (f) of this section at the facility level:

(a) Annual N_2O emissions from adipic acid production, in metric tons.

(b) Annual adipic acid production capacity, in metric tons.

(c) Annual adipic acid production, in units of metric tons of adipic acid produced.

(d) Number of facility operating hours in calendar year.

(e) Measurements, records and calculations used to determine the annual production rate.

(f) Emission rate factor used and supporting test or calculation information including the annual emission rate factor determination report specified in § 98.54(c). This report must be available upon request.

§ 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 (2).

§ 98.62 GHGs to report.

You must report:

- (a) Total perfluoromethane (CF₄), and perfluoroethane (C₂F₆) emissions from

anode effects in all prebake and Søderberg electrolysis cells.

(b) Total CO₂ emissions from anode consumption during electrolysis in all prebake and Søderberg electrolysis cells.

(c) Total CO₂ emissions from anode baking for all prebake cells.

(d) For CO₂, N₂O, and CH₄ emissions from stationary fuel combustion units, you must follow the requirements in subpart C of this part.

§ 98.63 Calculating GHG emissions.

(a) Use Equation F-1 of this section to estimate CF₄ emissions from anode effects, and use Equation F-2 to estimate C₂F₆ emissions from anode effects from each prebake and Søderberg electrolysis cell.

$$E_{CF_4} = S_{CF_4} \times AEM \times MP \times 0.001 \quad (\text{Eq. F-1})$$

Where:

E_{CF_4} = Monthly CF₄ emissions from aluminum production (metric tons CF₄).

S_{CF_4} = 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.

$$E_{C_2F_6} = E_{CF_4} \times F_{C_2F_6/CF_4} \times 0.001 \quad (\text{Eq. F-2})$$

Where:

$E_{C_2F_6}$ = Monthly C₂F₆ emissions from aluminum production (metric tons C₂F₆).
 E_{CF_4} = CF₄ emissions from aluminum production (kg CF₄).
 $F_{C_2F_6/CF_4}$ = The weight fraction of C₂F₆/CF₄ (kg C₂F₆/kg CF₄).

0.001 = Conversion factor from kg to metric tons, where E_{CF_4} is calculated monthly.

(b) 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-3 of this section:

$$E_{CO_2} = NAC \times MP \times \left(\frac{100 - S_a - Ash_a}{100} \right) \times (44/12) \quad (\text{Eq. F-3})$$

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 = Total 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-4 of this section:

$$E_{CO_2} = (PC \times MP - [CSM \times MP]/1000 - BC/100 \times PC \times MP \times [S_p + Ash_p + H_p]/100 - [100 - BC]/100 \times PC \times MP \times [S_c + Ash_c]/100 - MP \times CD \times (44/12) \quad (\text{Eq. F-4})$$

Where:

E_{CO_2} = Annual CO₂ emissions from paste consumption (metric ton CO₂).
PC = Annual paste consumption (metric ton/metric ton Al).
MP = Total 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, CO₂ to carbon.

(c) Use the following procedures to calculate CO₂ emissions from anode baking of prebake cells:



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Where:

CO₂ = 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 = Average carbon content of the solid feedstock, from the analysis results for month n (kg C per kg of feedstock).

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

0.001 = Conversion factor from kg to metric tons.

(R_{CO₂})_n = CO₂ captured or recovered for use in urea or methanol production for month n, kg CO₂.

§ 98.74 Monitoring and QA/QC requirements.

(a) Facilities 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 collect a sample of each feedstock on a monthly basis and analyze the carbon content using any suitable method incorporated by reference in § 98.7.

(c) All fuel flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(d) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

§ 98.75 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 shall be used in the calculations, according to the requirements in paragraphs (a) and (b) of this section.

(a) For missing feedstock supply rates, use the lesser of the maximum supply rate that the unit is capable of processing or the maximum supply rate that the meter can measure.

(b) There are no missing data procedures for carbon content. A re-test must be performed if the data from any monthly measurements are determined to be invalid.

§ 98.76 Data reporting requirements.

In addition to the information required by § 98.3(c) of subpart A of this part, each annual report must contain the information specified in paragraphs (a) through (c) for each ammonia manufacturing process unit:

(a) Annual CO₂ process emissions (metric tons).

(b) Total quantity of feedstock consumed for ammonia manufacturing.

(c) Monthly analyses of carbon content for each feedstock used in ammonia manufacturing (kg carbon/kg of feedstock).

§ 98.77 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) Method used for determining quantity of feedstock used.

(b) Monthly analyses of carbon content for each feedstock used in ammonia manufacturing.

§ 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.

Carbon dioxide (CO₂) process emissions from calcination, reported for all kilns combined.

CO₂, N₂O, and CH₄ emissions from fuel combustion at each kiln and any other stationary combustion units, by following the requirements of 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources).

§ 98.83 Calculating GHG emissions.

(a) Cement kilns that meet the conditions specified in § 98.33(b)(5)(ii) or (iii) shall calculate total CO₂ emissions using the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) If CEMS are not used to determine the total annual CO₂ emissions from kilns, then you must calculate process CO₂ emissions by following paragraphs (b)(1) through (3) of this section.

(1) Calculate CO₂ process emissions from all kilns at the facility using Equation H-1 of this section:

$$CO_2_{CMF} = \sum_{m=1}^k CO_2_{cli,m} + CO_2_{rm} \quad (\text{Eq. H-1})$$

Where:

CO₂_{CMF} = Total annual emissions of CO₂ from cement manufacturing, metric tons.

CO₂_{cli,m} = Total annual emissions of CO₂ from clinker production from kiln m, metric tons.

CO₂_{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 and H-3 of this section.

$$CO_2_{cli,m} = \sum_{j=1}^p [(Cli_j) * (EFcli_j)] + \sum_{i=1}^r [(CKD_i) * (EFCKD_i)] \quad (\text{Eq. H-2})$$

Where:

$Cl_{i,j}$ = Quantity of clinker produced in month j from kiln m, metric tons.
 $EF_{Cl_{i,j}}$ = Kiln specific clinker emission factor for month j for kiln m, metric tons CO₂/

metric ton clinker computed as specified in Equation H-3 of this section.
 CKD_i = Cement kiln dust (CKD) discarded in quarter i from kiln m, metric tons.
 $EF_{CKD,i}$ = Kiln specific fraction of calcined material in CKD not recycled to the kiln,

for quarter i from kiln m, as determined in paragraph (c)(2)(i).

p = Number of months for clinker calculation, 12.
r = Number of quarters for CKD calculation, 4.

$$EF_{Cl_i} = (Cl_{CaO} - Cl_{ncCaO}) * MR_{CaO} + (Cl_{MgO} - Cl_{ncMgO}) * MR_{MgO} \quad (\text{Eq. H-3})$$

Where:

Cl_{CaO} = Monthly CaO content of Clinker, wt% as determined in § 98.84(b).
 MR_{CaO} = Molecular Ratio of CO₂/CaO = 0.785.
 Cl_{MgO} = Monthly MgO content of Clinker, wt% as determined in § 98.84(b).
 MR_{MgO} = Molecular Ratio of CO₂/MgO = 1.092.
 Cl_{ncCaO} = Monthly non-carbonate CaO of Clinker, wt% as determined in § 98.84(b).

Cl_{ncMgO} = Monthly non-carbonate MgO of Clinker, wt% as determined in § 98.84(b).

(i) EF_{CKD} must be determined through X-ray fluorescence (XRF) test or other testing method specified in § 98.84(a), except as provided in paragraph (c)(2)(ii) of this section.

(ii) A default factor of 1.0, which assumes that 100 percent of all carbonates in CKD are calcined, may be

used instead of testing to determine EF_{CKD} .

(iii) The weight percents of CaO, MgO, non-carbonate CaO, and non-carbonate MgO of clinker used in Equation H-3 must be determined using the measurement methods specified in § 98.84(b).

(3) *CO₂ emissions from raw materials.* Calculate CO₂ emissions using Equation H-4 of this section:

$$CO_2 \text{ }_{m} = rm * TOC \text{ }_{m} * 3.664 \quad (\text{Eq. H-4})$$

Where:

rm = The amount of raw material consumed annually, metric tons/yr.
 $TOC \text{ }_{m}$ = Organic carbon content of raw material, as determined in § 98.84(c) or using a default factor of 0.2 percent of total raw material weight.
3.664 = The CO₂ to carbon molar ratio.

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 discarded quarterly 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.

(f) The quantity of each category of raw materials consumed annually by the facility (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(a) The total combined CO₂ emissions from all kilns at the facility (in metric tons).

(b) Annual clinker production (tons).

(c) Number of kilns.

(d) Annual CKD production (in metric tons).

(e) Total annual fraction of CKD recycled to the kilns (as a percentage).

(f) Annual weighted average carbonate composition (by carbonate).

(g) Annual weighted average fraction of calcination achieved (for each carbonate, percent).

(h) Site-specific emission factor (metric tons CO₂/metric ton clinker produced).

(i) Organic carbon content of the raw material (percent).

(j) Annual consumption of raw material (metric tons).

(k) Facilities that use CEMS must also comply with the data reporting requirements specified in § 98.36(d)(iv).

§ 98.84 Monitoring and QA/QC requirements.

(a) You must determine the plant-specific fraction of calcined material in cement kiln dust (CKD) not recycled to the kiln (EF_{CKD}) using an x-ray fluorescence test or other enhanced testing method. The monitoring must be conducted quarterly for each kiln from a CKD sample drawn from bulk CKD storage.

(b) You must determine the weight percents of CaO, MgO, non-carbonate CaO, and non-carbonate MgO in clinker from each kiln using an x-ray fluorescence test or other enhanced testing method. The monitoring must be conducted monthly for each kiln from a clinker sample drawn from bulk clinker storage.

(c) The total organic carbon contents of raw materials must be determined annually using ASTM Method C114-07 or a similar ASTM 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).

(d) The quantity of clinker produced monthly by each kiln must be

§ 98.85 Procedures for estimating missing data.

If the CEMS approach is used to determine CO₂ emissions, the missing data procedures in § 98.35 apply. Procedures for estimating missing data do not apply to CO₂ process emissions from cement manufacturing facilities calculated according to § 98.83(b). If data on the carbonate content or organic carbon content is missing, facilities must undertake a new analysis.

§ 98.86 Data reporting requirements.

In addition to the information required by § 98.3(b) of this part, each annual report must contain the information specified in paragraphs (a) through (k) of this section for each portland cement manufacturing facility.

§ 98.87 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 (i) of this section for each portland cement manufacturing facility.

(a) Monthly carbonate consumption.

(b) Monthly clinker production (tons).

(c) Monthly CKD production (in metric tons).

(d) Total annual fraction of CKD recycled to the kiln (as a percentage).

(e) Monthly analysis of carbonate composition in clinker (by carbonate).

(f) Monthly analysis of fraction of calcination achieved for CKD and each carbonate.

Where:

BE_{kij} = Annual emissions of by-product k formed from input gas i during process j (metric tons).

B_{kij} = Kg of gas k created as a by-product per kg of input gas i consumed in process j.

C_{ij} = Amount of input gas i consumed in process j (kg).

a_{ij} = Fraction of input gas i used in process j with abatement devices.

d_{kj} = Fraction of by-product gas k destroyed in abatement devices connected to

process (j). This is zero unless the facility verifies the DRE of the device pursuant to § 98.94(c) of Subpart I.

0.001 = Conversion factor from kg to metric tons.

(d) You shall report annual N_2O facility-level emissions during chemical vapor deposition using Equation I-7 of this section.

$$E(N_2O) = C_{N_2O} \times 0.001 \quad (\text{Eq. I-7})$$

Where:

$E(N_2O)$ = Annual emissions of N_2O (metric tons/year).

C_{N_2O} = Annual Consumption of N_2O (kg).

0.001 = Conversion factor from kg to metric tons.

(e) For facilities that use heat transfer fluids, you shall report the annual emissions of fluorinated GHG heat transfer fluids using Equation I-8 of this section.

$$EH_i = \text{density} * [I_{io} + P_{it} - N_{it} + R_{it} - I_{it} - D_{it} * 0.001] \quad (\text{Eq. I-8})$$

Where:

EH_i = Emissions of fluorinated GHG heat transfer fluid i, (metric tons/year).

Density = Density of heat transfer fluid i (kg/l).

I_{io} = Inventory of heat transfer fluid i at the end of previous reporting period (l).

P_{it} = Net purchases of heat transfer fluid i during the current reporting period (l).

N_{it} = Total nameplate capacity [charge] of equipment that contains heat transfer fluid i and that is installed during the current reporting period.

R_{it} = Total nameplate capacity [charge] of equipment that contains heat transfer fluid i and that is retired during the current reporting period.

I_{it} = Inventory of heat transfer fluid i at the end of current reporting period (l).

D_{it} = Amount of heat transfer fluid i recovered and sent off site during current reporting period, (l).

0.001 = Conversion factor from kg to metric tons.

§ 98.94 Monitoring and QA/QC requirements.

(a) You must estimate gas consumption according to the requirements in paragraph (a)(1) or (a)(2) of this section for each process or process type, as appropriate.

(1) Monitor changes in container mass and inventories for each gas using weigh scales with an accuracy and precision of one percent of full scale or better. Calculate the gas consumption using Equation I-9 of this section.

$$C_i = I_{Bi} - I_{Ei} + A - D * 0.001 \quad (\text{Eq. I-9})$$

Where:

C_i = Annual consumption of input gas i (metric tons/year).

I_{Bi} = Inventory of input gas i stored in cylinders or other containers at the beginning of the year, including heels (kg).

I_{Ei} = Inventory of input gas i stored in cylinders or other containers at the end of the year, including heels (kg).

A = Acquisitions of that gas during the year through purchases or other transactions, including heels in cylinders or other containers returned to the electronics production facility (kg).

D = Disbursements of gas through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics production facility to the gas distributor (kg).

0.001 = Conversion factor from kg to metric tons.

(2) Monitor the mass flow of the pure gas into the system using flowmeters. The flowmeters must have an accuracy and precision of one percent of full scale or better.

(b) If you use fluorinated GHG utilization rates and by-product emission factors other than the defaults in Tables I-2, I-3, or I-4 of Subpart I, you must use fluorinated GHG utilization rates and by-product emission factors that have been

measured using the International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment. You may use fluorinated GHG utilization rates and by-product emission factors measured by manufacturing equipment suppliers if the conditions in paragraph (b)(1) and (2) of this section are met.

(1) The manufacturing equipment supplier has measured the GHG utilization rates and by-product emission factors using the International SEMATECH Guideline.

(2) The conditions under which the measurements were made are representative of your facility's F-GHG emitting processes.

(c) If your facility employs abatement devices and you wish to reflect the emission reductions due to these devices in § 98.93(c), you must verify the destruction or removal efficiency (DRE) of the devices using the methods in either paragraph (c)(1) or (2) of this section.

(1) Experimentally determine the effective dilution through the abatement device and measure abatement DRE during actual or simulated process conditions by following the procedures of this paragraph.

(i) Measure the concentrations of F-GHGs exiting the process tool and entering and exiting the abatement system under operating process and abatement system conditions that are representative of those for which F-GHG emissions are estimated and abatement-system DRE is used for the F-GHG reporting period.¹

(ii) Measure the dilution through the abatement system and calculate the dilution factor under the representative operating conditions given in paragraph (c)(i) of this section by using the tracer method. This method consists of injecting known flows of a non-reactive gas (such as krypton) at the inlet of the abatement system, measuring the time-averaged concentrations of krypton entering ($[Kr]_{in}$) and exiting ($[Kr]_{out}$) the abatement system, and calculating the dilution factor (DF) as the ratio of the time-averaged measured krypton concentrations entering and exiting the abatement system, using equation I-10 of this section.

¹ Abatement system means a point-of-use (POU) abatement system whereby a single abatement system is attached to a single process tool or single process chamber of a multi-chamber tool.

$$DF = \frac{[Kr]_{in}}{[Kr]_{out}} \quad (\text{Eq. I-10})$$

(iii) Measure the F-GHG concentrations in and out of the device with all process chambers connected to the F-GHG abatement system and under the production and abatement system conditions for which F-GHG emissions are estimated for the reporting period.²

(iv) Calculate abatement system DRE using Equation I-11 of this section, where it is assumed that the measurement pressure and temperature at the inlet and outlet of the abatement system are identical and where the relative precision (ϵ) of the quantity $c_{i-out} * DF / c_{i-in}$ shall not exceed ± 10 percent (two standard deviations) using proper statistical methods.

$$d_{ij} = 1 - \frac{DF * c_{i-out}}{c_{i-in}} \quad (\text{Eq. I-11})$$

Where:

d_{ij} = Destruction or removal efficiency (DRE)

c_{i-in} = Concentration of gas i in the inflow to the abatement system (ppm).

c_{i-out} = Concentration of gas i in the outflow from the abatement system (ppm).

DF = Dilution Factor calculated using Equation I-10.

(v) The DF may not be obtained by calculation from flows other than those obtained by using the tracer method described in paragraph (ii) of this section.

(2) Install abatement devices that have been tested by a third party (e.g., UL) according to EPA's Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing. This testing may be obtained by the manufacturer of the equipment.

(d) Abatement devices must be operated within the manufacturer's specified equipment lifetime and gas flow and mix limits and must be maintained according to the manufacturer's guidelines.

(e) You shall adhere to the QA/QC procedures of this paragraph when estimating F-GHG and N₂O emissions from cleaning/etching processes:

(1) You shall follow the QA/QC procedures in the International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor

Process Equipment when estimating facility-specific gas process utilization and by-product gas formation.

(2) You shall follow the QA/QC procedures in the EPA DRE measurement protocol when estimating abatement device DRE.

(3) You shall certify that abatement devices are maintained in accordance with manufacturer specified guidelines.

(4) You shall certify that gas consumption is tracked to a high degree of precision as part of normal facility operations and that further QA/QC is not required.

(f) You shall adhere to the QA/QC procedures of this paragraph when estimating F-GHG emissions from heat transfer fluid use:

(1) You shall review all inputs to Equation I-4 of this section to ensure that all inputs and outputs to the facility's system are accounted for.

(2) You shall not enter negative inputs into the mass balance Equation I-4 of this section and shall ensure that no negative emissions are calculated.

(3) You shall ensure that the beginning of year inventory matches the end of year inventory from previous year.

(g) All flowmeters, scales, load cells, and volumetric and density measures used to measure quantities that are to be reported under § 98.92 and § 98.96 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(h) All instruments (e.g., mass spectrometers and fourier transform infrared measuring systems) used to determine the concentration of fluorinated greenhouse gases in process streams shall be calibrated just prior to DRE, gas utilization, or product formation measurement through analysis of certified standards with known concentrations of the same chemicals in the same ranges (fractions by mass) as the process samples.

Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Test Method 205, 40 CFR Part 51, Appendix M may also be used.

§ 98.95 Procedures for estimating missing data.

(a) For semiconductor facilities that have an annual capacity of greater than 10,500 m² silicon, you shall estimate missing site-specific gas process utilization and by-product formation using default factors from Tables I-2 through I-4 of this subpart. However, use of these default factors shall be restricted to less than 5 percent of the total facility emissions.

(b) For facilities using heat transfer fluids and missing data for one or more of the parameters in Equation I-8, you shall estimate heat transfer fluid emissions using the arithmetic average of the emission rates for the year immediately preceding the period of missing data and the months immediately following the period of missing data. Alternatively, you may estimate missing information using records from the heat transfer fluid supplier. You shall document the method used and values estimated for all missing data values.

(c) If the methods specified in paragraphs (a) and (b) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing (e.g., because the monitoring failure was linked to a process disturbance that is likely to have significantly increased the F-GHG emission rate), you shall develop a best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in paragraphs (a) and (b) of this section would lead to a significant under- or overestimate of the parameter.

§ 98.96 Data reporting requirements.

In addition to the information required by § 98.3(c), you shall include in each annual report the following information for each electronics manufacturer.

(a) Emissions of each GHG emitted from all plasma etching processes, all chamber cleaning, all chemical vapor deposition processes, and all heat transfer fluid use, respectively.

(b) The method, mass of input F-GHG gases, and emission factors used for estimating F-GHG emissions.

(c) Production in terms of substrate surface area (e.g., silicon, PV-cell, LCD).

(d) Factors used for gas process utilization and by-product formation, and the source and uncertainty for each factor.

(e) The verified DRE and its uncertainty for each abatement device used, if you have verified the DRE pursuant to § 98.94(c).

² Most process tools have multiple chambers. For combustion-type abatement systems, the outlets of each chamber separately enter the destruction-reactor because premixing of certain gaseous mixtures may be conducive to fire or explosion. For the less-frequently used plasma-type POU abatement systems, there is one system per chamber.

- (f) Fraction of each gas fed into each process type with abatement devices.
- (g) Description of abatement devices, including the number of devices of each manufacturer and model.
- (h) For heat transfer fluid emissions, inputs in the mass-balance Equation.
- (i) Example calculations for F-GHG, N₂O, and heat transfer fluid emissions.
- (j) Estimate of the overall uncertainty in the emissions estimate.

§ 98.97 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:
 (a) Data used to estimate emissions including all spreadsheets and copies of calculations used to estimate emissions.

- (b) Documentation for the values used for GHG utilization rates and by-product emission factors, including documentation that these were measured using the the International SEMATECH Manufacturing Initiative's Guideline for Environmental Characterization of Semiconductor Process Equipment.
- (c) The date and results of the initial and any subsequent tests of emission control device DRE, including the following information:
 - (1) Dated certification, by the technician who made the measurement, that the dilution factor was determined using the tracer method.
 - (2) Dated certification, by the technician who made the measurement,

- that the DRE was calculated using the formula given in § 98.94(c)(1)(iv).
- (3) Documentation of the measured flows, concentrations and calculations used to calculate DF, relative precision (ε), and DRE.
- (d) The date and results of the initial and any subsequent tests to determine process tool gas utilization and by-product formation factors.
- (e) Abatement device calibration and maintenance records.

§ 98.98 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE I-1 OF SUBPART I—GHGS TYPICALLY USED BY THE ELECTRONICS INDUSTRY

Product type	F-GHGs Used during manufacture
Electronics	CF ₄ , C ₂ F ₆ , C ₃ F ₈ , c-C ₄ F ₈ , c-C ₄ F ₈ O, C ₄ F ₆ , C ₅ F ₈ , CHF ₃ , CH ₂ F ₂ , NF ₃ , SF ₆ , and HTFs (CF ₃ -(O-CF(CF ₃)-CF ₂) _n -(O-CF ₂) _m -O-CF ₃ , C _n F _{2n+2} , C _n F _{2n+1} (O)C _m F _{2m+1} , C _n F _{2n} O, (C _n F _{2n+1}) ₃ N)

TABLE I-2 OF SUBPART I—DEFAULT EMISSION FACTORS FOR SEMICONDUCTOR AND MEMS MANUFACTURING

Process gases	Factors					
	Etch 1-Ui	CVD 1-Ui	Etch BCF ₄	Etch BC ₂ F ₆	CVD BCF ₄	CVD BC ₃ F ₈
CF ₄	0.7	0.9	NA	NA	NA	NA
C ₂ F ₆	0.4*	0.6	0.4*	NA	0.1	NA
CHF ₃	0.4*	NA	0.07*	NA	NA	NA
CH ₂ F ₂	0.06*	NA	0.08*	NA	NA	NA
C ₃ F ₈	NA	0.4	NA	NA	0.1	NA
c-C ₄ F ₈	0.2*	0.1	0.2	0.2	0.1	NA
NF ₃	NA	0.02	NA	NA	†0.02	NA
Remote						
NF ₃	0.2	0.2	NA	NA	†0.1	NA
SF ₆	0.2	NA	NA	NA	NA	NA
C ₄ F ₆ ^a	0.1	NA	0.3*	0.2*	NA	NA
C ₅ F ₈ ^a	0.2	0.1	0.2	0.2	0.1	NA
C ₄ F ₈ O ^a	NA	0.1	NA	NA	0.1	0.4

Notes: NA denotes not applicable based on currently available information.
 * Estimate includes multi-gas etch processes.
 † Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing FC additive.

TABLE I-3 OF SUBPART I—DEFAULT EMISSION FACTORS FOR LCD MANUFACTURING

Process gases	Factors				
	Etch 1-Ui	CVD 1-Ui	Etch BCF ₄	Etch BCF ₃	Etch BC ₂ F ₆
CF ₄	0.6	NA	NA	NA	NA
C ₂ F ₆	NA	NA	NA	NA	NA
CHF ₃	0.2	NA	0.07	NA	0.05
CH ₂ F ₂	NA	NA	NA	NA	NA
C ₃ F ₈	NA	NA	NA	NA	NA
c-C ₄ F ₈	0.1	NA	0.009	0.02	NA
NF ₃ Remote	NA	0.03	NA	NA	NA
NF ₃	NA	0.3	NA	NA	NA
SF ₆	0.3	0.9	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

TABLE I-4 OF SUBPART I—DEFAULT EMISSION FACTORS FOR PV MANUFACTURING

Process gases	Factors				
	Etch 1-U _i	CVD 1-U _i	Etch BCF ₄	Etch BC ₂ F ₆	CVD BCF ₄
CF ₄	0.7	NA	NA	NA	NA
C ₂ F ₆	0.4	0.6	0.2	NA	0.2
CHF ₃	0.4	NA	NA	NA	NA
CH ₂ F ₂	NA	NA	NA	NA	NA
C ₃ F ₈	NA	0.1	NA	NA	0.2
c-C ₄ F ₈	0.2	0.1	0.1	0.1	0.1
NF ₃ Remote	NA	NA	NA	NA	NA
NF ₃	NA	0.3	NA	NA	NA
SF ₆	0.4	0.4	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Subpart J—Ethanol Production

§ 98.100 Definition of the source category.

An ethanol production facility is a facility that produces ethanol from the fermentation of sugar, starch, grain, or cellulosic biomass feedstocks; or produces ethanol synthetically from ethylene or hydrogen and carbon monoxide.

§ 98.101 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an ethanol production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.102 GHGs to report.

You must report:

(a) Emissions of CO₂, N₂O, and CH₄ from on-site stationary combustion. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(b) Emissions of CH₄ from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(c) Emissions of CH₄ from on-site wastewater treatment. You must follow

the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart II of this part.

§ 98.103 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

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.

(a) You must report the CO₂ emissions from each electric arc furnace used for ferroalloy production.

(b) You must report the CH₄ emissions from each electric arc furnace used for

the production of any ferroalloy listed in Table K-1 of this subpart.

(c) You must report the CO₂, CH₄, and N₂O emissions from each stationary combustion unit following the requirements specified in subpart C of this part.

§ 98.113 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements in subpart C of this part, you must estimate total CO₂ emissions according to the requirements in § 98.33.

(b) If you do not operate and maintain a CEMS that measures total CO₂ process emissions consistent with the requirements in subpart C, you must determine using the procedure specified in paragraphs (b)(1) and (2) of this section the total CO₂ emissions from all electric arc furnaces that are used for ferroalloy production.

(1) For each EAF at your facility used for ferroalloy production, you must determine the mass of carbon in each carbon-containing input and output material for the electric arc furnace for each calendar month using Equation K-1 of this section. Carbon containing input materials include carbon electrodes and carbonaceous reducing agents.

$$\begin{aligned}
 E_{CO_2} = & \frac{44}{12} \times \sum_{n=1}^{12} \left(\sum_i M_{\text{reducing agent}_i} \times C_{\text{reducing agent}_i} \right)_n \\
 & + \frac{44}{12} \times \sum_{n=1}^{12} \left(\sum_m M_{\text{electrode}_m} \times C_{\text{electrode}_m} \right)_n \\
 & + \frac{44}{12} \times \sum_{n=1}^{12} \left(\sum_h M_{\text{ore}_h} \times C_{\text{ore}_h} \right)_n \\
 & + \frac{44}{12} \times \sum_{n=1}^{12} \left(\sum_j M_{\text{flux}_j} \times C_{\text{flux}_j} \right)_n \\
 & - \frac{44}{12} \times \sum_{n=1}^{12} \left(\sum_k M_{\text{product}_k} \times C_{\text{product}_k} \right)_n \\
 & - \frac{44}{12} \times \sum_{n=1}^{12} \left(\sum_l M_{\text{non-product outgoing}_l} \times C_{\text{non-product outgoing}_l} \right)_n
 \end{aligned}
 \tag{Eq. K-1}$$

Where:

E_{CO_2} = Annual CO₂ mass emissions from an individual EAF, metric tons.

$M_{\text{reducing agent}_i}$ = Mass of reducing agent i fed, charged, or otherwise introduced into the EAF, metric tons.

$C_{\text{reducing agent}_i}$ = Carbon content in reducing agent i, metric tons of C/metric ton reducing agent.

$M_{\text{electrode}_m}$ = Mass of carbon electrode m consumed in the EAF, metric tons.

$C_{\text{electrode}_m}$ = Carbon content of the carbon electrode m, percent by weight, expressed as a decimal fraction.

M_{ore_h} = Mass of ore h charged to the EAF, metric tons.

C_{ore_h} = Carbon content in ore h, metric tons of C/metric ton ore.

M_{flux_j} = Mass of flux material j fed, charged, or otherwise introduced into the EAF to facilitate slag formation, metric tons.

C_{flux_j} = Carbon content in flux material j, metric tons of C/metric ton material.

M_{product_k} = Mass of alloy product k tapped from EAF, metric tons.

C_{product_k} = Carbon content in alloy product k, metric tons of C/metric ton product.

$M_{\text{non-product outgoing}_l}$ = Mass of non-product outgoing material l removed from EAF, metric tons.

$C_{\text{non-product outgoing}_l}$ = Carbon content in non-product outgoing material l, metric tons of C/metric ton.

(2) You must determine the total CO₂ emissions from the electric arc furnaces using Equation K-2 of this section:

$$CO_2 = \sum_1^k E_{CO_2k} \tag{Eq. K-2}$$

Where:

CO_2 = Total annual CO₂ emissions, metric tons/year.

E_{CO_2k} = Annual CO₂ emissions calculated using Equation K-1 of this subpart, metric tons/year.

k = Total number of EAFs at facility used for the ferroalloy production.

(c) For the electric arc furnaces used at your facility for the production of any ferroalloy listed in Table K-1 of this subpart, you must determine the total

CH₄ emissions using the procedure specified in paragraphs (c)(1) and (2) of this section.

(1) For each EAF, calculate annual CH₄ emissions using Equation K-3 of this section:

$$E_{CH_4} = \sum_1^i (M_{\text{product}_i} \times EF_{\text{product}_i}) \tag{Eq. K-3}$$

Where:

E_{CH_4} = Annual CH₄ emissions from an individual EAF, metric tons.

M_{product_i} = Annual mass of alloy product i produced in the EAF, metric tons.

EF_{product_i} = CH₄ emission factor for alloy product i from Table K-1 of this subpart, kg of CH₄ emissions per metric ton of alloy product i.

(2) You must determine the total CH₄ emissions using Equation K-4 of this section:

$$CH_4 = \sum_1^j E_{CH_4j} \tag{Eq. K-4}$$

Where:

CH_4 = Total annual CH₄ emissions, metric tons/year.

E_{CH_4j} = Annual CH₄ emissions from EAF k calculated using Equation K-3 of this section, metric tons/year.

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 CO₂ emissions using the carbon balance procedure in § 98.113(b), you must meet the requirements specified in paragraphs (a) through (c) of this section.

(a) Determine the mass of each solid carbon-containing process input and output material by direct measurements or calculations using process operating information, and record the total mass

of each material consumed or produced for each calendar month.

(b) For each process input and output material identified in paragraph (a) of this section, you must determine the average carbon content of the material for the specified period using information provided by your material supplier or by collecting and analyzing a representative sample of the material.

(c) For each input material identified in paragraph (a) of this section for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed by an independent certified laboratory at least annually using the test methods (and their QA/QC procedures) in § 98.7. Use ASTM E1941-04 (“Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys”) for analysis of metal ore and alloy product; ASTM D5373-02 (“Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke”) for analysis of carbonaceous reducing agents and carbon electrodes, and ASTM C25-06 (“Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”) for analysis of flux materials such as limestone or dolomite.

§ 98.115 Procedures for estimating missing data.

For the carbon input procedure in § 98.113(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.

(a) For each missing value of the carbon 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, 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 records of the mass of carbon-containing input or output material consumption, the substitute data value shall be the best available estimate of the mass of the input or output material. The owner or operator shall document and keep records of the procedures used for all such estimates.

(c) If you are required to calculate CH₄ emissions for the electric arc furnace as specified in § 98.113(c), then you are required to have 100 percent of the specified data for each reporting period.

§ 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 (f) of this section.

(a) Annual CO₂ emissions from each electric arc furnace used for ferroalloy production, in metric tons and the method used to estimate these emissions.

(b) Annual CH₄ emissions from each electric arc furnace used for the production of any ferroalloy listed in Table K-1 of this subpart.

(c) Facility ferroalloy product production capacity (metric tons).

(d) Annual facility production quantity for each ferroalloy product (metric tons).

(e) Number of facility operating hours in calendar year.

(f) If you use the carbon balance procedure, report for each carbon-containing input and output material consumed or used (other than fuel), the information specified in paragraphs (g)(1) and (2) of this section.

(1) Annual material quantity (in metric tons).

(2) Annual average of the monthly carbon content determinations for each material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).

§ 98.117 Records that must be retained.

In addition to the records required by § 98.3(g) of this part, you must retain the records specified in paragraphs (a) through (e) of this section.

(a) Monthly facility production quantity for each ferroalloy product (in metric tons).

(b) Number of facility operating hours each month.

(c) If you use the carbon balance procedure, record for each carbon-containing input and output material consumed or used (other than fuel), the information specified in paragraphs (c)(1) and (2) of this section.

(1) Monthly material quantity (in metric tons).

(2) Monthly average carbon content determined for material and records of the supplier provided information or analyses used for the determination.

(d) 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 electric arc furnace. 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.

(e) If you are required to calculate CH₄ emissions for the electric arc furnace as specified in § 98.113(c), 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 CH₄ emissions.

§ 98.118 Definitions.

All terms used in 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

TABLE K-1 OF SUBPART K—ELECTRIC ARC FURNACE (EAF) CH₄ EMISSION FACTORS—Continued

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
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—Fluorinated Greenhouse Gas Production

§ 98.120 Definition of the source category.

The fluorinated gas production source category consists of facilities that produce a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHG does not include the reuse or recycling of a fluorinated GHG or the generation of HFC-23 during the production of HCFC-22.

§ 98.121 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a fluorinated greenhouse gas production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.122 GHGs to report.

(a) You must report the CO₂, N₂O, and CH₄ emissions from each on-site stationary combustion unit. For these stationary combustion units, you must follow the applicable calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(b) You must report the total mass of each fluorinated GHG emitted from each fluorinated GHG production process and from all fluorinated GHG production processes at the facility.

§ 98.123 Calculating GHG emissions.

(a) The total mass of each fluorinated GHG product emitted annually from all fluorinated GHG production processes shall be estimated by using Equation L-1 of this section:

$$E_p = \sum_{p=1}^n \sum_{i=1}^m E_{pip} \quad (\text{Eq. L-1})$$

Where:

- E_p = Total mass of each fluorinated GHG product emitted annually from all production processes (metric tons).
- E_{pip} = Total mass of the fluorinated GHG product emitted from production process i over the period p (metric tons, defined in Equation L-3 of this section).
- n = Number of concentration and flow measurement periods for the year.
- m = Number of production processes.

(b) The total mass of fluorinated GHG by-product k emitted annually from all fluorinated GHG production processes shall be estimated by using Equation L-2 of this section:

$$E_{Bk} = \sum_{p=1}^n \sum_{i=1}^m E_{Bkip} \quad (\text{Eq. L-2})$$

Where:

- E_{Bk} = Total mass of fluorinated GHG by-product k emitted annually from all production processes (metric tons).
- E_{Bkip} = Total mass of fluorinated GHG by-product k emitted from production process i over the period p (metric tons, defined in Equation L-8 on this section).
- n = Number of concentration and flow measurement periods for the year.
- m = Number of production processes.

(c) The total mass of each fluorinated GHG product emitted from production process i over the period p shall be estimated at least daily by calculating the difference between the expected production of the fluorinated GHG based on the consumption of reactants (e.g., HF and a chlorocarbon reactant) and the measured production of the fluorinated GHG, accounting for yield losses related to by-products and wastes. This calculation shall be performed for each reactant, using Equation L-3 of this section. Estimated emissions shall equal the average of the results obtained for each reactant.

$$E_{pip} = \frac{R * MW_p * SC_p}{MW_R * SC_R} - P - \sum_{j=1}^q (C_p * W_{Dj}) - \sum_{k=1}^u L_{Bkip} \quad (\text{Eq. L-3})$$

Where:

- E_{pip} = Total mass of each fluorinated GHG product emitted from production process i over the period p (metric tons).
- P = Total mass of the fluorinated GHG produced by production process i over the period p (metric tons).
- R = Total mass of the reactant that is consumed by production process i over the period p (metric tons, defined in Equation L-4).
- MW_R = Molecular weight of the reactant.
- MW_p = Molecular weight of the fluorinated GHG produced.
- SC_R = Stoichiometric coefficient of the reactant.

- SC_p = Stoichiometric coefficient of the fluorinated GHG produced.
- C_p = Concentration (mass fraction) of the fluorinated GHG product in stream j of destroyed wastes. If this concentration is only a trace concentration, C_p is equal to zero.
- W_{Dj} = Mass of wastes removed from production process i in stream j and destroyed over the period p (metric tons, defined in Equation L-5 of this section).
- L_{Bkip} = Yield loss related to by-product k for production process i over the period p (metric tons, defined in Equation L-6 of this section).
- q = Number of waste streams destroyed in production process i.

- u = Number of by-products generated in production process i.

(d) The total mass of the reactant that is consumed by production process i over the period p shall be estimated by using Equation L-4 of this section:

$$R = R_F - R_R \quad (\text{Eq. L-4})$$

Where:

- R = Total mass of the reactant that is consumed by production process i over the period p (metric tons).
- R_F = Total mass of the reactant that is fed into production process i over the period p (metric tons).

R_R = Total mass of the reactant that is permanently removed from production process i over the period p (metric tons).

(e) The mass of wastes removed from production process i in stream j and destroyed over the period p shall be estimated using Equation L-5 of this section:

$$W_{Dj} = W_{Fj} * DE \quad (\text{Eq. L-5})$$

Where:

W_{Dj} = The mass of wastes removed from production process i in stream j and destroyed over the period p (metric tons).

W_{Fj} = The total mass of wastes removed from production process i in stream j and fed

into the destruction device over the period p (metric tons).
DE = Destruction Efficiency of the destruction device (fraction).

(f) Yield loss related to by-product k for production process i over period p shall be estimated using Equation L-6 of this section:

$$L_{Bkip} = \frac{(B_{kip} * MW_P * ME_{Bk})}{(MW_{Bk} * ME_p)} \quad (\text{Eq. L-6})$$

Where:

L_{Bkip} = Yield loss related to by-product k for production process i over the period p (metric tons).

B_{kip} = Mass of by-product k generated by production process i over the period p (metric tons, defined in Equation L-7 of this section).

MW_P = Molecular weight of the fluorinated GHG produced.

MW_{Bk} = Molecular weight of by-product k.
 ME_{Bk} = Moles of the element shared by the reactant, product, and by-product k per mole of by-product k.

ME_P = Moles of the element shared by the reactant, product, and by-product k per mole of the product.

(g) If by-product k is responsible for yield loss in production process i and

occurs in any process stream in more than trace concentrations, the mass of by-product k generated by production process i over the period p shall be estimated using Equation L-7 of this section:

$$B_{kip} = \sum_j^q c_{Bjk} * S_j \quad (\text{Eq. L-7})$$

Where:

B_{kip} = Mass of by-product k generated by production process i over the period p (metric tons).

C_{Bkj} = Concentration (mass fraction) of the by-product k in stream j of production process i over the period p. If this

concentration is only a trace concentration, C_{Bkj} is equal to zero.

S_j = Mass flow of process stream j of production process i over the period p.
q = Number of streams in production process i.

(h) If by-product k is responsible for yield loss, is a fluorinated GHG, occurs in any process stream in more than trace concentrations, and is not completely recaptured or completely destroyed; the total mass of by-product k emitted from production process i over the period p shall be estimated at least daily using Equation L-8 of this section:

$$E_{Bkip} = B_{kip} - \sum_{j=1}^q c_{Bkj} * W_{Dj} - \sum_{l=1}^v c_{Bkl} * S_{Rl} \quad (\text{Eq. L-8})$$

Where:

E_{Bkip} = Mass of by-product k emitted from production process i over the period p (metric tons).

B_{kip} = Mass of by-product k generated by production process i over the period p (metric tons).

C_{Bkj} = Concentration (mass fraction) of the by-product k in stream j of destroyed wastes over the period p. If this concentration is only a trace concentration, C_{Bkj} is equal to zero.

W_{Dj} = The mass of wastes that are removed from production process i in stream j and that are destroyed over the period p (metric tons, defined in Equation L-5 of this section).

C_{Bkl} = The concentration (mass fraction) of the by-product k in stream l of recaptured material over the period p. If this concentration is only a trace concentration, C_{Bkl} is equal to zero.

S_{Rl} = The mass of materials that are removed from production process i in stream l and that are recaptured over the period p.

q = Number of waste streams destroyed in production process i.

v = Number of streams recaptured in production process i.

§ 98.124 Monitoring and QA/QC requirements.

(a) The total mass of fluorinated GHGs produced over the period p shall be estimated at least daily using the methods and measurements set forth in §§ 98.413(b) and 98.414.

(b) The total mass of each reactant fed into the production process shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(c) The total mass of each reactant permanently removed from the production process shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the reactant, the concentration of the reactant shall be measured at least daily 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 reactant permanently removed from the production process.

(d) If the waste permanently removed from the production process and fed into the destruction device contains more than trace concentrations of the fluorinated GHG product, the mass of waste fed into the destruction device shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the product, the concentration of the product shall be measured at least daily 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.

(e) If a by-product is responsible for yield loss and occurs in any process stream in more than trace concentrations, the mass flow of each process stream that contains more than trace concentrations of the by-product shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the by-product, the concentration of the by-product shall be measured at least daily 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.

(f) If a by-product is a fluorinated GHG, occurs in more than trace concentrations in any process stream, occurs in more than trace concentrations in any stream that is recaptured or is fed into a destruction device, and is not completely recaptured or completely destroyed; the mass flow of each stream that contains more than trace concentrations of the by-product and that is recaptured or is fed into the destruction device or shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the by-product, the concentration of the by-product shall be measured at least daily 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.

(g) All flowmeters, scales, load cells, and volumetric and density measures used to measure quantities that are to be reported under § 98.126 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(h) All gas chromatographs used to determine the concentration of fluorinated greenhouse gases in process streams shall be calibrated at least

monthly through analysis of certified standards with known concentrations of the same chemicals in the same ranges (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Test Method 205, 40 CFR Part 51, Appendix M may also be used.

(i) For purposes of equation L-5, the destruction efficiency can initially 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. Fluorinated GHG production facilities that destroy fluorinated GHGs shall conduct annual measurements of mass flow and fluorinated GHG concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6. Tests shall be conducted under conditions that are typical for the production process and destruction device at the facility. The sensitivity of the emissions tests shall be sufficient to detect emissions equal to 0.01 percent of the mass of fluorinated GHGs being fed into the destruction device. If the test indicates that the actual DE of the destruction device is lower than the previously determined DE, facilities shall either:

(1) Substitute the DE implied by the most recent emissions test for the previously determined DE in the calculations in § 98.123, or

(2) Perform more extensive performance testing of the DE of the oxidizer and use the DE determined by the more extensive testing in the calculations in § 98.123.

(j) 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.

(k) Fluorinated GHG production facilities shall account for fluorinated GHG emissions that occur as a result of startups, shutdowns, and malfunctions, either recording fluorinated GHG emissions during these events, or documenting that these events do not result in significant fluorinated GHG emissions.

§ 98.125 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 mass of fluorinated GHG produced, the mass of reactants fed into the production process, the mass of reactants permanently removed from the production process, the mass flow of process streams containing more than trace concentrations of by-products that lead to yield losses, or the mass of wastes fed into the destruction device; the substitute value of that parameter shall be a secondary mass measurement taken during the period the primary mass measurement was not 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.

(2) For each missing value of fluorinated GHG 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 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.

(3) If the methods specified in paragraphs (a)(1) and (2) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing, you shall develop a best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in (a)(1) and (2) would lead to a significant under- or overestimate of the parameter.

§ 98.126 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), you shall report the following information for each production process at the facility.

(1) The total mass of the fluorinated GHG produced in metric tons, by chemical.

(2) The total mass of each reactant fed into the production process in metric tons, by chemical.

(3) The total mass of each reactant permanently removed from the production process in metric tons, by chemical.

(4) The total mass of the fluorinated GHG product removed from the production process and destroyed.

(5) The mass of each by-product generated.

(6) The mass of each by-product destroyed at the facility.

(7) The mass of each by-product recaptured and sent off-site for destruction.

(8) The mass of each by-product recaptured for other purposes.

(9) The mass of each fluorinated GHG emitted.

(b) Where missing data have been estimated pursuant to § 98.125, you shall report the information specified in paragraphs (b)(1) and (2) of this section.

(1) 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.

(2) Where the missing data have been estimated pursuant to § 98.125(a)(3), you shall also report the rationale for the methods used to estimate the missing data and why the methods specified in § 98.125 (a)(1) and (2) would lead to a significant under- or overestimate of the parameter(s).

(c) A fluorinated GHG production facility that destroys fluorinated GHGs shall report the results of the annual fluorinated GHG concentration measurements at the outlet of the destruction device, including:

(1) Flow rate of fluorinated GHG being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of fluorinated GHG at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(4) Emission rate calculated from paragraphs(c)(2) and (c)(3) of this section in kg/hr.

(d) A fluorinated GHG production facility that destroys fluorinated GHGs shall submit a one-time report containing the following information:

(1) Destruction efficiency (DE) of each destruction unit.

(2) Test 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.

§ 98.127 Records that must be retained.

(a) In addition to the data required by §§ 98.123 and 98.126, you shall retain the following records:

(1) Dated records of the data used to estimate the data reported under §§ 98.123 and 98.126.

(2) Dated 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 § 98.124(g) and (h).

(b) In addition to the data required by paragraph (a) of this section, the designated representative of a 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 § 98.126(c) and (d).

§ 98.128 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart M—Food Processing

§ 98.130 Definition of the source category.

Food processing facilities prepare raw ingredients for consumption by animals or humans. Food processing facilities transform raw ingredients into food, transform food into other forms for consumption by humans or animals, or transform food for further processing by the food processing industry.

§ 98.131 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a food processing operation and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.132 GHGs to report.

You must report:

(a) Emissions of CO₂, N₂O, and CH₄ from on-site stationary combustion. You must follow the requirements of subpart C of this part.

(b) Emissions of CH₄ from on-site landfills. You must follow the

calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(c) Emissions of CH₄ from on-site wastewater treatment. You must follow the requirements of subpart II of this part.

§ 98.133 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

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.

(a) You must report CO₂ process emissions from each continuous glass melting furnace at your glass manufacturing facility as required by this subpart.

(b) You must report the CO₂, N₂O, and CH₄ emissions from fuel combustion at each continuous glass melting furnace and at any other on-site stationary fuel combustion unit. For each stationary fuel combustion unit, you must follow the requirements of subpart C of this part.

§ 98.143 Calculating GHG emissions.

(a) If you operate and maintain a continuous emission monitoring system (CEMS) that measures total CO₂ emissions consistent with the requirements in subpart C of this part, you must estimate total CO₂ emissions according to the requirements in § 98.33.

(b) If you do not operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements in subpart C of this part, you shall calculate process emissions of CO₂ from each glass melting furnace

according to paragraphs (b)(1) through

TABLE N-1 OF SUBPART N—CO₂ EMISSION FACTORS FOR CARBONATE-BASED RAW MATERIALS—Continued

Carbonate-based raw material—mineral	CO ₂ Emission factor ^a
Dolomite—CaMg(CO ₃) ₂	0.477
Sodium carbonate/soda ash—Na ₂ CO ₃	0.415

^aEmission 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 (2).

§ 98.152 GHGs to report.

(a) You must report the CO₂, N₂O, and CH₄ emissions from each on-site stationary combustion unit. For these stationary combustion units, you must follow the applicable calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(b) You must report HFC-23 emissions from HCFC-22 production processes and HFC-23 destruction processes.

§ 98.153 Calculating GHG emissions.

(a) The total 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 daily (or more frequent) HFC-23 concentration measurement (which may be the average of more frequent concentration measurements) by the daily (or more frequent) mass flow of the combined stream of HFC-23 and the other product. To estimate annual HFC-23 production, sum the daily (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:

- G₂₃ = Mass of HFC-23 generated annually (metric tons).
- c₂₃ = 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 daily (or more frequent) measurement of the HFC-23 concentration and the daily (or more frequent) measurement of the other product concentration by the daily (or more frequent) mass produced of the other product. To estimate annual HFC-23 production, sum the daily (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:

- G₂₃ = Mass of HFC-23 generated annually (metric tons).
- c₂₃ = Fraction HFC-23 by weight in HCFC-22/HFC-23 stream.
- c₂₂ = Fraction HCFC-22 by weight in HCFC-22/HFC-23 stream.
- P₂₂ = Mass of HCFC-22 produced over the period p (kg).
- 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:

- P₂₂ = Mass of HCFC-22 produced over the period p (kg).
- O₂₂ = mass of HCFC-22 that is measured coming out of the Production process over the period p (kg).
- U₂₂ = 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 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:

$$E_{23} = G_{23} - (S_{23} + OD_{23} + D_{23}) \quad (\text{Eq. O-4})$$

Where:

E₂₃ = Mass of HFC-23 emitted annually (metric tons).

G₂₃ = Mass of HFC-23 generated annually (metric tons).

S₂₃ = Mass of HFC-23 packaged for sale annually (metric tons).

OD₂₃ = Mass of HFC-23 sent off-site for destruction (metric tons).

D₂₃ = Mass of HFC-23 destroyed on-site (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 (metric tons).
- E_{PV} = Mass of HFC-23 emitted annually from process vents, calculated using Equation O-7 (metric tons).

E_D = Mass of HFC-23 emitted annually from thermal oxidizer (metric tons), calculated using Equation O-9 of this section.

(e) 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).
- 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 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(h).
- F_{Lt} = The applicable leak rate specified in table O-1 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(i).
- 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.
- 10^{-3} = Factor converting kg to metric tons.

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

(f) 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.

- D = 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).

(h) The total mass of HFC-23 emitted from destruction devices shall be estimated by using Equation O-9 of this section:

$$E_D = F_D - D \quad (\text{Eq. O-9})$$

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 = Mass of HFC-23 destroyed annually (metric tons).

§ 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 daily 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 continuously using a flow meter with an accuracy and precision of 1.0 percent of full scale or better.

(g) For facilities that destroy HFC-23, the total mass of HFC-23 destroyed shall be estimated by using Equation O-8 of this section:

$$D = F_D * DE \quad (\text{Eq. O-8})$$

Where:

(c) The mass of HCFC-22 or HCl coming out of the production process shall be measured at least daily 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 at least daily (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.

(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 packaged for sale shall be measured at least daily (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 daily (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 daily 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 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.

(i) 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.

(j) The mass of HFC-23 emitted from process vents shall be estimated at least monthly by conducting emissions tests at process vents at least annually and by incorporating the results of the most recent emissions test into Equation O-6 of this subpart. 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.

(k) For purposes of Equation O-8, the destruction efficiency can initially 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. HFC-23 destruction facilities shall conduct annual measurements of mass flow and HFC-23 concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6. Tests shall be conducted under conditions that are typical for the production process and destruction device at the facility. The sensitivity of the emissions tests shall be sufficient to detect emissions equal to 0.01 percent of the mass of HFC-23 being fed into the destruction device. If the test indicates that the actual DE of the destruction device is lower than the previously determined DE, facilities shall either:

(1) Substitute the DE implied by the most recent emissions test for the previously determined DE in the calculations in § 98.153.

(2) Perform more extensive performance testing of the DE of the oxidizer and use the DE determined by the more extensive testing in the calculations in § 98.153.

(l) Designated representatives of 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.

(m) The mass of HFC-23 fed into the destruction device shall be measured at

least daily 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 daily 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.

(n) In their estimates of the mass of HFC-23 destroyed, designated representatives of 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.

(o) All flowmeters, scales, and load cells used to measure quantities that are to be reported under § 98.156 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(p) 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 Test Method 205, 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. 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.

(3) Notwithstanding paragraphs (a)(1) and (2) of this section, if the owner or operator has reason to believe that the methods specified in paragraphs (a)(1) and (2) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing (e.g., because the monitoring failure was linked to a process disturbance that is likely to have significantly increased the HFC-23 generation rate), the designated representative of the HCFC-22 production facility shall develop his or her best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in (a)(1) and (2) would probably lead to a significant under- or overestimate of the parameter.

§ 98.156 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the designated representative of an HCFC-22 production facility shall report the following information at the facility level:

(1) The mass of HCFC-22 produced in metric tons.

(2) The mass of reactants fed into the process in metric tons of reactant.

(3) 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.

(4) The method for tracking startups, shutdowns, and malfunctions and HFC-

23 generation/emissions during these events.

(5) 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.

(6) The total mass of the HFC-23 generated in metric tons.

(7) The mass of any HFC-23 packaged for sale in metric tons.

(8) The mass of any HFC-23 sent off site for destruction in metric tons.

(9) The mass of HFC-23 emitted in metric tons.

(10) The mass of HFC-23 emitted from equipment leaks in metric tons.

(11) The mass of HFC-23 emitted from process vents in metric tons.

(b) Where missing data have been estimated pursuant to § 98.155, the designated representative of the HCFC-22 production facility or HFC-23 destruction facility shall report 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.

(1) Where the missing data have been estimated pursuant to § 98.155(a)(3), the designated representative shall also report the rationale for the methods used to estimate the missing data and why the methods specified in § 98.155(a)(1) and (2) would probably lead to a significant under- or overestimate of the parameter(s).

(c) In addition to the information required by § 98.3(c), the designated representative of a facility that destroys HFC-23 shall report the following for each HFC-23 destruction process:

(1) The mass of HFC-23 fed into the thermal oxidizer.

(2) The mass of HFC-23 destroyed.

(3) The mass of HFC-23 emitted from the thermal oxidizer.

(d) The designated representative of 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) The flow rate of HFC-23 being fed into the destruction device in kg/hr.

(2) The concentration (mass fraction) of HFC-23 at the outlet of the destruction device.

(3) The flow rate at the outlet of the destruction device in kg/hr.

(4) The emission rate calculated from paragraphs (c)(2) and (3) of this section in kg/hr.

(e) The designated representative of an HFC-23 destruction facility shall submit a one-time report including the following information:

(1) The destruction unit's destruction efficiency (DE).

(2) The methods used to determine the unit's 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), the designated representative of an HCFC-22 production facility 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(o) and (p).

(b) In addition to the data required by § 98.3(g), the designated representative of a HFC-23 destruction facility shall retain the following records:

(1) Records documenting their one-time and annual reports in § 98.156(c), (d), and (e).

(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 standards or manufacturer directions used for calibration pursuant to § 98.154(o) and (p).

§ 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.

Subpart P—Hydrogen Production

§ 98.160 Definition of the source category.

(a) A hydrogen production source category produces hydrogen gas that is consumed at sites other than where it is produced.

(b) This source category comprises process units that produce hydrogen by oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes hydrogen production facilities located within a petroleum refinery and that are not owned 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 (2).

§ 98.162 GHGs to report.

You must report:

- (a) CO₂ process emissions for each hydrogen production process unit.
 (b) CO₂, CH₄, and N₂O emissions from the combustion of fuels in each hydrogen production unit and any other stationary combustion units by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting

requirements, and recordkeeping requirements of subpart C of this part.

(c) For CO₂ collected and used on site or transferred off site, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart PP of this part.

§ 98.163 Calculating GHG emissions.

You must determine CO₂ emissions in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) *Continuous emission monitoring system.* Any hydrogen process unit that meets the conditions specified in

§ 98.33(b)(5)(iii)(A), (B), and (C), or § 98.33(b)(5)(ii)(A) through (F) shall calculate total CO₂ emissions using a continuous emissions monitoring system according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) *Feedstock material balance approach.* If you do not measure total emissions with a CEMS, you must calculate the annual CO₂ process emissions from feedstock used for hydrogen production.

(1) *Gaseous feedstock.* You must calculate the total CO₂ process emissions from gaseous 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 feedstock consumption (metric tons).

(Fdstk)_n = Volume of the gaseous feedstock used in month n (scf of feedstock).

(CC)_n = Average carbon content of the gaseous feedstock, from the analysis

results for month n (kg C per kg of feedstock).

MW = Molecular weight of the gaseous feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

k = Months per year.

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

0.001 = Conversion factor from kg to metric tons.

(2) *Liquid feedstock.* You must calculate the total CO₂ process emissions from liquid 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:

CO₂ = Annual CO₂ emissions arising from feedstock consumption (metric tons).

(Fdstk)_n = Volume of the liquid feedstock used in month n (gallons of feedstock).

(CC)_n = Average carbon content of the liquid feedstock, from the analysis results for month n (kg C per gallon of feedstock).

k = Months per year.

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

0.001 = Conversion factor from kg to metric tons.

(3) *Solid feedstock.* You must calculate the total CO₂ process emissions from solid 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 feedstock consumption in metric tons per month (metric tons).

(Fdstk)_n = Mass of solid feedstock used in month n (kg of feedstock).

(CC)_n = Average carbon content of the solid feedstock, from the analysis results for month n (kg C per kg of feedstock).

k = Months per year.

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

0.001 = Conversion factor from kg to metric tons.

§ 98.164 Monitoring and QA/QC requirements.

(a) Facilities that use CEMS must comply with the monitoring and QA/QC procedures specified in § 98.34(e).

(b) The quantity of gaseous or liquid feedstock consumed must be measured continuously using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(c) You must collect a sample of each feedstock and analyze the carbon content of each sample using

appropriate test methods incorporated by reference in § 98.7. The minimum frequency of the fuel sampling and analysis is monthly.

(d) All fuel flow meters, gas composition monitors, and heating value monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow

meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(e) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

§ 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 shall be used in the calculations, according to the following requirements:

(a) For missing feedstock supply rates, use the lesser of the maximum supply rate that the unit is capable of processing or the maximum supply rate that the meter can measure.

(b) There are no missing data procedures for carbon content. A re-test must be performed if the data from any monthly measurements are determined to be invalid.

(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 following information for each process unit:

(a) Facilities that use CEMS must comply with the procedures specified in § 98.36(a)(1)(iv).

(b) Annual total consumption of feedstock for hydrogen production; annual total of hydrogen produced; and annual total of ammonia produced, if applicable.

(c) Monthly analyses of carbon content for each feedstock used in hydrogen production (kg carbon/kg of feedstock).

§ 98.167 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) For all CEMS, you must comply with the CEMS recordkeeping requirements in § 98.37.

(b) Monthly analyses of carbon content for each feedstock used in hydrogen production.

§ 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 combustion-related CO₂, CH₄, and N₂O emissions from each stationary combustion unit and follow the requirements in subpart C of this part. Stationary combustion units include, but are not limited to, by-

product recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheater furnaces, annealing furnaces, flares, flame suppression, ladle reheaters, and other miscellaneous combustion sources.

(b) You must report process-related CO₂ emissions from each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery combustion stack; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace by following the procedures in this subpart.

(c) You must report CO₂ emissions from each coke pushing process by following the procedures in this subpart.

§ 98.173 Calculating GHG emissions.

(a) For each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, and direct reduction furnace, you must determine CO₂ emissions using the procedures in paragraph (a)(1), (a)(2), or (3) of this section as appropriate.

(1) Continuous emissions monitoring system (CEMS). If you operate and maintain a CEMS that measures CO₂ emissions consistent with the requirements in subpart C, you must estimate total CO₂ emissions according to the requirements in § 98.33.

(2) *Carbon mass balance method*. For the carbon balance method, calculate the mass emissions rate of CO₂ in each calendar month for each process as specified in paragraphs (a)(2)(i) through (vii) of this section. The calculations are based on the monthly mass of inputs and outputs to each process and the respective weight fraction of carbon. If you have a process input or output that contains carbon that is not included in the Equations, you must account for the carbon and mass rate of that process input or output in your calculations.

(i) For taconite indurating furnaces, estimate CO₂ emissions using Equation Q-1 of this section.

$$CO_2 = \sum_1^{12} \frac{44}{12} * \left[(F_s)_n * (C_{sf})_n + (F_g)_n * (C_{gf})_n * \frac{MW}{MVC} * 0.001 + (F_l)_n * (C_{lf})_n * 0.001 + (O)_n * (C_o) - (P)_n * (C_p)_n \right] \quad (\text{Eq. Q-1})$$

Where:

CO₂ = Annual CO₂ mass emissions from the indurating furnace (metric tons).

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

(F_s)_n = Mass of the solid fuel combusted in month "n" (metric tons).

(C_{sf})_n = Carbon content of the solid fuel, from the fuel analysis results for month "n"

(percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

(F_g)_n = Volume of the gaseous fuel combusted in month "n" (scf).

(C_{gf})_n = Average carbon content of the gaseous fuel, from the fuel analysis

results for month "n" (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)_n = Volume of the liquid fuel combusted in month “n” (gallons).
 (C_{fl})_n = Carbon content of the liquid fuel, from the fuel analysis results for month “n” (kg C per gallon of fuel).
 (O)_n = Mass of greenball (taconite) pellets fed to the furnace in month “n” (metric tons).

(C_o)_n = Carbon content of the greenball (taconite) pellets, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).
 (P)_n = Mass of fired pellets produced by the furnace in month “n” (metric tons).

(C_p)_n = Carbon content of the fired pellets, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(ii) For basic oxygen process furnaces, estimate CO₂ emissions using Equation Q-2 of this section.

$$CO_2 = \sum_1^{12} \frac{44}{12} * \left[(Iron)_n * (C_{Iron})_n + (Scrap)_n * (C_{Scrap})_n + (Flux)_n * (C_{Flux})_n + (Carbon)_n * (C_{Carbon})_n - (Steel)_n * (C_{Steel})_n - (Slag)_n * (C_{Slag})_n \right] \quad (\text{Eq. Q-2})$$

Where:

CO₂ = Annual CO₂ mass emissions from the basic oxygen furnace (metric tons).

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

(Iron)_n = Mass of molten iron charged to the furnace in month “n” (metric tons).

(C_{Iron})_n = Carbon content of the molten iron, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Scrap)_n = Mass of ferrous scrap charged to the furnace in month “n” (metric tons).

(C_{Scrap})_n = Average carbon content of the ferrous scrap, from the carbon analysis

results for month “n” (percent by weight, expressed as a decimal fraction).

(Flux)_n = Mass of flux materials (e.g., limestone, dolomite) charged to the furnace in month “n” (metric tons).

(C_{Flux})_n = Average carbon content of the flux materials, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Carbon)_n = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month “n” (metric tons).

(C_{Carbon})_n = Average carbon content of the carbonaceous materials, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Steel)_n = Mass of molten steel produced by the furnace in month “n” (metric tons).

(C_{Steel})_n = Average carbon content of the steel, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Slag)_n = Mass of slag produced by the furnace in month “n” (metric tons).

(C_{Slag})_n = Average carbon content of the slag, from the carbon analysis results for month “n” (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.

$$CO_2 = \sum_1^{12} \frac{44}{12} * \left[(Coal)_n * (C_{Coal})_n - (Coke)_n * (C_{Coke})_n \right] \quad (\text{Eq. Q-3})$$

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)_n = Mass of coal charged to the battery in month “n” (metric tons).

(C_{Coal})_n = Carbon content of the coal, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Coke)_n = Mass of coke produced by the battery in month “n” (metric tons).

(C_{Coke})_n = Carbon content of the coke, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(iv) For sinter processes, estimate CO₂ emissions using Equation Q-4 of this section.

$$CO_2 = \sum_1^{12} \frac{44}{12} * \left[(F_g)_n * (C_{gf})_n * \frac{MW}{MVC} * 0.001 + (Feed)_n * (C_{Feed}) - (Sinter)_n * (C_{Sinter})_n \right] \quad (\text{Eq. Q-4})$$

Where:

CO₂ = Annual CO₂ mass emissions from the sinter process (metric tons).

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

(F_g)_n = Volume of the gaseous fuel combusted in month “n” (scf).

(C_{gf})_n = Average carbon content of the gaseous fuel, from the fuel analysis results for month “n” (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)_n = Mass of sinter feed material in month “n” (metric tons).

(C_{Feed})_n = Carbon content of the sinter feed material, from the carbon analysis results

for month “n” (percent by weight, expressed as a decimal fraction).

(Sinter)_n = Mass of sinter produced in month “n” (metric tons).

(C_{Sinter})_n = Carbon content of the sinter pellets, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(v) For EAFs, estimate CO₂ emissions using Equation Q-5 of this section.

$$CO_2 = \sum_1^{12} \frac{44}{12} * [(Iron)_n * (C_{Iron})_n + (Scrap)_n * (C_{Scrap})_n + (Flux)_n * (C_f)_n + (Electrode)_n * (C_{Electrode})_n + (Carbon)_n * (C_C) - (Steel)_n * (C_{Steel})_n - (Slag)_n * (C_{Slag})_n] \quad (\text{Eq. Q-5})$$

Where:

CO₂ = Annual CO₂ mass emissions from the EAF (metric tons).

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

(Iron)_n = Mass of direct reduced iron (if any) charged to the furnace in month “n” (metric tons).

(C_{Iron})_n = Carbon content of the molten iron, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Scrap)_n = Mass of ferrous scrap charged to the furnace in month “n” (metric tons).

(C_{Scrap})_n = Average carbon content of the ferrous scrap, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Flux)_n = Mass of flux materials (e.g., limestone, dolomite) charged to the furnace in month “n” (metric tons).

(C_{Flux})_n = Average carbon content of the flux materials, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Electrode)_n = Mass of carbon electrode consumed in month “n” (metric tons).

(C_{Electrode})_n = Average carbon content of the carbon electrode, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Carbon)_n = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month “n” (metric tons).

(C_{Carbon})_n = Average carbon content of the carbonaceous materials, from the carbon

analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Steel)_n = Mass of molten steel produced by the furnace in month “n” (metric tons).

(C_{Steel})_n = Average carbon content of the steel, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Slag)_n = Mass of slag produced by the furnace in month “n” (metric tons).

(C_{Slag})_n = Average carbon content of the slag, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(vi) For argon-oxygen decarburization vessels, estimate CO₂ emissions using Equation Q-6 of this section.

$$CO_2 = \sum_1^{12} \frac{44}{12} * (Steel)_n * [(C_{Steelin})_n - (C_{Steelout})_n] \quad (\text{Eq. Q-6})$$

Where:

CO₂ = Annual CO₂ mass emissions from the argon-oxygen decarburization vessel (metric tons).

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

(Steel)_n = Mass of molten steel charged to the vessel in month “n” (metric tons).

(C_{Steelin})_n = Carbon content of the molten steel before decarburization, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(C_{Steelout})_n = Average carbon content of the molten steel after decarburization, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

$$CO_2 = \sum_1^{12} \frac{44}{12} * [(F_g)_n * (C_{gf})_n * \frac{MW}{MVC} * 0.001 + (Ore)_n * (C_{ore}) + (Carbon)_n * (C_{Carbon})_n + (Other)_n * (C_{Other})_n - (Iron)_n * (C_{Iron})_n - (NM)_n * (C_{NM})_n] \quad (\text{Eq. Q-7})$$

(vii) For direct reduction furnaces, estimate CO₂ emissions using Equation Q-7 of this section.

Where:

CO₂ = Annual CO₂ mass emissions from the direct reduction furnace (metric tons).

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

(F_g)_n = Volume of the gaseous fuel combusted on day “n” or in month “n”, as applicable (scf).

(C_{gf})_n = Average carbon content of the gaseous fuel, from the fuel analysis results for month “n” (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)_n = Mass of iron ore or iron ore pellets fed to the furnace in month “n” (metric tons).

(C_{Ore})_n = Carbon content of the iron ore, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Carbon)_n = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month “n” (metric tons).

(C_{Carbon})_n = Average carbon content of the carbonaceous materials, from the carbon analysis results for month “n” (percent

by weight, expressed as a decimal fraction).

(Other)_n = Mass of other materials charged to the furnace in month “n” (metric tons).

(C_{Other})_n = Average carbon content of the other materials charged to the furnace, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(Iron)_n = Mass of iron produced in month “n” (metric tons).

(C_{Iron})_n = Carbon content of the iron, from the carbon analysis results for month “n” (percent by weight, expressed as a decimal fraction).

(NM)_n = Mass of non-metallic materials produced by the furnace in month “n” (metric tons).

$(C_{NM})_n$ = Average carbon content of the non-metallic materials, from the carbon analysis results for month "n" (percent by weight, expressed as a decimal fraction).

(3) *Site-specific emission factor method.* You must 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 (a)(3)(i) through (iv) of this section.

(i) You must measure the production rate or feed rate, as applicable, during

the test 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 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 (metric tons/hr).

5.18×10^{-7} = Conversion factor (tons/scf-% CO₂).

C_{CO₂} = Hourly CO₂ concentration (% 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.

(b) 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.

§ 98.174 Monitoring and QA/QC requirements.

(a) If you operate and maintain a CEMS that measures total CO₂ emissions consistent with subpart C of this part, you must meet the monitoring and QA/QC requirements of § 98.34(e).

(b) If you determine CO₂ emissions using the carbon balance procedure in § 98.173(a)(2), you must:

(1) For each process input and output other than fuels, determine the mass rate of each process input and output and record the totals for each process input and output for each calendar month. Determine the mass rate of fuels using the procedures for combustion units in § 98.34.

(2) For each process input and output other than fuels, sample each process input and output weekly and prepare a monthly composite sample for carbon analysis. For each process input that is a fuel, determine the carbon content using the procedures for combustion units in § 98.34.

(3) For each process input and output other than fuels, the carbon content must be analyzed by an independent certified laboratory using test method ASTM C25-06 ("Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime").

(3) For each process input and output other than fuels, the carbon content must be analyzed by an independent certified laboratory using the test methods specified in this paragraph.

(A) Use ASTM C25-06 ("Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime") for:

(i) Limestone, dolomite, and slag; ASTM D5373-08 ("Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke") for coal, coke, and other carbonaceous materials; ASTM E1915-07a ("Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry") for iron ore, taconite pellets, and other iron-bearing materials.

(ii) ASTM E1019-03 ("Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys") for iron and ferrous scrap.

(iii) ASTM E1019-03 ("Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys"), ASTM CS-104 ("Carbon Steel of Medium Carbon Content"), ISO/TR 15349-1:1998 ("Unalloyed steel—Determination of low carbon content. Part 1"), or ISO/TR 15349-3: 1998 ("Unalloyed steel—Determination of low carbon content. Part 3") as applicable for steel.

(c) If you determine CO₂ emissions using the site-specific emission factor procedure in § 98.173(a)(3), you must:

(1) Conduct an annual performance test under normal process operating conditions and at a production rate no less than 90 percent of the process rated capacity.

(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 nine 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 9 hours.

(4) Conduct the stack test using EPA Method 3A in 40 CFR part 60, Appendix A-2 to measure the CO₂ concentration, Method 2, 2A, 2C, 2D, or 2F in appendix A-1 or Method 26, appendix A-2 of 40 CFR part 60 to determine the stack gas volumetric flow rate, and Method 4 in appendix A-3 of 40 CFR part 60 to determine the moisture content of the stack gas.

(5) Conduct a new performance test and calculate a new site-specific emission factor if your fuel type or fuel/feedstock mix changes, the process changes in a manner that affects energy efficiency by more than 10 percent, or the process feed materials change in a manner that changes the carbon content of the fuel or feed by more than 10 percent.

(6) 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 CH₄, and N₂O emissions, you must meet the monitoring and QA/QC requirements of § 98.34.

(e) 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.

There are no allowances for missing data for facilities that estimate emissions using the carbon balance procedure in § 98.173(a)(2) or the site-emission factor procedure in § 98.133(a)(3); 100 percent data availability is required.

§ 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 (g) of this section for coke pushing and for each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace, as applicable:

(a) Annual CO₂ emissions by calendar quarters.

(b) Annual total for all process inputs and outputs when the carbon balance is used for specific processes by calendar quarters (short tons).

(c) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel by calendar quarters.

(d) Production capacity (in tons per year) for the production of taconite pellets, coke, sinter, iron, and raw steel.

(e) Annual operating hours for taconite furnaces, coke oven batteries, sinter production, blast furnaces, direct reduced iron furnaces, and electric arc furnaces.

(f) Site-specific emission factor for all process units for which the site-specific emission factor approach is used.

(g) Facilities that use CEMS must also comply with the data reporting requirements specified in § 98.36(d)(iv).

§ 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 (f) of this section, as applicable.

(a) Annual CO₂ emissions as measured or determined for each calendar quarter.

(b) Monthly total for all process inputs and outputs for each calendar quarter when the carbon balance is used for specific processes.

(c) Monthly analyses of carbon content for each calendar quarter when the carbon balance is used for specific processes.

(d) Site-specific emission factor for all process units for which the site-specific emission factor approach is used.

(e) Annual production quantity for taconite pellets, coke, sinter, iron, and raw steel with records for each calendar quarter.

(f) 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). The owner or operator also must document the procedures used to ensure the accuracy of the measurements of fuel usage

$$E_{\text{CO}_2} = \sum_{n=1}^{12} \frac{44}{12} * \left[(\text{Lead})_n * (C_{\text{Lead}})_n + (\text{Scrap}) \right]$$

Where:

CO₂ = Total annual CO₂ process emissions from the individual smelting furnace (metric tons).

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

(Lead)_n = Mass of lead ore charged to the smelting furnace in month "n" (metric tons).

$(C_{\text{Carbon}})_n$ = Average carbon content of the carbonaceous materials, from the carbon analysis results for month "n" (percent by weight, expressed as a decimal fraction).

$(\text{Other})_n$ = Mass of any other materials charged to the furnace in month "n" (metric tons).

$(C_{\text{Other}})_n$ = Average carbon content of any other materials from the carbon analysis results for month "n" (percent by weight, expressed as a decimal fraction).

(2) You must determine the total CO₂ emissions from the smelting furnaces using Equation R-2 of this section.

$$\text{CO}_2 = \sum_1^k E_{\text{CO}_2k} \quad (\text{Eq. R-2})$$

Where:

CO₂ = Total annual CO₂ emissions, metric tons/year.

E_{CO_2k} = Annual CO₂ emissions from smelting furnace k calculated using Equation R-1 of this subpart, metric tons/year.

k = Total number of smelting furnaces at facility used for the lead production.

§ 98.184 Monitoring and QA/QC requirements.

If you determine CO₂ emissions using the carbon input procedure in § 98.183(b), you must meet the requirements specified in paragraphs (a) through (c) of this section.

(a) Determine the mass of each solid carbon-containing input material by direct measurement of the quantity of the material placed in the unit or by calculations using process operating information, and record the total mass for the material for each calendar month.

(b) For each input material identified in paragraph (a) of this section, you must determine the average carbon content of the material for each calendar month using information provided by your material supplier or by collecting and analyzing a representative sample of the material.

(c) For each input material identified in paragraph (a) of this section for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed by an independent certified laboratory each calendar month using the test methods and their QA/QC procedures in § 98.7. Use ASTM E1941-04 ("Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys") for analysis of lead bearing ore, lead scrap, and lead ingot; ASTM D5373-02 ("Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke") for analysis of carbonaceous reducing agents, and

ASTM C25-06 ("Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime") for analysis of flux materials such as limestone or dolomite.

§ 98.185 Procedures for estimating missing data.

For the carbon input procedure in § 98.183(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.

(a) For each missing value of the carbon 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, 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 records of the mass of carbon-containing input material consumption, the substitute data value shall be the best available estimate of the mass of the input material. The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.186 Data Reporting Procedures.

In addition to the information required by § 98.3(c) of this part, each annual report must contain the information specified in paragraphs (a) through (e) of this section.

(a) Total annual CO₂ emissions from each smelting furnace operated at your facility for lead production (metric tons and the method used to estimate emissions).

(b) Facility lead product production capacity (metric tons).

(c) Annual facility production quantity (metric tons).

(d) Number of facility operating hours in calendar year.

(e) If you use the carbon input procedure, report for each carbon-containing input material consumed or used (other than fuel), the following information:

(1) Annual material quantity (in metric tons).

(2) Annual weighted average carbon content determined for material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).

§ 98.187 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 facility production quantity for each lead product (in metric tons).

(b) Number of facility operating hours each month.

(c) If you use the carbon input procedure, record for each carbon-containing input material consumed or used (other than fuel), the information specified in paragraphs (c)(1) and (2) of this section.

(1) Monthly material quantity (in metric tons).

(2) Monthly average carbon content determined for material and records of the supplier provided information or analyses used for the determination.

(d) 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. 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.

§ 98.188 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.

Lime manufacturing processes use a rotary lime kiln to produce a lime product (e.g., calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other products) from limestone or dolomite by means of calcination. The lime manufacturing source category consists of marketed lime manufacturing facilities and non-marketed lime manufacturing facilities.

§ 98.191 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a lime manufacturing process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.192 GHGs to report.

(a) You must report CO₂ process emissions from each lime kiln as specified in this subpart.

(b) You must report CO₂, N₂O, and CH₄ emissions from fuel combustion at each lime kiln and any other stationary combustion unit. You must follow the requirements of subpart C of this part.

§ 98.193 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements in subpart C of this part,

you must estimate total CO₂ emissions according to the requirements in § 98.33.

(b) If you do not operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements in subpart C of this part, you shall calculate CO₂ process emissions based on the production of each type of lime and calcined by-

products/wastes produced at each kiln according to the procedures in paragraphs (b)(1) through (4) of this section.

(1) You must calculate a monthly emission factor for each kiln 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 kiln:

$$EF_{k,i} = (SR_{CaO,i} \times CaO_i) + (SR_{MgO,i} \times MgO_i) \quad (\text{Eq. S-1})$$

Where:

EF_k = Emission factor for kiln k for lime type i, metric tons CO₂/metric ton lime.

SR_{CaO} = Stoichiometric ratio of CO₂ and CaO for lime type i (see Table S-1 of this subpart), metric tons CO₂/ metric tons CaO.

SR_{MgO} = Stoichiometric ratio of CO₂ and MgO for lime type i (See Table S-1 of this subpart), metric tons CO₂/ metric tons MgO.

CaO_i = Calcium oxide content for lime type i determined according to § 98.194(b), metric tons CaO/ton lime.

MgO_i = Magnesium oxide content for lime type i determined according to

§ 98.194(b), metric tons MgO/ metric ton lime.

(2) You must calculate the correction factor for by-product/waste products at the kiln (monthly) using Equation S-2 of this section:

$$CF_{lkd,k} = 1 + (M_{d,i} / M_{lime,i}) \times C_{d,i} \times F_{d,i} \quad (\text{Eq. S-2})$$

Where:

CF_{lkd,k} = Correction factor for by-products/waste products (such as lime kiln dust, LKD) at kiln k.

M_{d,i} = Weight of by-product/waste product not recycled to the kiln from lime type i, (tons of lime).

M_{lime,i} = Weight of lime produced at the kiln from lime type i, (tons of lime).

C_{d,i} = Fraction of original carbonate in the LKD for lime type i, (fraction).

F_{d,i} = Fraction of calcination of the original carbonate in the LKD of lime type i, assumed to be 1.00 (fraction).

(3) You must calculate annual CO₂ process emissions for each kiln using Equation S-3 of this section:

$$E_k \sum_{i=1}^{\phi} = \sum_n^{12} (E_{k,n} M_{k,n} CF_{lkd,k,n}) 0.97 \frac{2000}{2205} \quad (\text{Eq. S-3})$$

Where:

E_k = Annual CO₂ process emissions from lime production at kiln k (metric tons/year).

EF_{k,n} = Emission factor for lime in calendar month n (tons CO₂/tons carbonate) from Equation S-1.

M_{k,n} = Weight or mass of lime produced in calendar month n (tons/calendar month) from Equation S-3.

CF_{lkd,k,n} = Correction factor for LKD for lime in calendar month n from Equation S-2.

0.97 = Default correction factor for the proportion of hydrated lime (Assuming 90 percent of hydrated lime produced is high-calcium lime with a water content of 28 percent).

2000/2205

= Conversion factor for tons to metric tons.

= Number of lime types produced at kiln k.

(4) You must determine the total CO₂ process emissions for the facility using Equation S-4 of this section:

$$CO_2 = \sum_{k=1}^z E_k \quad (\text{Eq. S-4})$$

Where:

CO₂ = Annual CO₂ process emissions from lime production (metric tons/year).

E_k = Annual CO₂ emissions from lime production at kiln k (metric tons/year).

z = Number of kilns for lime production.

§ 98.194 Monitoring and QA/QC requirements.

(a) Determine the quantity of each type of lime produced at each kiln and the quantity of each type of calcined by-product/waste produced for each lime type, such as LKD, at the kiln on a monthly basis. The quantity of each type of calcined by-product/waste produced at the kiln must include material that is sold or used in a product, inventoried, or disposed of. The quantity of lime types and LKD 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.

(b) You must determine the chemical composition (percent total CaO and percent total MgO) of each type of lime and each type of calcined by-product/waste produced from each lime type by an off-site laboratory analysis on a monthly basis. This determination must be performed according to the requirements of ASTM C25-06, "Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime" (incorporated by reference—see § 98.7) and the procedures in "CO₂ Emissions Calculation Protocol for the Lime Industry English Units Version", February 5, 2008 Revision (incorporated by reference—see § 98.7).

(c) You must use the most recent analysis of calcium oxide and magnesium oxide content of each lime product in monthly calculations.

(d) You must follow the quality assurance/quality control procedures (including documentation) in the National Lime Association's "CO₂ Emissions Calculation Protocol for the Lime Industry-English Units Version", February 5, 2008 Revision (incorporated by reference—see § 98.7).

§ 98.195 Procedures for estimating missing data.

For the procedure in § 98.193(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.

(a) For each missing value of quantity of lime types, CaO and MgO content, and quantity of LKD 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.

(b) For missing records of mass of raw material consumption, the substitute data value shall be the best available estimate of the mass of inputs. The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.196 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a)(1) through (5) of this section for each lime kiln:

- (1) Annual CO₂ process emissions;
- (2) Annual lime production (in metric tons);

- (3) Annual lime production capacity (in metric tons) per facility;
- (4) All monthly emission factors, and;
- (5) Number of operating hours in calendar year.

(b) Facilities that use CEMS must also comply with the data reporting requirements specified in § 98.36.

§ 98.197 Records that must be retained.

(a) In addition to the records required by § 98.3(g), you must retain the following records specified in paragraphs (a)(1) through (4) of this section for each lime kiln:

- (1) Annual calcined by-products/waste products (by lime type summed from monthly data).
- (2) Lime production (by lime type) per month (metric tons).
- (3) Calculation of emission factors.
- (4) Results of chemical composition analysis (by lime product) per month.
- (5) Monthly correction factors for by-products/waste products for each kiln.

(b) Facilities that use CEMS must also comply with the recordkeeping requirements specified in § 98.37.

§ 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 _{C₂O}	0.7848
SR _{M_gO}	1.0918

Subpart T—Magnesium Production

§ 98.200 Definition of source category.

The magnesium production and processing source category consists of the following facilities:

(a) Any site where magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations.

(b) Any site where molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

§ 98.201 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a magnesium production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.202 GHGs to report.

(a) You must report emissions of the following gases in kilograms and metric tons CO₂e per year resulting from their use as cover gases or carrier gases in magnesium production or processing:

- (1) Sulfur hexafluoride (SF₆).
- (2) HFC-134a.
- (3) The fluorinated ketone, FK 5-1-12.
- (4) Any other fluorinated GHGs.
- (5) Carbon dioxide (CO₂).

(b) You must report CO₂, N₂O, and CH₄ emissions from each combustion unit on site by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

§ 98.203 Calculating GHG emissions.

(a) Calculate CO₂e GHG emissions from magnesium production or processing using Equation T-1 of this section. For Equation T-1 of this section, use the procedures of either paragraph (b) or (c) of this section to estimate consumption of cover gas or carrier gas.

$$E_{GHG} = E_{SF6} + E_{134a} + E_{FK} + E_{CO2} + E_{OG} \quad (\text{Eq. T-1})$$

$$E_{SF6} = C_{SF6} \times 23.9$$

$$E_{134a} = C_{134a} \times 1.3$$

$$E_{FK} = C_{FK} \times 0.001$$

$$E_{CO2} = C_{CO2} \times 0.001$$

$$E_{OG} = C_{OG} \times GWP_{OG} / 1000$$

Where:

E_{GHG} = GHG emissions from magnesium production and processing (mtCO₂e).

E_{SF6} = SF₆ emissions from magnesium production and processing (mtCO₂e).

E_{134a} = HFC-134a emissions from magnesium production and processing (mtCO₂e).

E_{FK} = FK 5–1–12 emissions from magnesium production and processing (mtCO₂e).
 E_{CO_2} = CO₂ emissions from magnesium production and processing (mtCO₂e).
 E_{OG} = Emissions of other fluorinated GHGs from magnesium production and processing (mtCO₂e).
 C_{SF_6} = Consumption of SF₆ (kg).
 C_{134a} = Consumption of HFC–134a (kg).
 C_{FK} = Consumption of FK 5–1–12 (kg).
 C_{CO_2} = Consumption of CO₂ (kg).
 C_{OG} = Consumption of other fluorinated GHGs (kg).
 GWP_{OG} = The Global Warming Potential of the other fluorinated GHG provided in Table A–1 in subpart A of this part.

(b) To estimate consumption of cover gases or carrier gases by monitoring changes in container masses and inventories, consumption of each cover gas or carrier gas shall be estimated using Equation T–2 of this section:

$$C = I_B - I_E + A - D \quad (\text{Eq. T-2})$$

Where:

C = Consumption of any cover gas or carrier gas in kg over the period (e.g., 1 year).
 I_B = Inventory of any cover gas or carrier gas stored in cylinders or other containers at the beginning of the period (e.g., 1 year), including heels, in kg.
 I_E = Inventory of any cover gas or carrier gas stored in cylinders or other containers at the end of the period (e.g., 1 year), including heels, in kg.
 A = Acquisitions of any cover gas or carrier gas during the period (e.g., 1 year) through purchases or other transactions, including heels in cylinders or other containers returned to the magnesium production or processing facility, in kg.
 D = Disbursements of cover gas or carrier gas to sources and locations outside the facility through sales or other transactions during the period, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas distributor, in kg.

(c) To estimate consumption of cover gases or carrier gases by monitoring changes in the masses of individual containers as their contents are used, consumption of each cover gas or carrier gas shall be estimated using Equation T–3 of this section:

$$C_{GHG} = \sum_{p=1}^n Q_p \quad (\text{Eq. T-3})$$

Where:

C_{GHG} = The consumption of the cover gas over the period (kg).
 Q_p = The mass of the cover gas used over the period (kg).
 n = The number of periods in the year.

(d) For purposes of Equation T–3 of this section, the mass of the cover gas used over the period p shall be estimated by using Equation T–4 of this section:

$$Q_p = M_B - M_E \quad (\text{Eq. T-4})$$

Where:

Q_p = The mass of the cover gas used over the period (kg).
 M_B = The mass of the contents of the cylinder at the beginning of period p .
 M_E = The mass of the contents of the cylinder at the end of period p .

§ 98.204 Monitoring and QA/QC requirements.

(a) Consumption of cover gases and carrier gases may be estimated by monitoring the changes in container weights and inventories using Equation T–2 of this subpart, by monitoring the changes in individual container weights as the contents of each container are used using Equations T–3 and T–4 of this subpart, or by monitoring the mass flow of the pure cover gas or carrier gas into the cover gas distribution system. Consumption must be estimated at least annually.

(b) When estimating consumption by monitoring the mass flow of the pure cover gas or carrier gas into the cover gas distribution system, you must use gas flow meters with an accuracy of one percent of full scale or better.

(c) When estimating consumption using Equation T–2 of this subpart, you must ensure that all the quantities required by Equation T–2 of this subpart have been measured using scales or load cells with an accuracy of one percent of full scale or better, accounting for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier (e.g., for the contents of containers containing new gas or for the heels remaining in containers returned to the gas supplier); however, you remain responsible for the accuracy of these masses and weights under this subpart.

(d) When estimating consumption using Equations T–3 and T–4 of this subpart, you must monitor and record container identities and masses as follows:

(1) Track the identities and masses of containers leaving and entering storage with check-out and check-in sheets and procedures. The masses of cylinders returning to storage shall be measured immediately before the cylinders are put back into storage.

(2) Ensure that all the quantities required by Equations T–3 and T–4 of this subpart have been measured using scales or load cells with an accuracy of one percent of full scale or better, accounting for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier (e.g., for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the

gas supplier); however, you remain responsible for the accuracy of these masses or weights under this subpart.

(e) All flowmeters, scales, and load cells used to measure quantities that are to be reported under this subpart shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others). Alternatively, calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

§ 98.205 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emission calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter will be used in the calculations as specified in paragraph (b) of this section.

(b) Replace missing data on the consumption of cover gases by multiplying magnesium production during the missing data period by the average cover gas usage rate from the most recent period when operating conditions were similar to those for the period for which the data are missing. Calculate the usage rate for each cover gas using Equation T–5 of this section:

$$R_{GHG} = C_{GHG} / Mg \quad (\text{Eq. T-5})$$

Where:

R_{GHG} = The usage rate for a particular cover gas over the period.
 C_{GHG} = The consumption of that cover gas over the period (kg).
 Mg = The magnesium produced or fed into the casting process over the period (metric tons).

§ 98.206 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must include the following information for the magnesium production and processing facility:

(a) Total GHG emissions for your facility by gas in metric tons and CO₂e.

(b) Type of production process (e.g. primary, secondary, die casting).

(c) Magnesium production amount in metric tons for each process type.

(d) Cover gas flow rate and composition.

(e) Amount of CO₂ used as a carrier gas during the reporting period.

(f) For any missing data, you must report the length of time the data were missing, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

(g) The facility's cover gas usage rate.

(h) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (e.g., installation of new melt protection technology or leak discovered in the cover gas delivery system that resulted in increased consumption).

(i) A description of any new melt protection technologies adopted to account for reduced GHG emissions in any given year.

§ 98.207 Records that must be retained.

In addition to the records specified in § 98.3(g), you must retain the following information for the magnesium production or processing facility:

(a) Check-out and weigh-in sheets and procedures for cylinders.

(b) Accuracy certifications and calibration records for scales.

(c) Residual gas amounts in cylinders sent back to suppliers.

(d) Invoices for gas purchases and sales.

§ 98.208 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart U—Miscellaneous Uses of Carbonate

§ 98.210 Definition of the source category.

(a) This source category consists of any equipment that uses limestone, dolomite, ankerite, magnesite, silerite, rhodochrosite, sodium carbonate, or any

other carbonate in a manufacturing process.

(b) This source category does not include carbonates consumed for producing cement, glass, ferroalloys, iron and steel, lead, lime, pulp and paper, or zinc.

§ 98.211 Reporting threshold.

You must report GHG emissions from miscellaneous uses of carbonate if your facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.212 GHGs to report.

You must report CO₂ emissions aggregated for all miscellaneous carbonate use at the facility.

§ 98.213 Calculating GHG emissions.

Calculate process emissions of CO₂ using Equation U-1 of this section.

$$E_{CO_2} = \sum_i M_i \star EF_i \star F_i \star \frac{2000}{2205} \quad (\text{Eq. U-1})$$

Where:

ECO₂ = 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.

i = number of the carbonate types.

2000/2205 = Conversion factor to convert tons to metric tons.

As an alternative to measuring the calcination fraction (F_i), a value of 1.0 can be used in Equation U-1 of this section.

§ 98.214 Monitoring and QA/QC requirements.

(a) The total mass of carbonate consumed can be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders, or purchase records.

(b) Determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis conducted by a certified laboratory using a suitable method such as using an x-ray fluorescence test or other enhanced testing method published by a consensus standards organization (e.g., ASTM, ASME, API, etc.).

§ 98.215 Procedures for estimating missing data.

There are no missing data procedures for miscellaneous uses of carbonates. A complete record of all measured parameters used in the GHG emissions calculations is required. A re-test must be performed if the data from any measurements are determined to be invalid.

§ 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 (d) of this section at the facility level.

(a) Annual CO₂ emissions from miscellaneous carbonate use (in metric tons).

(b) Annual carbonate consumption (by carbonate type in tons).

(c) Annual fraction calcinations.

(d) Average annual mass fraction of carbonate-based mineral in carbonate-based raw material by carbonate type.

§ 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 (c) of this section.

(a) Records of monthly carbonate consumption (by carbonate type). You must also document the procedures used to ensure the accuracy of monthly carbonate consumption.

(b) Annual chemical analysis of mass fraction of carbonate-based mineral in

carbonate-based raw material by carbonate type.

(c) Records of all carbonate purchases and deliveries.

§ 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	CO ₂ emission factor (tons CO ₂ /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	0.44197
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 oxidation, condensation, and absorption to produce a weak nitric acid (30 to 70 percent in strength).

§ 98.221 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a nitric acid production

process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.222 GHGs to report.

(a) You must report N₂O process emissions from each nitric acid production line as required by this subpart.

(b) You must report CO₂, CH₄, and N₂O emissions from each stationary combustion unit. You must follow the requirements of subpart C of this part.

§ 98.223 Calculating GHG emissions.

You must determine annual N₂O process emissions from each nitric acid production line using a site-specific emission factor according to paragraphs (a) through (e) of this section.

(a) You must conduct an annual performance test to measure N₂O emissions from the absorber tail gas vent for each nitric acid production line. You must conduct the performance test(s) under normal process operating conditions.

(b) You must conduct the emissions test(s) using either EPA Method 320 in

40 CFR part 63, appendix A or ASTM D6348–03 incorporated by reference in § 98.7 to measure the N₂O concentration 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.

(c) You must measure the production rate during the test(s) and calculate the production rate for the test period in tons (100 percent acid basis) per hour.

(d) You must calculate a site-specific emission factor for each nitric acid production line according to Equation V–1 of this section:

$$EF_{N_2O} = \frac{\sum_{i=1}^n \frac{C_{N_2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \quad (\text{Eq. V-1})$$

Where:

EF_{N₂O} = Site-specific N₂O emissions factor (lb N₂O/ton nitric acid produced, 100 percent acid basis).

C_{N₂O} = N₂O concentration during performance test (ppm N₂O).

1.14×10⁻⁷ = Conversion factor (lb/dscf-ppm N₂O).

Q = Volumetric flow rate of effluent gas (dscf/hr).

P = Production rate during performance test (tons nitric acid produced per hour (100 percent acid basis)).

n = Number of test runs.

(e) You must calculate N₂O emissions for each nitric acid production line by multiplying the emissions factor by the total annual production from that production line, according to Equation V–2 of this section:

$$E_{N_2O} = \frac{EF_{N_2O} * P_a * (1 - DF_N) * AF_N}{2205} \quad (\text{Eq. V-2})$$

Where:

E_{N₂O} = N₂O mass emissions per year (metric tons of N₂O).

EF_{N₂O} = Site-specific N₂O emission factor for the production line (lb N₂O/ton acid produced, 100 percent acid basis).

P_a = Total production for the year from the production line (ton acid produced, 100 percent acid basis).

DF_N = Destruction factor of N₂O abatement technology, 'as specified by the abatement device manufacturer (percent of N₂O removed from air stream).

AF_N = Abatement factor of N₂O abatement technology (percent of year that abatement technology was used).

2205 = Conversion factor (lb/metric ton).

process modifications have occurred or operating conditions have changed. Only the data consistent with the period after the changes were implemented shall be used.

(b) Each facility must conduct the performance test(s) according to a test plan and EPA Method 320 in 40 CFR part 63, Appendix A or ASTM D6348–03 (incorporated by reference—see § 98.7). All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. The report must include the items in paragraphs (b)(1) through (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. The production rate can be determined through sales records or by direct measurement using flow meters or weigh scales.

emissions from nitric acid production lines. A complete record of all measured parameters used in the GHG emissions calculations is required.

§ 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 (h) of this section for each nitric acid production line:

(a) Annual nitric acid production capacity (metric tons).

(b) Annual nitric acid production (metric tons).

(c) Number of operating hours in the calendar year (hours).

(d) Emission factor(s) used (lb N₂O/ton of nitric acid produced).

(e) Type of nitric acid process used.

(f) Abatement technology used (if applicable).

(g) Abatement utilization factor (percent of time that abatement system is operating).

(h) Abatement technology efficiency.

§ 98.224 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new site-specific emissions factor at least annually. You must also conduct a new performance test whenever the production rate of a production line is changed by more than 10 percent from the production rate measured during the most recent performance test. The new emissions factor may be calculated using all available performance test data (i.e., averaged with the data from previous years), except in cases where

§ 98.225 Procedures for estimating missing data.

Procedures for estimating missing data are not provided for N₂O process

§ 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 (c) of this section for each nitric acid production line:

(a) Records of significant changes to process.

(b) Annual test reports of N₂O emissions.

(c) Calculations of the site-specific emissions factor(s).

§ 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—Oil and Natural Gas Systems

§ 98.230 Definition of the source category.

This source category consists of the following facilities:

(a) Offshore petroleum and natural gas production facilities.

(b) Onshore natural gas processing facilities.

(c) Onshore natural gas transmission compression facilities.

(d) Underground natural gas storage facilities.

(e) Liquefied natural gas storage facilities.

(f) Liquefied natural gas import and export facilities.

§ 98.231 Reporting threshold.

You must report GHG emissions from oil and natural gas systems if your facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.232 GHGs to report.

(a) You must report CO₂ and CH₄ emissions in metric tons per year from sources specified in § 98.232(a)(1) through (23) at offshore petroleum and natural gas production facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities and liquefied natural gas import and export facilities.

(1) Acid gas removal (AGR) vent stacks.

(2) Blowdown vent stacks.

(3) Centrifugal compressor dry seals.

(4) Centrifugal compressor wet seals.

(5) Compressor fugitive emissions.

(6) Compressor wet seal degassing vents.

(7) Dehydrator vent stacks.

(8) Flare stacks.

(9) Liquefied natural gas import and export facilities fugitive emissions.

(10) Liquefied natural gas storage facilities fugitive emissions.

(11) Natural gas driven pneumatic pumps.

(12) Natural gas driven pneumatic manual valve actuator devices.

(13) Natural gas driven pneumatic valve bleed devices.

(14) Non-pneumatic pumps.

(15) Offshore platform pipeline fugitive emissions.

(16) Open-ended lines (oels).

(17) Pump seals.

(18) Platform fugitive emissions.

(19) Processing facility fugitive emissions.

(20) Reciprocating compressor rod packing.

(21) Storage station fugitive emissions.

(22) Storage tanks.

(23) Storage wellhead fugitive emissions.

(24) Transmission station fugitive emissions.

(b) You must report the CO₂, CH₄, and N₂O emissions for stationary combustion sources, by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

§ 98.233 Calculating GHG emissions.

(a) Estimate emissions using either an annual direct measurement, as specified in § 98.234, or an engineering estimation method specified in this section. You may use the engineering estimation method only for sources for which a method is specified in this section.

(b) You may use engineering estimation methods described in this section to calculate emissions from the following fugitive emissions sources:

(1) Acid gas removal vent stacks.

(2) Natural gas driven pneumatic pumps.

(3) Natural gas driven pneumatic manual valve actuator devices.

(4) Natural gas driven pneumatic valve bleed devices.

(5) Blowdown vent stacks.

(6) Dehydrator vent stacks.

(c) A combination of engineering estimation described in this section and direct measurement described in § 98.234 shall be used to calculate emissions from the following fugitive emissions sources:

(1) Flare stacks.

(2) Storage tanks.

(3) Compressor wet seal degassing vents.

(d) You must use the methods described in § 98.234 (d) or (e) to conduct annual leak detection of fugitive emissions from all sources listed in § 98.232(a). If fugitive emissions are detected, engineering estimation methods may be used for sources listed in paragraphs (b) and (c) of this section. If engineering estimation is used, emissions must be calculated

using the appropriate method from paragraphs (d)(1) through (9) of this section:

(1) Acid gas removal vent stack. Calculate acid gas removal vent stack fugitive emissions using simulation software packages, such as ASPEN™ or AMINECalc™. Any standard simulation software may be used provided it accounts for the following parameters:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate and weight.

(vii) If the acid gas removal unit is capturing CO₂ and transferring it off site, then refer to subpart OO of this part for calculating transferred CO₂.

(2) Natural gas driven pneumatic pump. Calculate fugitive emissions from a natural gas driven pneumatic pump as follows:

(i) Calculate fugitive emissions using manufacturer data.

(A) Obtain from the manufacturer specific pump model natural gas emission per unit volume of liquid pumped at operating pressures.

(B) Maintain a log of the amount of liquid pumped annually from individual pumps.

(C) Calculate the natural gas fugitive emissions for each pump using Equation W-1 of this section.

$$E_{s,n} = F_s * V \quad (\text{Eq. W-1})$$

Where:

E_{s,n} = Natural gas fugitive emissions at standard conditions.

F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at discharge pressure" units at standard conditions, as provided by the manufacturer.

V = Volume of liquid pumped annually.

(D) Both CH₄ and CO₂ volumetric and mass fugitive emissions shall be calculated from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) If manufacturer data for F_s are not available, follow the method in § 98.234 (i)(1).

(3) Natural gas driven pneumatic manual valve actuator devices.

Calculate fugitive emissions from a natural gas driven pneumatic manual valve actuator device as follows:

(i) Calculate fugitive emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas emission per actuation.

(B) Maintain a log of the number of times the pneumatic device was actuated throughout the reporting period.

(C) Calculate the natural gas fugitive emissions for each manual valve actuator using Equation W-2 of this section.

$$E_{s,n} = A_s * N \quad (\text{Eq. W-2})$$

Where:

$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.

A_s = Natural gas driven pneumatic valve actuator natural gas emission in "emission per actuation" units at standard conditions, as provided by the manufacturer.

N = Number of times the pneumatic device was actuated in a way that vented natural gas to the atmosphere through the reporting period.

(D) Calculate both CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) Follow the method in § 98.234(i)(2) if manufacturer data are not available.

(4) Natural gas driven pneumatic valve bleed devices. Calculate fugitive emissions from a natural gas driven pneumatic valve bleed device as follows:

(i) Calculate fugitive emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(B) Calculate the natural gas fugitive emissions for each valve bleed device using Equation W-3 of this section.

$$E_{s,n} = B_s * T \quad (\text{Eq. W-3})$$

Where:

$E_{s,n}$ = Natural gas fugitive emissions at standard conditions.

B_s = Natural gas driven pneumatic device bleed rate in "emission per unit time" units at standard conditions, as provided by the manufacturer.

T = Amount of time the pneumatic device has been operational through the reporting period.

(C) Calculate both CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) Follow the method in § 98.234(i)(3) if manufacturer data are not available.

(5) Blowdown vent stacks. Calculate fugitive emissions from blowdown vent stacks as follows:

(i) Calculate the total volume (including, but not limited to pipelines and vessels) between isolation valves (V_v in Equation W-4 of this subpart).

(ii) Retain logs of the number of blowdowns for each equipment type.

(iii) Calculate the total annual fugitive emissions using the following Equation W-4 of this section:

$$E_{a,n} = N * V_v \quad (\text{Eq. W-4})$$

Where:

$E_{a,n}$ = Natural gas fugitive emissions at ambient conditions from blowdowns.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves.

(iv) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(v) Calculate both CH₄ and CO₂ volumetric and mass fugitive emissions

from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(6) Dehydrator vent stacks. Calculate fugitive emissions from a dehydrator vent stack using a simulation software packages, such as GLYCalc™. Any standard simulation software may be used provided it accounts for the following parameters:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: Including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping natural gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature, pressure, and composition.

(7) Flare stacks. Calculate fugitive emissions from a flare stack as follows:

(i) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares.

(ii) Calculate volume of natural gas sent to flare from velocity measurement in § 98.234(j) using manufacturer's manual for the specific meter used to measure velocity.

(iii) Calculate GHG volumetric fugitive emissions at actual conditions using Equation W-5 of this section:

$$E_{a,i} = V_a \times (1 - \eta) \times X_i + (1 - K) * \eta * V_a * Y_j * R_{j,i} \quad (\text{Eq. W-5})$$

Where:

$E_{a,i}$ = Annual fugitive emissions from flare stack.

V_a = Volume of natural gas sent to flare stack determined from § 98.234(j)(1).

η = Percent of natural gas combusted by flare (default is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares).

X_i = Concentration of GHG i in the flare gas determined from § 98.234(j)(1).

Y_j = Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus).

$R_{j,i}$ = Number of carbon atoms in the natural gas hydrocarbon constituent j ; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

K = "1" when GHG i is CH₄ and "0" when GHG i is CO₂.

(iv) Calculate GHG volumetric fugitive emissions at standard conditions using Equation W-6 of this section.

$$E_{s,i} = \frac{E_{a,i} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \quad (\text{Eq. W-6})$$

Where:

$E_{s,i}$ = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.

$E_{a,i}$ = Natural gas volumetric fugitive emissions at actual conditions.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (inches of Hg).

P_a = Absolute pressure at ambient conditions (inches of Hg).

(v) Calculate both CH₄ and CO₂ mass fugitive emissions from volumetric CH₄ and CO₂ fugitive emissions using calculations in paragraph (g) of this section.

(8) Storage tanks. Calculate fugitive emissions from a storage tank as follows:

(i) Calculate the total annual hydrocarbon vapor fugitive emissions using Equation W-7 of this section:

$$E_{a,h} = Q \times ER \quad (\text{Eq. W-7})$$

Where:

$E_{a,h}$ = Hydrocarbon vapor fugitive emissions at actual conditions.

Q = Storage tank total annual throughput.

ER = Measured hydrocarbon vapor emissions rate per throughput (e.g. cubic feet/barrel) determined from § 98.234(j)(2).

(ii) Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon fugitive emissions using Equation W-8 of this section.

$$E_{s,i} = E_{s,h} * M_i \quad (\text{Eq. W-8})$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.

$E_{s,h}$ = Hydrocarbon vapor volumetric fugitive emissions at standard conditions.

M_i = Mole percent of a particular GHG i in the hydrocarbon vapors; hydrocarbon vapor analysis shall be conducted in accordance with ASTM D1945-03.

(iv) Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric fugitive emissions using calculations in paragraph (g) of this section.

(9) Compressor wet seal degassing vents. Calculate fugitive emissions from compressor wet seal degassing vents as follows:

(i) Calculate volume of natural gas sent to vent from velocity measurement in § 98.234(j) using manufacturer's manual for the specific meter used to measure velocity.

(ii) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(e) Calculate natural gas volumetric fugitive emissions at standard conditions by converting ambient temperature and pressure of natural gas fugitive emissions to standard temperature and pressure natural using Equation W-9 of this section.

$$E_{s,n} = \frac{E_{a,n} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \quad (\text{Eq. W-9})$$

Where:

$E_{s,n}$ = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.

$E_{a,n}$ = Natural gas volumetric fugitive emissions at actual conditions.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (inches of Hg).

P_a = Absolute pressure at ambient conditions (inches of Hg).

(f) Calculate GHG volumetric fugitive emissions at standard conditions as specified in paragraphs (f)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 fugitive emissions from natural gas fugitive emissions using Equation W-10 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad (\text{Eq. W-10})$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.

$E_{s,n}$ = Natural gas volumetric fugitive emissions at standard conditions.

M_i = Mole percent of GHG i in the natural gas.

(2) For Equation W-10 of this section, the mole percent, M_i , shall be the annual average mole percent for each facility, as specified in paragraphs (f)(2)(i) through (vi) of this section.

(i) GHG mole percent in produced natural gas for offshore petroleum and natural gas production facilities.

(ii) GHG mole percent in feed natural gas for all fugitive emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all fugitive emissions sources downstream of the de-methanizer for onshore natural gas processing facilities.

(iii) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(v) GHG mole percent in natural gas stored in LNG storage facilities.

(vi) GHG mole percent in natural gas stored in LNG import and export facilities.

(g) Calculate GHG mass fugitive emissions at standard conditions by converting the GHG volumetric fugitive emissions into mass fugitive emissions using Equation W-11 of this section.

$$\text{Mass}_{s,i} = E_{s,i} * \rho_i \quad (\text{Eq. W-11})$$

Where:

$\text{Mass}_{s,i}$ = GHG i (either CH_4 or CO_2) mass fugitive emissions at standard conditions.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.

ρ_i = Density of GHG i; 1.87 kg/m³ for CO_2 and 0.68 kg/m³ for CH_4 .

§ 98.234 Monitoring and QA/QC requirements.

(a) You must use the methods described in paragraphs (d) or (e) in this section to conduct annual leak detection of fugitive emissions from all sources listed in § 98.232(a), whether in operation or on standby. If fugitive emissions are detected for sources listed in paragraph (b) of this section, you must use the measurement methods described in paragraph (c) of this section to measure emissions from each source with fugitive emissions.

(b) You shall use detection instruments described in paragraphs (d) and (e) of this section to monitor the following fugitive emissions:

(1) Centrifugal compressor dry seals fugitive emissions.

(2) Centrifugal compressor wet seals fugitive emissions.

(3) Compressor fugitive emissions.

(4) LNG import and export facility fugitive emissions.

(5) LNG storage station fugitive emissions.

(6) Non-pneumatic pumps fugitive emissions.

(7) Open-ended lines (OELs) fugitive emissions.

(8) Pump seals fugitive emissions.

(9) Offshore platform pipeline fugitive emissions.

(10) Platform fugitive emissions.

(11) Processing facility fugitive emissions.

(12) Reciprocating compressor rod packing fugitive emissions.

(13) Storage station fugitive emissions.

(14) Transmission station fugitive emissions.

(15) Storage wellhead fugitive emissions.

(c) You shall use a high volume sampler, described in paragraph (f) of this section, to measure fugitive emissions from the sources detected in § 98.234(b), except as provided in paragraphs (c)(1) and (2) of this section:

(1) Where high volume samplers cannot capture all of the fugitive emissions, you shall use calibrated bags described in paragraph (g) of this section or meters described in paragraph (h) of this section to measure the following fugitive emissions:

(i) Open-ended lines (OELs).

(ii) Centrifugal compressor dry seals fugitive emissions.

(iii) Centrifugal compressor wet seals fugitive emissions.

(iv) Compressor fugitive emissions.

(v) Pump seals fugitive emissions.

(vi) Reciprocating compressor rod packing fugitive emissions.

(vii) Flare stacks and storage tanks, except that you shall use meters in

combination with engineering estimation methods to calculate fugitive emissions.

(2) Use hot wire anemometer to calculate fugitive emissions from centrifugal compressor wet seal degassing vents and flares where it is unsafe or too high a flow rate to use calibrated bags.

(d) Infrared Remote Fugitive Emissions Detection.

(1) Use infrared fugitive emissions detection instruments that can identify specific equipment sources as emitting. Such instruments must have the capability to trace a fugitive emission back to the specific point where it escapes the process and enters the atmosphere.

(2) If you are using instruments that visually display an image of fugitive emissions, you shall inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions at least once annually.

(3) If you are using any other infrared detection instruments, such as those based on infrared laser reflection, you shall monitor all potential emission points at least once annually.

(4) Perform fugitive emissions detection under favorable conditions, including but not limited to during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument.

(5) Use fugitive emissions detection and measurement instrument manuals to determine optimal operating conditions.

(e) Use organic vapor analyzers (OVAs) and toxic vapor analyzers (TVAs) for all fugitive emissions detection that are safely accessible at close-range.

(1) Check each potential emissions source, all joints, connections, and other potential paths to the atmosphere for emissions.

(2) Evaluate the lag time between the instrument sensing and alerting caused by the residence time of a sample in the probe shall be evaluated; upon alert, the instrument shall be slowly retraced over the source to pinpoint the location of fugitive emissions.

(3) Use Method 21 of 40 CFR part 60, appendix A-7, Determination of Volatile Organic Compound Leaks to calibrate OVAs and TVAs.

(f) Use a high volume sampler to measure only cold and steady emissions within the capacity of the instrument.

(1) A trained technician shall conduct measurements. The technician shall be

conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, including, but not limited to, positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(f) and (g).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH₄ by using calibrated gas samples and by following manufacturer's instructions for calibration.

(g) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and the entire fugitive emissions volume can be captured for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag.

(2) Perform three measurements of the time required to fill the bag; report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(e).

(4) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(f) and (g).

(5) Obtain consistent results when measuring the time it takes to fill the bag with fugitive emissions.

(h) Channel all emissions from a single source directly through the meter when using metering (e.g., rotameters, turbine meters, and others).

(1) Use an appropriately sized meter so that the flow does not exceed the full range of the meter in the course of measurement and conversely has sufficient momentum for the meter to register continuously in the course of measurement.

(2) Estimate natural gas volumetric fugitive emissions at standard conditions using calculations in § 98.233(f).

(3) Estimate CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive

emissions using calculations in § 98.233(f) and (g).

(4) Calibrate the meter using either one of the two methods provided as follows:

(i) Develop calibration curves by following the manufacturer's instruction.

(ii) Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST). Determine correction factors for the flow meter according to the manufacturer's instructions. Record deviations from the correct reading at several flow rates. Plot the data points, comparing the flowmeter output to the actual flowrate as determined by the master weigh scale and use the difference as a correction factor.

(i) Where engineering estimation as described in § 98.233 is not possible, use direct measurement methods as follows:

(1) If manufacturer data on pneumatic pump natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids. Determine the volume of liquid being pumped from the manufacturer's manual to provide the amount of natural gas emitted per unit of liquid pumped.

(i) Record natural gas conditions (temperature and pressure) and convert natural gas emission per unit volume of liquid pumped at actual conditions into natural gas emission per pumping cycle at standard conditions using Equation W-9 of § 98.233.

(ii) Calculate annual fugitive emissions from the pump using Equation W-1, by replacing the manufacturer's data on emission (variable F_s) in the Equation with the standard conditions natural gas emission calculated in § 98.234(i)(1)(i).

(iii) Estimate CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in § 98.233(f) and (g).

(2) If manufacturer data on pneumatic manual valve actuator device natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per actuation using a calibrated bag for each pneumatic device per actuation.

(i) Record natural gas conditions (temperature and pressure) and convert natural gas emission at actual conditions into natural gas emission per

§ 98.242 GHGs to report.

You must report the information in paragraphs (a) through (d) of this section:

(a) CO₂ emissions from each petrochemical process unit, following the methods and procedures in §§ 98.243 through 98.248. You must include the volume of any CO₂ captured from process off-gas in the reported CO₂ emissions.

(b) CO₂, CH₄, and N₂O emissions from stationary combustion units. For each stationary combustion unit, you must follow the calculation methods and other requirements specified in subpart C of this part. If you determine CO₂ process-based emissions in accordance with § 98.243(a)(2), then for each stationary combustion unit that burns off-gas from a petrochemical process, estimate CO₂, CH₄, and N₂O emissions for the combustion of supplemental fuel in accordance with subpart C of this part. In addition, estimate CH₄ and N₂O emissions from combusting off-gas according to the requirements in § 98.33(c)(2) and (3) using the emission factors for Refinery Gas in Table C-3 in subpart C of this part.

(c) CO₂ captured. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in subpart PP of this part.

(d) CH₄ emissions for each on-site wastewater treatment system. For wastewater treatment systems, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in subpart II of this part.

§ 98.243 Calculating GHG emissions.

(a) Determine process-based GHG emissions in accordance with the procedures specified in either paragraph (a)(1) or (2) of this section, and if applicable, comply with the procedures in paragraph (b) of this section.

(1) *Continuous emission monitoring system (CEMS).*

(i) If you operate and maintain a CEMS that measures total CO₂ emissions from process vents and combustion sources according to subpart C of this part, you must estimate total CO₂ emissions according to the Tier 4 Calculation Methodology requirements in § 98.33(a)(4). For each flare, estimate CO₂, CH₄, and N₂O emissions using the methodology specified in § 98.253(b)(1) and (2).

(ii) If you elect to install CEMS to comply with this subpart, you must route all process vent emissions to one or more stacks and use a CEMS on each stack (except flare stacks) to measure CO₂ emissions. You must estimate total CO₂ emissions according to the Tier 4 Calculation Methodology requirements in § 98.33(a)(4). For each flare, estimate CO₂, CH₄, and N₂O emissions using the methodology specified in § 98.253(b)(1) and (2) of subpart Y of this part.

(2) *Mass balance for each petrochemical process unit.* Estimate the emissions of CO₂ from each process unit, for each calendar week as described in paragraphs (a)(2)(i) through (v) of this section.

(i) Measure the volume of each gaseous and liquid feedstock and product continuously with a flow meter by following the procedures outlined in § 98.244(b)(2). Fuels used for combustion purposes are not considered to be feedstocks.

(ii) Measure the mass rate of each solid feedstock and product by following the procedures outlined in § 98.244(b)(1) and record the total for each calendar week.

(iii) Collect a sample of each feedstock and product at least once per week and determine the carbon content of each sample according to the procedures in § 98.244(b)(3).

(iv) If you determine that the weekly average concentration of a specific compound in a feedstock or product is always 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 (a)(2)(iii) 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 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 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 weekly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(v) Estimate CO₂ mass emissions for each petrochemical process unit using Equations X-1 through X-4 of this section:

$$C_g = \sum_{n=1}^{52} \sum_{i=1}^{j \text{ or } k} \left[(F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC} \right] \quad (\text{Eq. X-1})$$

Where:

C_g = Annual net contribution to estimated emissions from carbon (C) in gaseous feedstocks (kilograms/year, kg/yr).

(F_{gf})_{i,n} = Volume of gaseous feedstock i introduced in week "n" (standard cubic feet, scf).

(CC_{gf})_{i,n} = Average carbon content of the gaseous feedstock i for week "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 week "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 week "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.

$$C_l = \sum_{n=1}^{52} \sum_{i=1}^{j \text{ or } k} \left[(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n} \right] \quad (\text{Eq. X-2})$$

Where:

C_l = Annual net contribution to estimated emissions from carbon in liquid feedstocks (kg/yr).

$(F_{lf})_{i,n}$ = Volume of liquid feedstock i introduced in week "n" (gallons).
 $(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for week "n" (kg C per gallon of feedstock).

$(P_{lp})_{i,n}$ = Volume of liquid product i produced in week "n" (gallons).
 $(CC_{lp})_{i,n}$ = Average carbon content of liquid product i , including organic liquid wastes, for week "n" (kg C per gallon of product).

$$C_s = \sum_{n=1}^{52} \sum_{i=1}^{j \text{ or } k} \left[(F_{sf})_{i,n} * (CC_{sf})_{i,n} - (P_{sp})_{i,n} * (CC_{sp})_{i,n} \right] \quad (\text{Eq. X-3})$$

Where:

C_s = Annual net contribution to estimated emissions from carbon in solid feedstocks (kg/yr).

$(F_{sf})_{i,n}$ = Mass of solid feedstock i introduced in week "n" (kg).
 $(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock i for week "n" (kg C per kg of feedstock).

$(P_{sp})_{i,n}$ = Mass of solid product i produced in week "n" (kg).
 $(CC_{sp})_{i,n}$ = Average carbon content of solid product i in week "n" (kg C per kg of product).

$$CO_2 = 0.001 * \frac{44}{12} * (C_g + C_l + C_s) \quad (\text{Eq. X-4})$$

Where:

CO_2 = Annual CO_2 mass emissions from process operations and fuel gas combustion (metric tons/year).

0.001 = Conversion factor from kg to metric tons.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of carbon (C) (kg/kg-mole).

(b) If you have an integrated process unit that is determined to be part of the petrochemical production source category, comply with paragraph (a) of this section by including terms for additional carbon-containing products in Equations X-1 through X-3 of this section as necessary.

§ 98.244 Monitoring and QA/QC requirements.

(a) Each facility that uses CEMS to estimate emissions from process vents must comply with the procedures specified in § 98.34(e).

(b) Facilities that use the mass balance methodology in § 98.243(a)(2) must comply with paragraphs (b)(1) through (3) of this section.

(1) Measure the mass rate of each solid feedstock and product (e.g., using belt scales or weighing at the loadout points of your process unit) and record the total for each calendar week. You must document procedures used to ensure the accuracy of the measurements of the feedstock and product flows including, but not limited to, calibration of all weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices shall be recorded, and the technical basis for these estimates shall be recorded.

(2) Measure the volume of each gaseous and liquid feedstock and

product for each process unit continuously with a flow meter. All feedstock and product flow meters must be calibrated prior to the first reporting year, using any applicable method incorporated by reference in § 98.7(b)(1) through (6), (c)(1), (f)(3)(i) through (ii), or (g)(1). You should use the flow meter accuracy test procedures in appendix D to part 75 of this chapter. Alternatively, calibration procedures specified by the equipment manufacturer may be used. Flow meters and gas composition monitors shall be recalibrated annually or at the frequency specified by another applicable rule or the manufacturer, whichever is more frequent.

(3) Collect a sample of each feedstock and product for each process unit at least once per week and determine the carbon content of each sample using an applicable ASTM method incorporated by reference in § 98.7(a)(15), (23), or (24). Alternatively, you may determine the composition of the sample using a gas chromatograph and then calculate the carbon content based on the composition and molecular weights for compounds in the sample. Determine the composition of gas and liquid samples using either: ASTM D1945-03 incorporated by reference in § 98.7 (a)(8) of subpart A of this part; ASTM D6060-96(2001) incorporated by reference in § 98.7; ASTM D2502-88(2004)e1 incorporated by reference in § 98.7; method UOP539-97 incorporated by reference in § 98.7; or EPA Method 18, 40 CFR part 60, appendix A-6; or 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. Calibrate the gas

chromatograph using the procedures in the method prior to each use. 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 weekly period. For carbon black products, samples shall be taken of each grade or type of product produced during the weekly period. Samples of coal feedstock or carbon black product for carbon content determinations may be either grab samples collected and analyzed weekly or a composite of samples collected more frequently and analyzed weekly.

§ 98.245 Procedures for estimating missing data.

(a) 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.

(b) For missing CO_2 concentration, stack gas flow rate, and moisture content for CEMS on any process vent stack, follow the applicable procedures specified in § 98.35.

§ 98.246 Data reporting requirements.

(a) Facilities using the mass balance methodology in § 98.243(a)(2) must report the information specified in paragraphs (a)(1) through (9) of this section for each type of petrochemical produced, reported by process unit.

(1) Identification of the petrochemical process.

(2) Annual CO_2 e emissions calculated using Equation X-4 of this subpart.

(3) Methods used to determine feedstock and product flows and carbon contents.

(4) Number of actual and substitute data points for each measured parameter.

(5) Annual quantity of each feedstock consumed.

(6) Annual quantity of each product and by-product produced, including all products from integrated processes that are part of the petrochemical production source category.

(7) Each carbon content measurement for each feedstock, product, and by-product.

(8) All calculations, measurements, equipment calibrations, certifications, and other information used to assess the uncertainty in emission estimates and the underlying volumetric flow rates, mass flow rates, and carbon contents of feedstocks and products.

(9) Identification of any combustion units that burned process off-gas.

(b) Each facility that uses CEMS to determine emissions from process vents must report the verification data specified in § 98.36(d)(1)(iv).

§ 98.247 Records that must be retained.

In addition to the recordkeeping requirements in § 98.3(g), you must retain the following records:

(a) The CEMS recordkeeping requirements in § 98.37, if you operate a CEMS on process vents.

(b) Results of feedstock or product composition determinations conducted in accordance with § 98.243(a)(2)(iv).

(c) 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(a)(2)(iv) for determining carbon content of feedstock or product.

§ 98.248 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Y—Petroleum Refineries

§ 98.250 Definition of source category.

(a) A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(b) 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; land disposal units; sulfur recovery plants. hydrogen plants (non-merchant plants only).

§ 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 (2).

§ 98.252 GHGs to report.

You must report:

(a) CO₂, CH₄, and N₂O combustion emissions from stationary combustion sources and from each flare. For each stationary combustion unit, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in subpart C of this part.

(b) CO₂, CH₄, and N₂O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit.

(c) CO₂ emissions from sour gas sent off site for sulfur recovery operations. You must follow the calculation procedures from § 98.253(f) of this subpart and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart of this part.

(d) CO₂ process emissions from each on-site sulfur recovery plant.

(e) CO₂, CH₄, and N₂O emissions from each coke calcining unit.

(f) CO₂ emissions from asphalt blowing operations controlled using a combustion device and CH₄ emissions from asphalt blowing operations not controlled by a combustion device.

(g) CH₄ fugitive emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems.

(h) CO₂, CH₄, and N₂O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section.

(i) CH₄ emissions from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(j) CO₂ and CH₄ emissions from on-site wastewater treatment. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting

requirements, and recordkeeping requirements of subpart II of this part.

(k) CO₂ and CH₄ emissions from non-merchant hydrogen production. You must follow the calculation procedures, 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) For stationary combustion sources, if you operate and maintain a CEMS that measures total CO₂ emissions according to subpart C of this part, you must estimate total CO₂ emissions according to the requirements in § 98.33(a)(4).

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) and (2) of this section for combustion systems fired with refinery fuel gas.

(1) Calculate the CO₂ emissions according to the applicable requirements in paragraphs (b)(1)(i) through (iii) of this section.

(i) *Flow measurement.* If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational, to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) *Carbon content.* If you have a continuous higher heating value monitor or carbon content monitor on the flare or if you monitor these parameters at least daily, you must use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare. If you monitor carbon content, calculate the CO₂ emissions from the flare using the applicable equation in § 98.33(a). If you monitor heat content, calculate the CO₂ emissions from the flare using the applicable equation in § 98.33(a) and the default emission factor of 60 kilograms CO₂/MMBtu on a higher heating value basis.

(iii) *Startup, shutdown, malfunction.* If you do not measure the higher heating value or carbon content of the flare gas at least daily, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO₂ emissions as specified in paragraphs (b)(1)(iii)(A) through (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.

(B) For periods of normal operation, use the average heating value measured

for the refinery fuel gas for the heating value of the flare gas.

(C) Calculate the CO₂ emissions using Equation Y-1 of this section.

$$CO_2 = Flare_N * HHV * (0.001 * EmF) + \sum_{p=1}^n \frac{44}{12} * (Flare_{SSM})_p * (CC)_p \quad (\text{Eq. Y-1})$$

Where:

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

Flare_N = 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 refinery fuel or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).

EmF = Default CO₂ emission factor of 60 kilograms CO₂/MMBtu (HHV basis).

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

n = Number of start-up, shutdown, and malfunction events during the reporting year.

p = Start-up, shutdown, and malfunction event index.

44 = Molecular weight of CO₂ (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).

Flare_{SSM} = Volume of flare gas combusted during a start-up, shutdown, or

malfunctions from engineering calculations, (MMscf/event).

(CC)_p = Average carbon content of the gaseous fuel, from the fuel analysis results or engineering calculations for the event (gram C per scf = metric tons C per MMscf).

(2) Calculate CH₄ and N₂O emissions according to the requirements in § 98.33(c)(2) using the emission factors for Refinery Gas in Table C-3 in subpart C of this part.

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (4) of this section.

(1) For catalytic cracking units and fluid coking units that use a continuous CO₂ CEMS for the final exhaust stack, calculate the combined CO₂ emissions from each catalytic cracking or fluid coking unit and CO boiler (if present) using the CEMS according to the Tier 4

Calculation Methodology requirements in § 98.33(a)(4). For units that do not have a CO boiler or other post-combustion device, Equation Y-3 of this section may be used as an alternative to a continuous flow monitor, if one is not already present.

(2) For catalytic cracking units and fluid coking units that do not use a continuous CO₂ CEMS for the final exhaust stack, you must continuously monitor the O₂, CO, and CO₂ 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 (iii) of this section:

(i) Calculate the CO₂ emissions from each catalytic cracking unit and fluid coking unit using Equation Y-2 of this section.

$$CO_2 = \sum_1^n (Q_r)_n * \frac{(\%CO_2 + \%CO)_n}{100\%} * \frac{44}{MVC} * 0.001 \quad (\text{Eq. Y-2})$$

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 no auxiliary fuel is burned and a continuous CO monitor is not required, 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-3 of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. Y-3})$$

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).

%O₂ = 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} = O₂ 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).

%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 no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero.

(iii) If a CO boiler or other post-combustion device is used, calculate the GHG emissions from the fuel fired to the CO boiler or post-combustion device using the methods for stationary combustion sources in paragraph (a) of this section and report this separately for the combustion unit.

(3) Calculate CH₄ emissions using Equation Y-4 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_1}{EmF_2} \right) \quad (\text{Eq. Y-4})$$

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 (kg CO₂/MMBtu).

EmF₂ = Default CH₄ emission factor for petroleum coke from Table C-3 of subpart C of this part (kg CH₄/MMBtu).

(4) Calculate N₂O emissions using Equation Y-5 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_1}{EmF_2} \right) \quad (\text{Eq. Y-5})$$

Where:

N₂O = Annual nitrous oxide emissions from coke burn-off (mt N₂O/year).

EmF₁ = Default CO₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (kg CO₂/MMBtu).

EmF₂ = Default N₂O emission factor for petroleum coke from Table C-3 of subpart C of this part (kg N₂O/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 for 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 CO₂ emissions using either the methods described in paragraphs (e)(1) or (2) of this section and calculate the CH₄ and N₂O emissions using the Equations Y-4 and Y-5 of this section, respectively.

(1) Calculate CO₂ emissions from the catalytic reforming unit catalyst regenerator using the methods in paragraphs (c)(1) or (2) of this section, or

(2) Calculate CO₂ emissions from the catalytic reforming unit catalyst regenerator using Equation Y-6 of this section.

$$CO_2 = \sum_1^n (CB_Q)_n * CF * \frac{44}{12} * 0.001 \quad (\text{Eq. Y-6})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).

CB_Q = Coke burn-off quantity per regeneration cycle (kg coke/cycle).

CF = Site-specific fraction carbon content of produced coke, use 0.94 if site-specific fraction carbon content is unavailable (kg C per kg coke).

44 = Molecular weight of CO₂ (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

n = Number of regeneration cycles in the calendar year.

0.001 = Conversion factor (mt/kg).

(f) For on-site sulfur recovery plants, calculate CO₂ process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (4) of this section. Except as

provided in paragraph (f)(4) 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. For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(1) through (3) of this section is not considered a fuel.

(1) *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.

(2) *Carbon content.* If you have a continuous compositional or carbon content monitor on the sour gas feed to the sulfur recovery plant or if you monitor these parameters on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor or use the default factor of 0.20.

(3) Calculate the CO₂ emissions from each sulfur recovery plant using Equation Y-7 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \quad (\text{Eq. Y-7})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).

F_{SG} = Volumetric flow rate of sour gas feed 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.

(4) As an alternative to the monitoring methods in paragraphs (f)(1) through (3) of this section, you may use a continuous flow monitor and CO₂ CEMS in the final exhaust stack from the sulfur recovery plant according to the requirements in § 98.33(a)(4) to calculate the combined process and combustion emissions for the sulfur recovery plant. 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. You must report 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.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g)(1) through (3) of this section.

(1) For coke calcining units that use a continuous CO₂ CEMS for the final exhaust stack, calculate the combined CO₂ emissions from the coke calcining process and any auxiliary fuel

combusted using the CEMS according to the requirements in § 98.33(a)(4).

(2) For coke calcining units that do not use a continuous CO₂ CEMS for the final exhaust stack, calculate CO₂ emissions from the coke calcining unit according to the requirements in paragraphs (g)(2)(i) and (ii) of this section.

(i) Calculate the CO₂ emissions for any auxiliary fuel fired to the calcining unit using the applicable methods in subpart C of this part.

(ii) Calculate the CO₂ emissions from the coke calcining process using Equation Y-8 of this section.

$$CO_2 = \frac{44}{12} * (M_{in} * CC_{GC} - (M_{out} + M_{dust}) * CC_{MPC}) \quad (\text{Eq. Y-8})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).

Min = 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 (2), as applicable, and calculate CH₄ using Equation Y-4 of this section and N₂O emissions using Equation Y-5 of this section.

(h) For asphalt blowing operations, calculate GHG emissions according to the applicable provisions in paragraphs (h)(1) and (2) of this section.

(1) For uncontrolled asphalt blowing operations, calculate CH₄ emissions using Equation Y-9 of this section.

$$CH_4 = \left(Q_{AB} * EF_{AB} * \frac{16}{MVC} * 0.001 \right) \quad (\text{Eq. Y-9})$$

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} = Emission factor for asphalt blowing from facility-specific test data (scf CH₄/MMbbl); use 2,555,000 scf CH₄/MMbbl if facility-specific test data are unavailable.

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).

(2) For controlled asphalt blowing operations, calculate CO₂ emissions using Equation Y-10 of this section, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section.

$$CO_2 = \left(Q_{AB} * EF_{AB} * \frac{44}{MVC} * 1 * 0.001 \right) \quad (\text{Eq. Y-10})$$

Where:

CO₂ = Annual CO₂ emissions (metric ton/year).

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

EF_{AB} = Default emission factor (2,555,000 scf CH₄/MM bbl).

44 = Molecular weight of CO₂ (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

1 = Assumed conversion efficiency (kg-mole CO₂/kg-mole CH₄).

0.001 = Conversion factor (metric tons/kg).

(i) For delayed coking units, calculate the CH₄ emissions from the

depressurization of the coking unit vessel to atmosphere using the process vent method in paragraph (j) of this section and calculate the CH₄ emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y-11 of this section.

$$CH_4 = \left(N * H * \frac{\pi * D^2}{4} * \frac{16}{MVC} * MF_{CH_4} * 0.001 \right) \quad (\text{Eq. Y-11})$$

Where:

CH₄ = Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).

N = Total number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.

H = Height of coking unit vessel (feet).

D = Diameter of coking unit vessel (feet).

16 = Molecular weight of CH₄ (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

MF_{CH₄} = Mole fraction of methane in coking vessel gas (kg-mole CH₄/kg-mole gas); default value is 0.03.

0.001 = Conversion factor (metric ton/kg).

(j) For each process vent not covered in paragraphs (a) through (i) of this section, calculate GHG emissions using

the Equation Y-12 of this section. You must use Equation Y-12 for catalytic reforming unit depressurization and

purge vents when methane is used as the purge gas.

$$E_x = \sum_{n=1}^N VR_n * MF_x * \frac{MW_x}{MVC} * VT_n * 0.001 \quad (\text{Eq. Y-12})$$

Where:

E_x = Annual emissions of each GHG from process vent (metric ton/yr).

N = Number of venting events per year.

VR_n = Volumetric flow rate of process vent (scf per hour per event).

44 = Molecular weight of CO_2 (kg/kg-mole).

MF_x = Mole fraction of GHG x in process vent.

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_n = Venting time, (hours per event).

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-13 of this section.

$$CH_4 = \left(Q_{\text{Ref}} * EF_{\text{BD}} * \frac{16}{MVC} * 0.001 \right) \quad (\text{Eq. Y-13})$$

Where:

CH_4 = Methane emission rate from blowdown systems (mt CH_4 /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 CH_4 /MMbbl); default is 137,000.

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

(l) For equipment leaks, calculate CH_4 emissions using the method specified in either paragraph (l)(1) or (l)(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-14 of this section.

$$CH_4 = (0.4 * N_{\text{CD}} + 0.2 * N_{\text{PU1}} + 0.1 * N_{\text{PU2}} + 4.3 * N_{\text{H2}} + 6 * N_{\text{FGS}}) \quad (\text{Eq. Y-14})$$

Where:

CH_4 = Annual methane emissions from fugitive 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, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) and (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 TANKS Model (Version 4.09D) or estimate CH_4 emissions from storage tanks using Equation Y-15 of this section.

$$CH_4 = (0.1 * Q_{\text{Ref}}) \quad (\text{Eq. Y-15})$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

0.1 = Default emission factor for storage tanks (metric ton CH_4 /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 CH_4 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-16 of this section.

$$CH_4 = (995,000 * Q_{\text{un}} * \Delta P) * MF_{\text{CH}_4} * \frac{16}{MVC} * 0.001 \quad (\text{Eq. Y-16})$$

Where:

CH_4 = 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_{CH_4} = Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-

mole CH_4 /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 CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).
0.001 = Conversion factor (metric ton/kg).

(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, report zero methane emissions.

§ 98.254 Monitoring and QA/QC requirements.

(a) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, etc.). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(b) 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.

(c) All CO₂ CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in § 98.34(e).

§ 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 each missing value of the heat content, carbon content, or molecular weight of the fuel, 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.

(b) For missing oil and gas flow rates, use the standard missing data procedures in section 2.4.2 of appendix D to part 75 of this chapter.

(c) For missing CO₂, CO, or O₂, CH₄, and N₂O concentrations, stack gas flow rate, and stack gas moisture content values, use the applicable initial missing data procedures in § 98.35 of subpart C of this part.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

(e) For petrochemical production units, use the missing data procedures in subpart X of this part.

(f) For on-site landfills, use the missing data procedures in subpart HH of this part.

(g) For on-site wastewater treatment systems, use the missing data procedures in subpart II 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 (e) of this section.

(a) For combustion sources, including flares, use the data reporting requirements in § 98.36.

(b) For hydrogen plants, use the data reporting requirements in subpart P of this part.

(c) For petrochemical production units, use the data reporting requirements in subpart X of this part.

(d) For on-site landfills, use the data reporting requirements in subpart HH of this part.

(e) For on-site wastewater treatment systems, use the data reporting requirements in subpart II of this part.

(f) For catalytic cracking units, traditional fluid coking units, catalytic reforming units, sulfur recovery plants, and coke calcining 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, catalytic reforming unit, sulfur recovery plant, or coke calcining unit).

(3) Maximum rated throughput of the unit, in bbl/stream day, metric tons sulfur produced/stream day, or metric tons coke calcined/stream day, as applicable.

(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).

(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.

(h) For asphalt blowing operations, the owner or operator shall report:

- (1) The unit ID number (if applicable).
- (2) The quantity of asphalt blown.
- (3) The type of control device used to reduce methane (and other organic) emissions from the unit.

(4) The calculated annual CO₂, CH₄, and N₂O emissions for each unit, expressed in metric tons of each pollutant emitted.

(i) 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 CO₂, CH₄, and N₂O emissions for each unit, expressed in metric tons of each pollutant emitted.

(j) For equipment leaks, storage tanks, uncontrolled blowdown systems, delayed coking units, and loading operations, the owner or operator shall report:

(1) 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.

(2) The method used to calculate equipment leak emissions and the

calculated, cumulative CH₄ emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(3) 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.

(4) The quantity of unstabilized crude oil received during the calendar year and the cumulative CH₄ emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil.

(5) The cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems.

(6) The total number of delayed coking units at the facility, the number of delayed coking drums per unit, the dimensions and annual number of coke-cutting cycles for each drum, and the cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for delayed coking units.

(7) The quantity and types of materials loaded 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.

(8) 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.

Where:

E_m = Annual CO₂ mass emissions from a wet-process phosphoric acid process line m (metric tons).

44/12 = Ratio of molecular weight 44 to 12

(b) Annual phosphoric acid production by concentration of phosphoric acid produced (metric tons).

(c) Annual phosphoric acid production capacity.

(d) Annual arithmetic average percent inorganic carbon in phosphate rock from batch records.

(e) Annual average phosphate rock consumption from monthly measurement records (in metric tons).

§ 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 (h) of this section for each wet-process phosphoric acid production facility:

(a) Total annual CO₂ emissions from all wet-process phosphoric acid process lines (in metric tons).

(b) Phosphoric acid production (by origin of the phosphate rock) and concentration.

(c) Phosphoric acid production capacity (in metric tons/year).

(d) Number of wet-process phosphoric acid process lines.

(e) Monthly phosphate rock consumption (by origin of phosphate rock).

(f) Measurements of percent inorganic carbon in phosphate rock for each batch consumed for phosphoric acid production.

(g) Records of all phosphate rock purchases and/or deliveries (if vertically integrated with a mine).

(h) Documentation of the procedures used to ensure the accuracy of monthly phosphate rock consumption.

§ 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.

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), and operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (6) of this section:

(1) Chemical recovery furnaces at kraft and sodamills (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 (CaCO₃, Na₂CO₃).

§ 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 (2).

§ 98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (h) of this section:

(a) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each kraft or soda chemical recovery furnace.

(b) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each sulfite chemical recovery combustion unit.

(c) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each semichemical chemical recovery combustion unit.

(d) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each kraft or soda pulp mill lime kiln.

(e) CO₂ emissions from addition of makeup chemicals (CaCO₃, Na₂CO₃).

(f) Emissions of CO₂, N₂O, and CH₄ from any other on-site stationary fuel combustion units (boilers, gas turbines, thermal oxiders, and other sources). You

must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart C of this part.

(g) Emissions of CH₄ from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart HH of this part.

(h) Emissions of CH₄ from on-site wastewater treatment. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart II of this part.

§ 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 (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)(2) and (3).

(3) Calculate biogenic CO₂, CH₄, and N₂O emissions 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:

$$CO_2, CH_4, \text{ or } N_2O \text{ from biomass} = \sum_{p=1}^{12} (1 \times 10^{-3}) (907) (Solids)_p * (HHV)_p * EF \quad (\text{Eq. AA-1})$$

Where:

CH₄, or N₂O, from Biomass = Biogenic CO₂, CH₄, or N₂O mass emissions from spent liquor solids combustion (metric tons).

(Solids)_p = Mass of spent liquor solids combusted per month p (short tons per month).

(HHV)_p = High heat value of the spent liquor solids for month p (mmBtu per mass).

EF = Default emission factor for CO₂, CH₄, or N₂O, from Table AA-1 of this subpart (kg CO₂, CH₄, or N₂O per mmBtu).

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

907 = Conversion factor from tons to kilograms.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO₂, CH₄, and N₂O emissions using the procedures in

paragraphs (b)(1) through (4) of this section:

(1) Calculate fossil CO₂ 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)(2).

(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:

$$\text{Biogenic CO}_2 = \sum_{p=1}^{12} \frac{44}{12} * (\text{Solids})_p * (\text{CC})_p \quad (\text{Eq. AA-2})$$

Where:

Biogenic CO₂ = Annual CO₂ mass emissions for spent liquor solids combustion (metric tons).

(Solids)_p = Mass of the spent liquor solids combusted in month p (metric tons per month).

(CC)_p = Carbon content of the spent liquor solids, from the fuel analysis results for the month p (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

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

(4) Calculate CH₄ and N₂O emissions from biomass using Equation AA-1 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 according to the

methodology for stationary combustion sources in § 98.2(b)(4).

(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 (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 of this part 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)(2) and (3); use the default HHV listed in Table C-1 of subpart C of this part 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 calculated as part of the chemical recovery furnace biogenic CO₂ estimates 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:

$$\text{CO}_2 = \left[M_{(\text{CaCO}_3)} * \frac{44}{100} + M_{(\text{Na}_2\text{CO}_3)} * \frac{44}{105.99} \right] * 1000 \text{ kg/metric ton} \quad (\text{Eq. AA-3})$$

Where:

CO₂ = CO₂ mass emissions from makeup chemicals (kilograms/yr).

M (CaCO₃) = Make-up quantity of CaCO₃ used for the reporting year (metric tons).

M (Na₂CO₃) = Make-up quantity of Na₂CO₃ used for the reporting year (metric tons).

44 = Molecular weight of CO₂.

180 = 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) High heat values of black liquor must be determined once per month using TAPPI Method T 684. The mass of spent black liquor solids must be determined once per month using TAPPI Method T 650. Carbon analyses for spent pulping liquor must be

determined once per month using ASTM method D5373-08.

(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 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 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 monthly measurements are determined to be invalid.

(b) For missing spent pulping liquor flow rates, use the lesser value of either the maximum fuel flow rate for the combustion unit, or the maximum flow

rate that the fuel flow 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 (e) of this section for each GHG emission unit listed in § 98.270(b).

(a) Annual emissions of CO₂, biogenic CO₂, CH₄, and N₂O presented by calendar quarter.

(b) Total consumption of all biomass fuels by calendar quarter.

(c) Total annual quantity of spent liquor solids fired at the facility by calendar quarter.

(d) Total annual steam purchases.

(e) Total annual quantities of makeup chemicals (carbonates) used.

§ 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 (h) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO₂) by calendar quarter for each emissions source listed under § 98.270(b) of this subpart.

(b) Monthly total consumption of all biomass fuels for each biomass combustion unit.

(c) Monthly analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(d) Monthly analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfite or semichemical pulp facility.

(e) Monthly quantities of spent liquor solids fired in each chemical recovery furnace and chemical recovery combustion unit.

(f) Monthly and annual steam purchases.

(g) Monthly and annual steam production for each biomass combustion unit.

(h) Monthly 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		

^aIncludes 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 (2).

§ 98.282 GHGs to report.

(a) You must report CO₂ and CH₄ process emissions from all silicon

carbide process units combined, as set forth in this subpart.

(b) You must report CO₂, N₂O, and CH₄ emissions from each stationary combustion unit by following all of the requirements of subpart C of this part.

§ 98.283 Calculating GHG emissions.

You must determine CO₂ emissions in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) If you operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements of § 98.33(b)(5)(iii)(A), (B), and (C), you must estimate total CO₂ emissions according to the requirements

for the Tier 4 Calculation Methodology in § 98.33(a)(4).

(b) If you do not operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements in subpart C of this part, you must calculate the annual process CO₂ emissions from all silicon carbide production processes at the facility combined, using a facility-specific emission factor according to the procedures in paragraphs (b)(1) and (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

determined quarterly and used to

calculate a quarterly CO₂ emissions factor:

$$EF_{CO_2} = 0.65 * CCF * \left(\frac{44}{12} \right) \quad (\text{Eq. BB-1})$$

Where:

EF_{CO₂} = CO₂ emissions factor (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 = Carbon content factor of petroleum coke from the supplier or as measured by the applicable method incorporated by reference in § 98.7.

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

(2) Use Equation BB-2 of this section to calculate CO₂ process emissions (quarterly) from all silicone carbide production:

$$CO_2 = \sum_{n=1}^q [T_n * EF_{CO_2,n}] * \frac{2000}{2205} \quad (\text{Eq. BB-2})$$

Where:

CO₂ = Annual CO₂ mass production emissions (metric tons CO₂/year).

T_n = Petroleum coke consumption in calendar quarter n (tons coke).

EF_{CO₂, n} = CO₂ emissions factor from calendar quarter n (calculated in Equation BB-1 of this section).

2000/2205 = Conversion factor to convert tons to metric tons.

q = Number of quarters.

(c) You must determine annual process CH₄ emissions from all silicon carbide production processes combined using Equation BB-3 of this section:

$$CH_4 = \sum_{n=1}^q [T_n * 10.2] * \frac{2000}{2205} * 0.001 \quad (\text{Eq. BB-3})$$

Where:

CH₄ = Annual CH₄ mass emissions (metric tons CH₄, year).

T_n = Petroleum coke consumption in calendar quarter n (tons coke).

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.

q = Number of quarters.

unacceptable or not representative of typical operations.

§ 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) through (e) of this section.

(a) Annual CO₂ and CH₄ emissions from all silicon carbide production processes combined (in metric tons).

(b) Annual production of silicon carbide (in metric tons).

(c) Annual capacity of silicon carbide production (in metric tons).

(d) Annual operating hours.

(e) Quarterly facility-specific emission factors.

§ 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) through (c) of this section for all silicon carbide production processes combined.

(a) Annual consumption of petroleum coke (in metric tons).

(b) Quarterly analyses of carbon content for consumed coke (averaged to an annual basis).

(c) Quarterly facility-specific emission factor calculations.

§ 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 calcines trona to produce soda ash.

§ 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 (2).

§ 98.292 GHGs to report.

(a) You must report CO₂ process emissions from each soda ash manufacturing line as required in this subpart.

(b) You must report the CO₂, N₂O, and CH₄ emissions from fuel combustion at each kiln and from each stationary combustion unit by following the requirements of subpart C of this part.

§ 98.293 Calculating GHG emissions.

You must determine CO₂ emissions in accordance with the procedures specified in either paragraph (a) or (b) of this section.

§ 98.284 Monitoring and QA/QC requirements.

(a) You must determine the quantity of petroleum coke consumed each quarter (tons coke/quarter).

(b) For CO₂ process emissions, you must determine the carbon content of the petroleum coke for four calendar quarters per year based on reports from the supplier or by measurement of the carbon content by an off-site laboratory using the applicable test method incorporated by reference in § 98.7.

§ 98.285 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. There are no missing value provisions for the carbon content factor or coke consumption. A re-test must be performed if the data from the quarterly carbon content measurements are determined to be

(a) Any soda ash manufacturing line that meets the conditions specified in § 98.33(b)(5)(iii)(A),(B), and (C), or § 98.33(b)(5)(ii)(A) through (F) shall calculate total CO₂ emissions using a continuous emissions monitoring system according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) If the facility does not measure total emissions with a CEMS, you must

determine the total process emissions from the facility using Equation CC-1 of this section:

$$CO_2 = \sum_{k=1}^n E_k \quad (\text{Eq. CC-1})$$

Where:

CO₂ = Annual process CO₂ emissions from soda ash manufacturing facility (metric tons/year).

E_k = Annual CO₂ process emissions from each calciner (kiln), k (in metric tons/year), using either Equation CC-2 or CC-3.

n = Number of calciners (kilns) located at the facility.

(c) Calculate the annual CO₂ process emissions from each kiln using either Equation CC-2 or CC-3 of this section.

$$CO_2 = \sum_{n=1}^{12} \frac{44}{12} * [(IC_T)_n * (T_t)_n] * \frac{2000}{2205} * \frac{0.097}{1} \quad (\text{Eq. CC-2})$$

$$CO_2 = \sum_{n=1}^{12} \frac{44}{12} * [(IC_{sa})_n * (T_{sa})_n] * \frac{2000}{2205} * \frac{0.138}{1} \quad (\text{Eq. CC-3})$$

Where:

CO₂ = Annual CO₂ process emissions (metric tons).

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

(IC_T)_n = Inorganic carbon content in trona input, from the carbon analysis results for month n (percent by weight, expressed as a decimal fraction).

(IC_{sa})_n = Inorganic carbon content in soda ash output, from the carbon analysis results for month n (percent by weight, expressed as a decimal fraction).

(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 natural soda ash produced.

§ 98.294 Monitoring and QA/QC requirements.

(a) You must determine the inorganic carbon content of the trona or soda ash on a daily basis and determine the monthly average value for each soda ash manufacturing line.

(b) If you calculate CO₂ process emissions based on trona input, you must determine the inorganic carbon content of the trona using a total organic carbon analyzer according to the ultraviolet light/chemical (sodium persulfate) oxidation method (utilizing ASTM D4839-03).

(c) If you calculate CO₂ process emissions based on soda ash production, you must determine the inorganic carbon content of the soda ash using ASTM E359-00 (2005). The inorganic carbon content of soda ash can be directly expressed as the total alkalinity of the soda ash.

(d) You must measure the mass of trona input or soda ash produced by each soda ash manufacturing line on a

monthly basis using either belt scales or by weighing the soda ash at the truck or rail loadout points of your facility.

(e) You must keep a record of all trona consumed and soda ash production. You also must document the procedures used to ensure the accuracy of the monthly measurements of trona consumed soda ash production.

§ 98.295 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. There are no missing value provisions for the carbon content of trona or soda ash. A re-test must be performed if the data from the daily carbon content measurements are determined to be unacceptable.

§ 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) through (f) of this section for each soda ash manufacturing line.

(a) Annual CO₂ process emissions (metric tons).

(b) Number of soda ash manufacturing lines.

(c) Annual soda ash production (metric tons) and annual soda ash production capacity.

(d) Annual consumption of trona from monthly measurements (metric tons).

(e) Fractional purity (i.e., inorganic carbon content) of trona or soda ash (by daily measurements and by monthly average) depending on the components used in Equation CC-2 or CC-3 of this subpart).

(f) Number of operating hours in calendar year.

§ 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) through (d) of this section for each soda ash manufacturing line.

(a) Monthly production of soda ash (metric tons).

(b) Monthly consumption of trona (metric tons).

(c) Daily analyses for inorganic carbon content of trona or soda ash (as fractional purity), depending on the components used in Equation CC-2 or CC-3 of this subpart.

(d) Number of operating hours in calendar year.

§ 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—Sulfur Hexafluoride (SF₆) From Electrical Equipment

§ 98.300 Definition of the source category.

The electric power system source category includes electric power transmission and distribution systems that operate gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers containing sulfur-hexafluoride (SF₆) or perfluorocarbons (PFCs).

§ 98.301 Reporting threshold.

You must report GHG emissions from electric power systems if the total nameplate capacity of SF₆ and PFC containing equipment in the system exceeds 17,820 lbs (7,838 kg).

§ 98.302 GHGs to report.

You must report total SF₆ and PFC emissions (including emissions from fugitive equipment leaks, installation,

servicing, equipment decommissioning and disposal, and from storage cylinders) from the following types of equipment:

- (a) Gas-insulated substations.
- (b) Circuit breakers.

- (c) Switchgear.
- (d) Gas-insulated lines.
- (d) Electrical transformers.

§ 98.303 Calculating GHG emissions.

(a) For each electric power system, you must estimate the annual SF₆ and PFC emissions using the mass-balance approach in Equation DD-1 of this section:

$$\begin{aligned} \text{User Emissions} = & (\text{Decrease in SF}_6 \text{ Inventory}) + (\text{Acquisitions of SF}_6) \\ & - (\text{Disbursements of SF}_6) - (\text{Net Increase in Total Nameplate} \\ & \text{Capacity of Equipment Operated}) \end{aligned} \quad (\text{Eq. DD-1})$$

Where:

Decrease in SF₆ Inventory = (SF₆ stored in containers, but not in equipment, at the beginning of the year)—(SF₆ stored in containers, but not in equipment, at the end of the year).

Acquisitions of SF₆ = (SF₆ purchased from chemical producers or distributors in bulk) + (SF₆ purchased from equipment manufacturers or distributors with or inside equipment) + (SF₆ returned to site after off-site recycling).

Disbursements of SF₆ = (SF₆ in bulk and contained in equipment that is sold to other entities) + (SF₆ returned to suppliers) + (SF₆ sent off site for recycling) + (SF₆ sent to destruction facilities).

Net Increase in Total Nameplate Capacity of Equipment Operated = (The Nameplate Capacity of new equipment)—(Nameplate Capacity of retiring equipment). (Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage.)

(b) The mass-balance method in paragraph (a) of this section shall be used to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF₆ in equation DD-1.

§ 98.304 Monitoring and QA/QC requirements.

(a) You must adhere to the following QA/QC methods for reviewing the completeness and accuracy of reporting:

(1) Review inputs to Equation DD-1 to ensure inputs and outputs to the company's system are included.

(2) Do not enter negative inputs and confirm that negative emissions are not calculated. However, the Decrease in SF₆ Inventory and the Net Increase in Total Nameplate Capacity may be calculated as negative numbers.

(3) Ensure that beginning-of-year inventory matches end-of-year inventory from the previous year.

(4) Ensure that in addition to SF₆ purchased from bulk gas distributors, SF₆ purchased from Original Equipment Manufacturers (OEM) and SF₆ returned to the facility from off-site recycling are also accounted for among the total additions.

(b) Ensure the following QA/QC methods are employed throughout the year:

(1) Ensure that cylinders returned to the gas supplier are consistently weighed on a scale that is certified to be accurate and precise to within 1 percent of the true weight and is periodically recalibrated per the manufacturer's specifications. Either measure residual gas (the amount of gas remaining in returned cylinders) or have the gas supplier measure it. If the gas supplier weighs the residual gas, obtain from the gas supplier a detailed monthly accounting, within 1 percent, of residual gas amounts in the cylinders returned to the gas supplier.

(2) Ensure that procedures are in place and followed to track and weigh all cylinders as they are leaving and entering storage. Cylinders shall be weighed on a scale that is certified to be accurate to within 1 percent of the true weight and the scale shall be recalibrated at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. All scales used to measure quantities that are to be reported under § 98.306 shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ISWM, ISDA, NCWM, or others). Alternatively, calibration procedures specified by the scale manufacturer may be used. Calibration shall be performed prior to the first reporting year.

(3) Ensure all substations have provided information to the manager compiling the emissions report (if it is not already handled through an electronic inventory system).

§ 98.305 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for SF₆ and PFC, and from similar equipment repair,

replacement, and maintenance operations.

§ 98.306 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each electric power system, by chemical:

(a) Nameplate capacity of equipment containing SF₆ and nameplate capacity of equipment containing each PFC:

(1) Existing as of the beginning of the year.

(2) New during the year.

(3) Retired during the year.

(b) Transmission miles (length of lines carrying voltages at or above 34.5 kV).

(c) SF₆ and PFC sales and purchases.

(d) SF₆ and PFC sent off site for destruction.

(e) SF₆ and PFC sent off site to be recycled.

(f) SF₆ and PFC returned from off site after recycling.

(g) SF₆ and PFC stored in containers at the beginning and end of the year.

(h) SF₆ and PFC with or inside new equipment purchased in the year.

(i) SF₆ and PFC with or inside equipment sold to other entities.

(j) SF₆ and PFC returned to suppliers.

§ 98.307 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain records of the information reported and listed in § 98.306.

§ 98.308 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

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 (2).

§ 98.312 GHGs to report.

(a) You must report CO₂ process emissions from each chloride process line as required in this subpart.

(b) Report the CO₂, N₂O, and CH₄ emissions from each stationary combustion unit. You must follow the requirements of subpart C of this part.

§ 98.313 Calculating GHG emissions.

You must determine CO₂ emissions for each process line in accordance with the procedures specified in either paragraph (a) or (b) of this section.

(a) If the facility operates and maintains a continuous emission monitoring system (CEMS) that meets the conditions specified in § 98.33(b)(5)(ii) or (iii), then you must calculate total CO₂ emissions using the Tier 4 Calculation Methodology specified in § 98.33(a)(4).

(b) If the facility does not measure total emissions with a CEMS, you must calculate the process CO₂ emissions for each calcined petroleum coke process line by determining the mass of calcined petroleum coke consumed in line. Use Equation EE-1 of this section to calculate annual CO₂ process emissions for each process line:

$$E_p = \sum_{n=1}^{12} \frac{44}{12} * C_n * \frac{2000}{2205} \quad (\text{Eq. EE-1})$$

Where:

E_p = Annual CO₂ mass emissions from each chloride process line (metric tons).

C_n = Calcined petroleum coke consumption in month n, tons.

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

2000/2205 = Conversion of tons to metric tons.

(c) You must determine the total CO₂ process emissions from the facility using Equation EE-2 of this section:

$$\text{CO}_2 = \sum_{p=1}^n E_p \quad (\text{Eq. EE-2})$$

Where:

CO₂ = Annual CO₂ emissions from titanium dioxide production facility (metric tons/year).

E_p = Annual CO₂ emissions from each chloride process line, p (in metric tons/year), determined using Equation EE-1.

n = Number of separate chloride process lines located at the facility.

§ 98.314 Monitoring and QA/QC requirements.

(a) You must measure your consumption of calcined petroleum coke either by 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.

§ 98.315 Procedures for estimating missing data.

There are no missing data procedures for the measurement of petroleum coke consumption. A complete record of all measured parameters used in the GHG emissions calculations is required.

§ 98.316 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information specified in paragraphs (a) through (e) for each titanium dioxide production line.

(a) Annual CO₂ emissions (metric tons).

(b) Annual consumption of calcined petroleum coke (metric tons).

(c) Annual production of titanium dioxide (metric tons).

(d) Annual production capacity of titanium dioxide (metric tons).

(e) Annual operating hours for each titanium dioxide process line.

§ 98.317 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) through (e) of this section for each titanium dioxide production facility.

(a) Monthly production of titanium dioxide (metric tons).

(b) Production capacity of titanium dioxide (metric tons).

(c) Records of all calcined petroleum coke purchases.

(d) Records of monthly calcined petroleum coke consumption (metric tons).

(e) Annual operating hours for each titanium dioxide process line.

§ 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—Underground Coal Mines

§ 98.320 Definition of the source category.

(a) This source category consists of active underground coal mines and any underground mines under development that have operational pre-mining degasification systems. An underground coal mine is a mine at which coal is produced by tunneling into the earth to a subsurface coal seam, where the coal is then mined with equipment such as cutting machines, and transported to the surface. Active underground coal mines are mines categorized by MSHA as active and where coal is currently being produced or has been produced within the previous 90 days.

(b) This source category comprises the following emission points:

(1) Each ventilation well or shaft.

(2) Each degasification system well or shaft, including degasification systems deployed before, during, or after mining operations are conducted in a mine area.

(c) This source category does not include abandoned (closed) mines, surface coal mines, or post-coal mining activities.

§ 98.321 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a underground coal mining process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.322 GHGs to report.

You must report the following:

(a) CH₄ emissions from each ventilation well or shaft and each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area).

(b) CO₂ emissions from coal mine gas CH₄ destruction, where the gas is not a fuel input for energy generation or use.

(c) CO₂, CH₄, and N₂O emissions from stationary fuel combustion devices. You must follow the requirements of subpart C of this part.

§ 98.323 Calculating GHG emissions.

(a) For each ventilation well or shaft, you must estimate the quarterly CH₄ liberated from the mine ventilation system using the measured CH₄ content and flow rate, and Equation FF-1 of this section. You must measure CH₄ content, flow rate, temperature, and pressure of the gas using the procedures outlined in § 98.324.

$$\text{CH}_{4V} = n * \left(V * \frac{C}{100\%} * 0.0423 * \frac{520^{\circ}\text{R}}{T} * \frac{P}{1 \text{ atm}} * 1,440 * \frac{0.454}{1,000} \right) \quad (\text{Eq. FF-1})$$

Where:
 CH_{4V} = Quarterly CH_4 liberated from ventilation systems (metric tons CH_4).
 V = Measured volumetric flow rate of active ventilation of mining operations (cfm).
 C = Measured CH_4 concentration of ventilation gas during active ventilation of mining operations (% wet basis).
 n = The number of days in the quarter where active ventilation of mining operations is taking place.
 0.0423 = Density of CH_4 at 520 °R (60 °F) and 1 atm (lb/scf).
 T = Temperature at which flow is measured (°R).
 P = Pressure at which flow is measured (atm).
 $1,440$ = Conversion factor (min/day).
 $0.454/1,000$ = Conversion factor (metric ton/lb).

(b) For each degasification system, you must estimate the quarterly CH_4 liberated from the mine degasification system using measured CH_4 content, flow rate, temperature, and pressure, and Equation FF-2 of this section.

$$CH_{4D} = n * \left(V * \frac{C}{100\%} * 0.0423 * \frac{520^{\circ}R}{T} * \frac{P}{1 \text{ atm}} * 1,440 * \frac{0.454}{1,000} \right) \quad (\text{Eq. FF-2})$$

Where:
 CH_{4D} = Quarterly CH_4 liberated from the degasification system (metric tons CH_4).
 V = Measured average volumetric flow rate for the days in the quarter when the degasification system is in operation and the continuous monitoring equipment is properly functioning (cfm).
 C = Estimated or measured average CH_4 concentration of gas for the days in the quarter when the degasification system is in operation and the continuous monitoring equipment is properly functioning (% wet basis).
 n = The number of days in the quarter.
 0.0423 = Density of CH_4 at 520 °R (60 °F) and 1 atm (lb/scf).
 T = Measured average temperature at which flow is measured (°R).
 P = Measured average pressure at which flow is measured (atm).
 $1,440$ = Conversion factor (min/day).
 $0.454/1,000$ = Conversion factor (metric ton/lb).

(c) If gas from degasification system wells or ventilation shafts is destroyed you must calculate the quarterly CH_4 destroyed using Equation FF-3 of this section. You must measure CH_4 content and flowrate according to the provisions in § 98.324.

$$CH_4 \text{ destroyed} = CH_4 \times DE/100 \quad (\text{Eq. FF-3})$$

Where:
 CH_4 destroyed = Quantity of CH_4 liberated from mine that is destroyed (metric tons).
 CH_4 = Amount of CH_4 collected for destruction (metric tons).
 DE = Destruction efficiency of the destruction equipment, based on the lesser of the manufacturer's specified destruction efficiency or 98 percent (%).

(d) You must calculate the quarterly net CH_4 emissions to the atmosphere using Equation FF-3 of this section.

$$CH_4 \text{ emitted (net)} = CH_{4V} + CH_{4D} - CH_4 \text{ destroyed} \quad (\text{Eq. FF-4})$$

Where:
 CH_4 emitted (net) = Quarterly CH_4 emissions from mine ventilation and degasification systems (metric tons).
 CH_{4V} = Quarterly CH_4 liberated from mine ventilation systems, calculated using Equation FF-1 of this section (metric tons).
 CH_{4D} = Quarterly CH_4 liberated from mine degasification systems, calculated using Equation FF-2 of this section (metric tons).
 CH_4 destroyed = Quarterly CH_4 destroyed, calculated using Equation FF-3 of this section (metric tons).

(e) For each degasification or ventilation system with on-site coal mine gas CH_4 destruction, where the gas is not a fuel input for energy generation or use, you must estimate the CO_2 emissions using Equation FF-5 of this section. You must measure the CH_4 content and the flow rate according to the provisions in § 98.324.

$$CO_2 = CH_{4o} * 44/16 \quad (\text{Eq. FF-5})$$

Where:
 CO_2 = Quarterly CO_2 emissions from CH_4 destruction (metric tons).

CH_{4o} = CH_4 destroyed, calculated using Equation FF-3 of this section (metric tons).
 DE = Destruction efficiency, based on the lesser of the manufacturer's specified destruction efficiency or 98 percent (%).
 $44/16$ = Ratio of molecular weights of CO_2 to CH_4 .

§ 98.324 Monitoring and QA/QC requirements.

(a) The flow and CH_4 content of coal mine gas destroyed must be determined using ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).

(b) For liberation of methane from ventilation systems, you must do one of the following:

(1) Monitor emissions from each well or shaft where active ventilation is taking place by collecting quarterly grab samples and making quarterly measurements of flow rate, temperature, and pressure. The sampling and measurements must be made at the same location as MSHA inspection samples are taken. You must follow MSHA sampling procedures as set forth in the MSHA Handbook entitled, General Coal Mine Inspection Procedures and Inspection Tracking System Handbook Number: PH-08-V-1, January 1, 2008. You must record the airflow, temperature, and pressure measured, the hand-held methane and oxygen readings in percentile, the bottle number of samples collected, and the location of the measurement or collection.

(2) Obtain results of the quarterly testing performed by MSHA.

(c) For liberation of methane at degasification systems, you must monitor methane concentrations and flow rate from each degasification well or shaft using any of the oil and gas flow

meter test methods incorporated by reference in § 98.7.

(d) All fuel flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, MSHA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer or other applicable standards.

(e) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(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, and the technical basis for the estimated accuracy shall be recorded.

§ 98.325 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, in accordance with paragraph (b) of this section.

(b) For each missing value of CH₄ concentration, flow rate, temperature, and pressure for ventilation and degasification systems, 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.

§ 98.326 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report

must contain the following information for each mine:

(a) Quarterly volumetric flow rate measurement results for all ventilation systems, including date and location of measurement.

(b) Quarterly CH₄ concentration measurement results for all ventilation systems, including date and location of measurement.

(c) Quarterly CEMS volumetric flow data used to calculate CH₄ liberated from degasification systems (summed from daily data).

(d) Quarterly CEMS CH₄ concentration data used to calculate CH₄ liberated from degasification systems (average from daily data).

(e) Quarterly CH₄ destruction at ventilation and degasification systems.

(f) Dates in reporting period where active ventilation of mining operations is taking place.

(g) Dates in reporting period when continuous monitoring equipment is not properly functioning.

(h) Quarterly averages of temperatures and pressures at the time and at the conditions for which all measurements are made.

(i) Quarterly CH₄ liberated from each ventilation well or shaft, and from each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area).

(j) Quarterly CH₄ emissions (net) from each ventilation well or shaft, and from each degasification system (this includes degasification systems deployed before, during, or after mining operations are conducted in a mine area).

(k) Quarterly CO₂ emissions from on-site destruction of coal mine gas CH₄, where the gas is not a fuel input for energy generation or use.

§ 98.327 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Calibration records for all monitoring equipment.

(b) Records of gas sales.

(c) Logbooks of parameter measurements.

(d) Laboratory analyses of samples.

§ 98.328 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

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.

(a) You must report the CO₂ process emissions from each Waelz kiln and electrothermic furnace used for zinc production, as applicable to your facility.

(a) You must report the CO₂, CH₄, and N₂O emissions from each stationary combustion unit, following requirements of subpart C of this part.

§ 98.333 Calculating GHG emissions.

(a) If you operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements in subpart C of this part, you must estimate total CO₂ emissions according to the requirements in § 98.33(a).

(b) If you do not operate and maintain a CEMS that measures total CO₂ emissions consistent with the requirements in subpart C of this part, you must determine the total CO₂ emissions from the Waelz kilns or electrothermic furnaces at your facility used for zinc production using the procedures specified in paragraphs (b)(1) and (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 calendar month and estimate total annual CO₂ process emissions from each affected unit at your facility using Equation GG-1. 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.

$$E_{\text{CO}_2} = \sum_{n=1}^{12} \frac{44}{12} * \left[(Zinc)_n * (C_{Zinc})_n + (Flux)_n * (C_{Flux})_n + (Electrode)_n * (C_{Electrode})_n + (Carbon)_n * (C_c) \right] \quad (\text{Eq. GG-1})$$

Where:

E_{CO_2} = Total CO₂ process emissions from an individual Waelz kiln or electrothermic furnace (metric tons per year).

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

(Zinc)_n = Mass of zinc bearing material charged to the furnace in month "n" (metric tons).

(C_{Zinc})_n = Carbon content of the zinc bearing material, from the carbon analysis results for month "n" (percent by weight, expressed as a decimal fraction).

(Flux)_n = Mass of flux materials (e.g., limestone, dolomite) charged to the furnace in month "n" (metric tons).

(C_{Flux})_n = Average carbon content of the flux materials, from the carbon analysis results for month "n" (percent by weight, expressed as a decimal fraction).

(Electrode)_n = Mass of carbon electrode consumed in month "n", for electrothermic furnace (metric tons).

(C_{Electrode})_n = Average carbon content of the carbon electrode, from the carbon analysis results for month "n", for electrothermic furnace (percent by weight, expressed as a decimal fraction).

(Carbon)_n = Mass of carbonaceous materials (e.g., coal, coke) charged to the furnace in month "n" (metric tons).

(C_{Carbon})_n = Average carbon content of the carbonaceous materials, from the carbon analysis results for month "n" (percent by weight, expressed as a decimal fraction).

(2) You must determine the total CO₂ emissions from the Waelz kilns or electrothermic furnaces at your facility using Equation GG-2 of this section.

$$CO_2 = \sum_1^k E_{CO_2k} \quad (\text{Eq. GG-2})$$

Where:

CO₂ = Total annual CO₂ emissions, metric tons/year.

E_{CO_2k} = Annual CO₂ emissions from Waelz kiln or electrothermic furnace k calculated using Equation GG-1 of this section, metric tons/year.

k = Total number of Waelz kilns or electrothermic furnaces at facility used for the zinc production.

§ 98.334 Monitoring and QA/QC requirements.

If you determine CO₂ emissions using the carbon input procedure in § 98.333(b)(1), you must meet the requirements specified in paragraphs (a) through (c) of this section.

(a) Determine the mass of each solid carbon-containing input material by direct measurement of the quantity of the material placed in the unit or by calculations using process operating information, and record the total mass for the material for each calendar month.

(b) For each input material identified in paragraph (a) of this section, you

must determine the average carbon content of the material for each calendar month using information provided by your material supplier or by collecting and analyzing a representative sample of the material using an analysis method appropriate for the material.

(c) For each input material identified in paragraph (a) of this section for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed by an independent certified laboratory each calendar month using the test methods (and their QA/QC procedures) in § 98.7. Use ASTM E1941-04 ("Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys") for analysis of zinc bearing materials; ASTM D5373-02 ("Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke") for analysis of carbonaceous reducing agents and carbon electrodes, and ASTM C25-06 ("Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime") for analysis of 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.

(a) For each missing value of the carbon 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, 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 records of the mass of carbon-containing input material consumption, the substitute data value shall be the best available estimate of the mass of the input material. The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 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) through (e) of this section for each Waelz kiln or electrothermic furnace.

(a) Annual CO₂ emissions in metric tons, and the method used to estimate emissions.

(b) Annual zinc product production capacity (in metric tons).

(c) Total number of Waelz kilns and electrothermic furnaces at the facility.

(d) Number of facility operating hours in calendar year.

(e) If you use the carbon input procedure, report for each carbon-containing input material consumed or used (other than fuel), the information specified in paragraphs (e)(1) and (2) of this section.

(1) Annual material quantity (in metric tons).

(2) Annual average of the monthly carbon content determinations for each material and the method used for the determination (e.g., supplier provided information, analyses of representative samples you collected).

§ 98.337 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 (d) of this section.

(a) Monthly facility production quantity for each zinc product (in metric tons).

(b) Number of facility operating hours each month.

(c) Annual production quantity for each zinc product (in metric tons).

(d) If you use the carbon input procedure, record for each carbon-containing input material consumed or used (other than fuel), the information specified in paragraphs (d)(1) and (2) of this section.

(1) Monthly material quantity (in metric tons).

(2) Monthly average carbon content determined for material and records of the supplier provided information or analyses used for the determination.

(e) 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. 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—Landfills**§ 98.340 Definition of the source category.**

(a) This source category consists of the following sources at municipal solid waste (MSW) landfill facilities: landfills, landfill gas collection systems, and landfill gas combustion systems (including flares). This source category also includes industrial landfills (including, but not limited to landfills located at food processing, pulp and paper, and ethanol production facilities).

(b) This source category does not include hazardous waste landfills and construction and demolition landfills.

§ 98.341 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a landfill process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 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 CO₂, CH₄, and N₂O emissions from stationary fuel combustion devices. This includes

emissions from the combustion of fuels used in flares (e.g., for pilot gas or to supplement the heating value of the landfill gas). Follow the requirements of subpart C of this part. Do not calculate CO₂ emissions resulting from the flaring of landfill gas.

§ 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 (4) of this section.

(1) Calculate annual modeled CH₄ generation using recorded or estimated waste disposal quantities, default values from Table HH-1, and Equation HH-1 of this section.

$$G_{CH_4} = \left[\sum_{x=S}^{T-1} \left\{ W_x L_{0,x} \left(e^{-k(T-x-1)} - e^{-k(T-x)} \right) \right\} \right] \quad (\text{Eq. HH-1})$$

Where:

G_{CH_4} = Modeled methane generation rate in reporting year T (metric tons CH₄).

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 = CH₄ generation potential (metric tons CH₄/metric ton waste) = $MCF \cdot DOC \cdot DOC_F \cdot F \cdot 16/12$.

MCF = Methane correction factor (fraction).

DOC = Degradable organic carbon [fraction (metric tons C/metric ton waste)].

DOC_F = Fraction of DOC dissimilated (fraction).

F = Fraction by volume of CH₄ in landfill gas.

k = Rate constant (yr⁻¹).

(2) For years when material-specific waste quantity data are available, and for industrial waste landfills, 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. 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. For both MSW and industrial landfills, 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 L_0 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 for MSW landfills, W_x shall be estimated using the estimated population served by the landfill in each year, the values for national average per capita waste disposal and fraction of generated waste disposed of in solid waste disposal sites found in Table HH-2 of this subpart.

(4) For industrial landfills, W_x in reporting years must be determined by direct mass measurement of waste entering the landfill using industrial scales with a manufacturer's stated accuracy of ±2 percent. For previous years, where data are unavailable on waste disposal quantities, estimate the waste quantities according to the requirements in paragraphs (a)(4)(i) and (ii) of this section.

(i) Calculate the average waste disposal rate per unit of production for the first applicable reporting year using Equation HH-2 of this section.

$$WDF = \left[\sum_{n=1}^N \left\{ \frac{W_n}{N \cdot P_n} \right\} \right] \quad (\text{Eq. HH-2})$$

Where:

WDF = Average waste disposal factor determined on the first year of reporting (metric tons per production unit). The average waste disposal factor should not

be re-calculated in subsequent reporting years.

N = Number of years for which disposal and production data are available.

W_n = Quantity of waste placed in the industrial landfill in year n (metric tons).

P_n = Quantity of product produced in year n (production units).

(ii) Calculate the waste disposal quantities for historic years in which direct waste disposal measurements are not available using historical production data and Equation HH-3 of this section.

$$W_x = WDF \cdot P_x \quad (\text{Eq. HH-3})$$

Where:

X = Historic year in which waste was disposed.

W_x = Projected quantity of waste placed in the landfill in year X (metric tons).

WDF = Average waste disposal factor from Equation HH-1 of this section (metric tons per production unit).

P_x = Production quantity for the facility in year X from company records (production units).

(b) For landfills with gas collection systems, calculate the quantity of CH₄ destroyed according to the requirements in paragraphs (b)(1) through (4) of this section.

(1) Measure continuously the flow rate, CH₄ concentration, temperature, and pressure, of the collected landfill gas (before any treatment equipment) using a monitoring meter specifically for CH₄ gas, as specified in § 98.344.

(2) Calculate the quantity of CH₄ recovered for destruction using Equation HH-4 of this section.

$$R = \sum_{n=1}^{365} \left(V_n * \frac{C_n}{100\%} * 0.0423 * \frac{520^\circ R}{T_n} * \frac{P_n}{1 \text{ atm}} * 1,440 * \frac{0.454}{1,000} \right) \quad (\text{Eq. HH-4})$$

Where:

R = Annual quantity of recovered CH₄ (metric tons CH₄).

V_n = Daily average volumetric flow rate for day n (acfm).

C_n = Daily average CH₄ concentration of landfill gas for day n (% wet basis).

0.0423 = Density of CH₄ lb/scf (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).

(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 (d)(1) through (4) of this section.

(1) Calculate CH₄ generation, adjusted for oxidation, from the modeled CH₄ (GCH₄ from Equation HH-1) using Equation HH-5 of this section.

$$MG = G_{CH_4} * (1 - OX) \quad (\text{Eq. HH-5})$$

Where:

MG = Methane generation from the landfill in the reporting year, adjusted for oxidation (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 default rate is 0.1 (10%).

(2) For landfills that do not have landfill gas collection systems, the CH₄ emissions are equal to the CH₄ generation 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 (ii) of this section.

(i) Calculate CH₄ emissions from the modeled CH₄ generation and measured CH₄ recovery using Equation HH-6 of this section.

$$\text{Emissions} = [(G_{CH_4} - R) * (1 - OX) + R * (1 - DE)] \quad (\text{Eq. HH-6})$$

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 default rate is 0.1 (10%).

DE = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99)

(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.

$$MG = \frac{R}{CE} * (1 - OX) \quad (\text{Eq. HH-7})$$

$$\text{Emissions} = \left[\left(\frac{R}{CE_{CH_4}} - R \right) * (1 - OX) + R * (1 - DE) \right] \quad (\text{Eq. HH-8})$$

Where:

MG = Methane generation 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. (Default is 0.75).

OX = Oxidation fraction (default rate is 0.1 (10%).)

DE = Destruction efficiency, (lesser of manufacturer's specified destruction efficiency and 0.99).

§ 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, 2008.

(b) The quantity of landfill gas CH₄ destroyed must be determined using ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).

(c) All fuel flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by

Gas Chromatography; ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(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, 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, 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 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) Waste disposal for each year of landfilling.
- (b) Method for estimating waste disposal.
- (c) Waste composition, if available, in percentage categorized as—
 - (1) Municipal,
 - (2) Construction and demolition,
 - (3) Biosolids or biological sludges,
 - (4) Industrial, inorganic,
 - (5) Industrial, organic,
 - (6) Other, or more refined categories, such as those for which k rates are available in Table HH–1 of this subpart.
- (d) Method for estimating waste composition.
- (e) Fraction of CH₄ in landfill gas based on measured values if the landfill has a gas collection system or a default.
- (f) Oxidation fraction used in the calculations.
- (g) Degradable organic carbon (DOC) used in the calculations.
- (h) Decay rate k used in the calculations.
- (i) Fraction of DOC dissimilated used in the calculations.
- (j) Methane correction factor used in the calculations.
- (k) Annual methane generation and methane emissions (metric tons/year) according to the methodologies in § 98.343(c)(1) through (3). Landfills with gas collection system must separately report methane generation and emissions according to the methodologies in § 98.343(c)(3)(i) and

(ii) and indicate which values are calculated using the methodologies in § 98.343(c)(ii).

- (l) Landfill design capacity.
 - (m) Estimated year of landfill closure.
 - (n) Total volumetric flow of landfill gas for landfills with gas collection systems.
 - (o) CH₄ concentration of landfill gas for landfills with gas collection systems.
 - (p) Monthly average temperature at which flow is measured for landfills with gas collection systems.
 - (q) Monthly average pressure at which flow is measured for landfills with gas collection systems.
 - (r) Destruction efficiency used for landfills with gas collection systems.
 - (s) Methane destruction for landfills with gas collection systems (total annual, metric tons/year).
 - (t) Estimated gas collection system efficiency for landfills with gas collection systems.
 - (u) Methodology for estimating gas collection system efficiency for landfills with gas collection systems.
 - (v) Cover system description.
 - (w) Number of wells in gas collection system.
 - (x) Acreage and quantity of waste covered by intermediate cap.
 - (y) Acreage and quantity of waste covered by final cap.
 - (z) Total CH₄ generation from landfills.
 - (aa) Total CH₄ emissions from landfills.
- § 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.
- § 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)	0.02	yr ⁻¹
k (precipitation 20–40 inches/year)	0.038	yr ⁻¹
k (precipitation >40 inches/year)	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 and industrial waste landfills		
MCF	1	
DOC _F	0.5	
F	0.5	

TABLE HH-1 OF SUBPART HH—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS—Continued

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
Waste model—Industrial waste landfills		
DOC (food processing)	0.15	Weight fraction, wet basis.
DOC (pulp and paper)	0.2	Weight fraction, wet basis.
k (food processing)	0.185	yr ⁻¹
k (pulp and paper)	0.06	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 the greater value when it does not.

TABLE HH-2 OF SUBPART HH—U.S. PER CAPITA WASTE DISPOSAL RATES

Year	Waste per capita ton/cap/yr	% to SWDS
1940	0.64	100
1941	0.64	100
1942	0.64	100
1943	0.64	100
1944	0.63	100
1945	0.64	100
1946	0.64	100
1947	0.63	100
1948	0.63	100
1949	0.63	100
1950	0.63	100
1951	0.63	100
1952	0.63	100
1953	0.63	100
1954	0.63	100
1955	0.63	100
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

TABLE HH-2 OF SUBPART HH—U.S. PER CAPITA WASTE DISPOSAL RATES—Continued

Year	Waste per capita ton/cap/yr	% to SWDS
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
2002	1.06	66
2003	1.06	65
2004	1.06	64
2005	1.06	64
2006	1.06	64

Subpart II—Wastewater Treatment

§ 98.350 Definition of source category.

(a) A wastewater treatment system is the collection of all processes that treat or remove pollutants and contaminants, such as soluble organic matter, suspended solids, pathogenic organisms, and chemicals from waters released from industrial processes. This source category applies to on-site wastewater treatment systems at pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities.

(b) This source category does not include centralized domestic wastewater treatment plants.

§ 98.351 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a wastewater treatment process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.352 GHGs to report.

(a) You must report annual CH₄ emissions from anaerobic wastewater treatment processes.

(b) You must report annual CO₂ emissions from oil/water separators at petroleum refineries.

(c) You must report CO₂, CH₄, and N₂O emissions from the combustion of fuels in stationary combustion devices and fuels used in flares by following the requirements of subpart C of this part.

For flares, calculate the CO₂ emissions only from pilot gas and other auxiliary fuels combusted in the flare, as specified in subpart C of this part. Do not include CO₂ emissions resulting from the combustion of anaerobic digester gas.

§ 98.353 Calculating GHG emissions.

(a) Estimate the annual CH₄ mass emissions from systems other than digesters using Equation II-1 of this section. The value of flow and COD must be determined in accordance with the monitoring requirements specified in § 98.354. The flow and COD should reflect the wastewater treated anaerobically on site in anaerobic systems such as lagoons.

$$CH_4 = \sum_{n=1}^{12} [Flow_n * COD * B_0 * MCF * 0.001] \quad (\text{Eq. II-1})$$

Where:

CH₄ = Annual CH₄ mass emissions from the wastewater treatment system (metric tons).

Flow_n = Volumetric flow rate of wastewater sent to an anaerobic treatment system in month n (m³/month).

COD = Average monthly value for chemical oxygen demand of wastewater entering

anaerobic treatment systems other than digesters (kg/m³).

B₀ = Maximum CH₄ producing potential of wastewater (kg CH₄/kg COD), default is 0.25.

MCF = CH₄ conversion factor, based on relevant values in Table II-1.
0.001 = Conversion factor from kg to metric tons.

(b) For each petroleum refining facility having an on-site oil/water separator, estimate the annual CO₂ mass emissions using Equation II-2 using measured values for the volume of

wastewater treated, and default values for emission factors by separator type from Table II-1 of this subpart. The flow should reflect the wastewater treated in the oil/water separator.

$$\text{CO}_2 = \sum_{n=1}^{12} \left[\text{EF}_{\text{sep}} * V_{\text{H}_2\text{O}} * C * \frac{44}{12} * 0.001 \text{ metric tons CH}_4/\text{kg} \right] \quad (\text{Eq. II-2})$$

Where:

CO₂ = Annual emissions of CO₂ from oil/water separators (metric tons/yr).
EF_{sep} = Emissions factor for the type of separator (kg NMVOC/m³ wastewater treated).
V_{H₂O} = Volumetric flow rate of wastewater treated through oil/water separator in month m (m³/month).
C = Carbon fraction in NMVOC (default = 0.6).

44/12 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor from kg to metric tons.
(c) For each anaerobic digester, estimate the annual mass of CH₄ destroyed using Equations II-3 and II-4 of this section.

$$\text{CH}_4\text{d} = \text{CH}_4\text{AD} * \text{DE} \quad (\text{Eq. II-3})$$

Where:

CH₄d = Annual quantity of CH₄ destroyed (kg/yr).
CH₄AD = Annual quantity of CH₄ generated by anaerobic digester, as calculated in Equation II-4 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).

$$\text{CH}_4\text{AD} = \sum_{n=1}^{365} \left[V_n * \frac{C_n}{100\%} * 0.0423 * \frac{520 \text{ R}}{T_n} * \frac{P_n}{1 \text{ atm}} * 1,440 \text{ minutes/day} * \frac{0.454 \text{ metric ton}}{1,000 \text{ pounds}} \right] \quad (\text{Eq. II-4})$$

Where:

CH₄AD = Annual quantity of CH₄ generated by anaerobic digestion (metric tons CH₄/yr).
V_n = Daily average volumetric flow rate for day n, as determined from daily monitoring specified in § 98.354 (acfm).
C_n = Daily average CH₄ concentration of digester gas for day n, as determined from daily monitoring specified in § 98.354 (% wet basis).
0.0423 = Density of CH₄ lb/scf (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).

§ 98.354 Monitoring and QA/QC requirements.

(a) The quantity of COD treated anaerobically must be determined using analytical methods for industrial wastewater pollutants and must be conducted in accordance with the methods specified in 40 CFR part 136.

(b) All flow meters must be calibrated using the procedures and frequencies specified by the device manufacturer.

(c) For anaerobic treatment systems, facilities must monitor the wastewater flow and COD no less than once per week. The sample location must represent the influent to anaerobic treatment for the time period that is monitored. The flow sample must correspond to the location used to measure the COD. Facilities must collect 24-hour flow-weighted composite samples, unless they can demonstrate that the COD concentration and wastewater flow into the anaerobic

treatment system does not vary. In this case, facilities must collect 24-hour time-weighted composites to characterize changes in wastewater due to production fluctuations, or a grab sample if the influent flow is equalized resulting in little variability.

(d) For oil/water separators, facilities must monitor the flow no less than once per week. The sample location must represent the influent to oil/water separator for the time period that is monitored.

(e) The quantity of gas destroyed must be determined using any of the oil and gas flow meter test methods incorporated by reference in § 98.7.

(f) All gas flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Gas flow meters and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(g) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the device manufacturer.

(h) All equipment (temperature and pressure monitors and gas flow meters and gas composition monitors) shall be maintained as specified by the manufacturer.

(i) 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 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.

§ 98.355 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 following requirements in paragraphs (a) and (b) of this section:

(a) For each missing monthly value of COD or wastewater flow treated, the substitute data value shall be the arithmetic average of the quality-assured values of those parameters for the weeks immediately preceding and immediately following the missing data incident. For each missing value of the CH₄ content or 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.

(b) 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.

§ 98.356 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for the wastewater treatment system.

- (a) Type of wastewater treatment system.
- (b) Percent of wastewater treated at each system component.
- (c) COD.
- (d) Influent flow rate.

- (e) B₀.
- (f) MCF.
- (g) Methane emissions.
- (h) Type of oil/water separator (petroleum refineries).
- (i) Emissions factor for the type of separator (petroleum refineries).
- (j) Carbon fraction in NMVOC (petroleum refineries).
- (k) CO₂ emissions (petroleum refineries).
- (l) Total volumetric flow of digester gas (facilities with anaerobic digesters).
- (m) CH₄ concentration of digester gas (facilities with anaerobic digesters).
- (n) Temperature at which flow is measured (facilities with anaerobic digesters).

- (o) Pressure at which flow is measured (facilities with anaerobic digesters).
- (p) Destruction efficiency used (facilities with anaerobic digesters).
- (q) Methane destruction (facilities with anaerobic digesters).
- (r) Fugitive methane (facilities with anaerobic digesters).

§ 98.357 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.

§ 98.358 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE II-1 OF SUBPART II—EMISSION FACTORS

Factors	Default value	Units
B ₀	0.25	Kg CH ₄ /kg COD.
MCF—anaerobic deep lagoon, anaerobic reactor (e.g., upflow anaerobic sludge blanket, fixed film)	0.8	Fraction.
MCF—anaerobic shallow lagoon (less than 2 m)	0.2	Fraction.
MCF—centralized aerobic treatment system, well managed	0	Fraction.
MCF—Centralized aerobic treatment system, not well managed (overloaded)	0.3	Fraction.
Anaerobic digester for sludge	0.8	Fraction.
C fraction in NMOC	0.6	Fraction.
EF sep—Gravity Type (Uncovered)	1.11E-01	Kg NMVOC/m ³ wastewater
EF sep—Gravity Type (Covered)	3.30E-03	Kg NMVOC/m ³ wastewater.
EF sep—Gravity Type—(Covered and Connected to a Destruction Device)	0	Kg NMVOC/m ³ wastewater.
DAF or IAF—uncovered	4.00E-34	Kg NMVOC/m ³ wastewater.
DAF or IAF—covered	1.20E-44	Kg NMVOC/m ³ wastewater.
DAF or IAF—covered and connected to a destruction device	0	Kg NMVOC/m ³ wastewater.

DAF = dissolved air flotation type.
IAF = induced air flotation type.

Subpart JJ—Manure Management

§ 98.360 Definition of the source category.

- (a) This source category consists of manure management systems for livestock manure.
- (b) A manure management system is as a system that stabilizes or stores livestock manure in one or more of the following system components: uncovered anaerobic lagoons, liquid/slurry systems, storage pits, digesters, drylots, solid manure storage, feedlots and other dry lots, high rise houses for poultry production (poultry without litter), poultry production with litter, deep bedding systems for cattle and swine, and manure composting. This definition of manure management system encompasses the treatment of wastewaters from manure.
- (c) This source category does not include components at a livestock operation unrelated to the stabilization or storage of manure such as daily

spread or pasture/range/paddock systems.

§ 98.361 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a manure management system and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.362 GHGs to report.

- (a) You must report annual aggregate CH₄ and N₂O emissions for each of the following manure management system (MMS) components at the facility:
 - (1) Liquid/slurry systems such as tanks and ponds.
 - (2) Storage pits.
 - (3) Uncovered anaerobic lagoons used for stabilization or storage or both.
 - (4) Digesters, including covered anaerobic lagoons.
 - (5) Solid manure storage including feedlots and other dry lots, high rise houses for caged laying hens, broiler

and turkey production on litter, and deep bedding systems for cattle and swine.

(6) Manure composting.

(b) You must report CO₂, CH₄, and N₂O emissions from the combustion of supplemental fuels used in flares by following the requirements of subpart C of this part. For flares, calculate the CO₂ emissions only from pilot gas and other auxiliary fuels combusted in the flare, as specified in subpart C of this part. Do not include CO₂ emissions resulting from the combustion of digester gas in flares.

(c) A facility that is subject to this rule only because of emissions from manure management systems is not required to report emissions from fuels used in stationary combustion devices other than flares.

§ 98.363 Calculating GHG emissions.

(a) For manure management systems except digesters, estimate the annual CH₄ emissions using Equation JJ-1.

$$\text{CH}_4 \text{ Emissions (kg/yr)} = \sum_{\text{animal type}} \left[\sum_{\text{MMS}} [\text{TVS} \star \text{VS}_{\text{MMS}} \star 365.25 \text{ days/yr} \star \text{B}_0 \star \text{MCF}_{\text{MMS}}] \star 0.662 \text{ kg CH}_4/\text{m}^3 \right] \quad (\text{Eq. JJ-1})$$

Where:

TVS = Total volatile solids excreted by animal type, calculated using Equation JJ-2 of this section (kg/day).

VS_{MMS} = Percent of manure that is managed in each MMS (decimal) (assumed to be equivalent to the amount of VS in each system).

B₀ = Maximum CH₄-producing capacity, as specified in Table JJ-1 of this section (m³ CH₄/kg VS).
MCF_{MMS} = CH₄ conversion factor for MMS, as specified in Table JJ-2 of this section (decimal).

$$\text{TVS} = \% \text{TVS} \star (\text{Population} \star \text{TAM} \star \text{MER} / 1000) \quad (\text{Eq. JJ-2})$$

Where:

TVS = Total volatile solids excreted per animal type (kg/day).

%TVS = Annual average percent total volatile solids by animal type, as determined from monthly manure monitoring as specified in § 98.364 (decimal).

Population = Average annual animal population (head).

TAM = Typical animal mass, using either default values in Table JJ-1 of this section or farm-specific data (kg/head).

MER = Manure excretion rate, using either default values in Table JJ-1 of this section or farm-specific data (kg manure/day/1,000 kg animal mass).

(b) For each digester, estimate the annual CH₄ flow to the combustion device using Equation JJ-3 of this section, the amount of CH₄ destroyed using Eq JJ-4 of this section, and the amount of CH₄ leakage using Equation JJ-5 of this section.

$$\text{CH}_4 \text{D} = \sum_{n=1}^{365} \left(V_n \star \frac{C_n}{100\%} \star 0.0423 \star \frac{520^\circ\text{R}}{T_n} \star \frac{P_n}{1 \text{ atm}} \star 1,440 \text{ minutes/day} \star \frac{0.454 \text{ metric ton}}{1,000 \text{ pounds}} \right) \quad (\text{Eq. JJ-3})$$

Where:

CH₄D = Methane flow to digester combustion device (metric tons CH₄/yr)

V_n = Daily average volumetric flow rate for day n, as determined from daily

monitoring as specified in § 98.364 (acfm).

C_n = Daily average CH₄ concentration of digester gas for day n, as determined from daily monitoring as specified in § 98.364 (% , wet basis)

0.0423 = Density of CH₄ lb/scf (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).

$$\text{CH}_4 \text{ Destruction at Digesters (kg/yr)} = \text{CH}_4 \text{D} \star \text{DE} \star \text{OH/Hours} \quad (\text{Eq. JJ-4})$$

Where:

CH₄D = Annual quantity of CH₄ flow to digester combustion device, as

calculated in Equation JJ-4 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).

OH = Number of hours combustion device is functioning in reporting year.

Hours = Hours in reporting year.

$$\text{CH}_4 \text{ Leakage at Digesters (kg/yr)} = \text{CH}_4 \text{D} \times \left(\frac{1}{\text{CE}} - 1 \right) \quad (\text{Eq. JJ-5})$$

CH₄D = Annual quantity of CH₄ combusted by digester, as calculated in Equation JJ-4 of this section (metric tons CH₄).

CE = CH₄ collection efficiency of anaerobic digester, as specified in Table JJ-3 of this section (decimal).

(c) For each manure management system type, estimate the annual N₂O emissions using Equation JJ-6 of this section.

$$\text{Direct N}_2\text{O Emissions (kg/yr)} = \sum_{\text{animal type}} \left[\sum_{\text{MMS}} \text{N}_{\text{ex}} \times \text{N}_{\text{ex,MMS}} \times \text{EF}_{\text{MMS}} \times 365.25 \text{ days/yr} \right] \times 44 \text{ N}_2\text{O} / 28 \text{ N}_2\text{O-N} \quad (\text{Eq. JJ-6})$$

Where:

N_{ex} = Total nitrogen excreted per animal type, calculated using Equation JJ-7 of this section (kg/day).

$N_{\text{ex,MMS}}$ = Percent of manure that is managed in each MMS (decimal) (assumed to be equivalent to the amount of N_{ex} in each system).

EF_{MMS} = Emission factor for MMS, as specified in Table JJ-4 of this section (kg N_2O-N /kg N).

$$N_{\text{ex}} = N_{\text{Manure}} \times (\text{Population} \times \text{TAM} \times \text{MER}/1000) \quad (\text{Eq. JJ-7})$$

Where:

N_{ex} = Total nitrogen excreted per animal type (kg/day).

N_{Manure} = Annual average percent of nitrogen present in manure by animal type, as determined from monthly manure

monitoring, as specified in § 98.364 (decimal).

Population = Average annual animal population (head).

TAM = Typical animal mass, using either default values in Table JJ-1 of this section or farm-specific data (kg/head).

MER = Manure excretion rate, using either default values in Table JJ-1 of this section or farm-specific data (kg manure/day/1,000 kg animal mass).

(d) Estimate the annual total annual emissions using Equation JJ-8 of this section.

$$\begin{aligned} \text{Total Emissions (metric tons } CO_2e/\text{yr)} = & [(\text{CH}_4 \text{ emissions} + \text{CH}_4 \text{ flow to digester combustion} \\ & \text{device} - \text{CH}_4 \text{ destruction of digester} + \text{CH}_4 \text{ leakage of digester}) \\ & \times 1 \text{ metric ton}/1000 \text{ kg} \times 21] + [\text{direct } N_2O \text{ emissions} \times 1 \text{ metric ton}/1000 \text{ kg} \times 310] \end{aligned} \quad (\text{Eq. JJ-8})$$

Where:

CH_4 emissions = From Equation JJ-1 of this section.

CH_4 flow to digester combustion device = From Equation JJ-3 of this section.

CH_4 destruction of digester = From Equation JJ-4 of this section.

CH_4 leakage of digester = From Equation JJ-5 of this section.

21 = Global Warming Potential of CH_4 .

Direct N_2O emissions = from Equation JJ-6 of this section.

310 = Global Warming Potential of N_2O .

§ 98.364 Monitoring and QA/QC requirements.

(a) Perform a one-time analysis on your operation to determine the percent of total manure by weight that is managed in each on-site manure management system.

(b) Determine the annual average percent total volatile solids by animal type, (%TVS) by analysis of a representative sample using Method 160.4 (Residue, Volatile) as described in Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79/020, Revised March 1983. The laboratory performing the analyses should be certified for analysis of waste for National Pollutant Discharge Elimination System compliance reporting. The sample analyzed should be a representative composite of freshly excreted manure from each animal type contributing to the manure management system. Total volatile solids of manure must be sampled and analyzed monthly.

(c) Determine the annual average percent of nitrogen present in manure by animal type (N_{Manure}) by analysis of a representative sample using Method 351.3 as described in Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020, Revised March 1983. The laboratory performing the

analyses should be certified for analysis of waste for National Pollutant Discharge Elimination System compliance reporting. The sample analyzed should be a representative composite of freshly excreted manure from each animal type contributing to the manure management system. Sample collection and analysis must be monthly.

(d) The flow and CH_4 concentration of gas from digesters must be determined using ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference in § 98.7).

(e) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(f) All gas flow meters and gas composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Gas flow meters and gas composition monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(g) All equipment (temperature and pressure monitors and gas flow meters and gas composition monitors) shall be

maintained as specified by the manufacturer.

(h) 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.

§ 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, volatile solids, or nitrogen or methane 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.

In addition to the information required by § 98.3(c), each annual report

must contain the following information for each manure management system component:

- (a) Type of manure management system component.
- (b) Animal population (by animal type).
- (c) Monthly total volatile solids content of excreted manure.
- (d) Percent of manure handled in each manure management system component.
- (e) B₀ value used.
- (f) Methane conversion factor used.
- (g) Average animal mass (for each type of animal).

- (h) Monthly nitrogen content of excreted manure.
- (i) N₂O emission factor selected.
- (j) CH₄ emissions
- (k) N₂O emissions.
- (l) Total annual volumetric biogas flow (for systems with digesters).
- (m) Average annual CH₄ concentration (for systems with digesters).
- (n) Temperature at which gas flow is measured (for systems with digesters).
- (o) Pressure at which gas flow is measured (for systems with digesters).
- (p) Destruction efficiency used (for systems with digesters).

- (q) Methane destruction (for systems with digesters).
- (r) Methane generation from the digesters.

§ 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.

§ 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—WASTE CHARACTERISTICS DATA

Animal group	Animal group typical animal mass (kg)	Manure excretion rate (kg/day/1000 kg animal mass)	Maximum methane generation potential, B ₀ (m ³ CH ₄ /kg VS added)
Dairy Cows	604	80.34	0.24
Dairy Heifers	476	85	0.17
Feedlot Steers	420	51.2	0.33
Feedlot Heifers	420	51.2	0.33
Market Swine <60 lbs.	16	106	0.48
Market Swine 60–119 lbs.	41	63.4	0.48
Market Swine 120–179 lbs.	68	63.4	0.48
Market Swine >180 lbs.	91	63.4	0.48
Breeding Swine	198	31.8	0.48
Feedlot Sheep	25	40	0.36
Goats	64	41	0.17
Horses	450	51	0.33
Hens >= 1 yr	1.8	60.5	0.39
Pullets	1.8	45.6	0.39
Other Chickens	1.8	60.5	0.39
Broilers	0.9	80	0.36
Turkeys	6.8	43.6	0.36

Table JJ-2 of Subpart JJ—Methane Conversion Factors

System	MCFs by 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
Aerobic Treatment	0.0%					0.0%										0.0%			
Cattle Deep Litter (<1 month)	3.0%					3.0%										30.0%			
Cattle Deep Litter (>1 month)	17%	19%	20%	22%	25%	27%	29%	33%	33%	33%	34%	34%	35%	35%	36%	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%			
Solid storage	2.0%					4.0%										5.0%			
Poultry manure with litter	1.5%					1.5%										1.5%			
Poultry manure without litter	1.5%					1.5%										1.5%			
Dry lot	1.0%					1.5%										2.0%			
System	<10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	>28
Pit storage <1 month	3.0%					3.0%										30.0%			
Pit storage >1 month	17%	19%	20%	22%	25%	27%	29%	33%	33%	33%	34%	34%	35%	35%	36%	65%	71%	78%	80%
Liquid/slurry (with crust cover)	10%	11%	13%	14%	15%	17%	18%	20%	22%	24%	26%	29%	31%	33%	33%	41%	44%	48%	50%
Liquid/slurry (w/o crust cover)	17%	19%	20%	22%	25%	27%	29%	33%	33%	33%	34%	34%	35%	35%	36%	65%	71%	78%	80%
Uncovered Anaerobic Lagoon	66%	68%	70%	71%	73%	74%	75%	77%	77%	77%	78%	78%	78%	79%	79%	79%	79%	80%	80%

TABLE JJ-3 OF SUBPART JJ—COLLECTION EFFICIENCIES OF ANAEROBIC DIGESTERS

System 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-4 OF SUBPART JJ—NITROUS OXIDE EMISSION FACTORS (kg N₂O-N/kg Kjdl N)

Waste management system	N ₂ O emission factor
Aerobic Treatment (forced aeration)	0.005
Aerobic Treatment (natural aeration)	0.01

TABLE JJ-4 OF SUBPART JJ—NITROUS OXIDE EMISSION FACTORS (kg N₂O-N/kg Kjdl N)—Continued

Waste management system	N ₂ O emission factor
Digester	0
Uncovered Anaerobic Lagoon	0
Cattle Deep Bed (active mix)	0.07
Cattle Deep Bed (no mix)	0.01

TABLE JJ-4 OF SUBPART JJ—NITROUS OXIDE EMISSION FACTORS (kg N₂O-N/kg Kjdl N)—Continued

Waste management system	N ₂ O emission factor
Manure Composting (in vessel)	0.006
Manure Composting (intensive)	0.1
Manure Composting (passive)	0.01
Manure Composting (static)	0.006

TABLE JJ-4 OF SUBPART JJ—NITROUS OXIDE EMISSION FACTORS (kg N₂O-N/kg Kjdl N)—Continued

Waste management system	N ₂ O emission factor
Deep Pit	0.002
Dry Lot	0.02
Liquid/Slurry	0.005
Poultry with bedding	0.001
Poultry without bedding	0.001
Solid Storage	0.005

Subpart KK—Supplies of Coal

§ 98.370 Definition of the source category.

(a) This source category comprises coal mines, coal importers, coal exporters, and waste coal reclaimers.
 (b) *Coal mine* means any active U.S. coal mine engaged in the production of coal within the U.S. during the calendar year regardless of the rank of coal produced, e.g., bituminous, sub-bituminous, lignite, anthracite. Any coal mine categorized as an active coal mine by MSHA is included.
 (c) Coal importer has the same meaning given in § 98.6 and includes

any U.S. coal mining company, wholesale coal dealer, retail coal dealer, or other organization that imports coal into the U.S. “Importer” includes the person primarily liable for the payment of any duties on the merchandise or an authorized agent acting on his or her behalf.

(d) Coal exporter has the same meaning given in § 98.6 and includes any U.S. coal mining company, wholesale coal dealer, retail coal dealer, or other organization that exports coal from the U.S.

(e) *Waste coal reclaimer* means any U.S. facility that reclaims or recovers waste coal from waste coal piles from previous mining operations and sells or delivers to an end-user.

§ 98.371 Reporting threshold.

Any supplier of coal who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.372 GHGs to report.

You must report the CO₂ emissions that would result from the complete

combustion or oxidation of coal supplied during the calendar year.

§ 98.373 Calculating GHG emissions.

(a) For coal mines producing 100,000 short tons of coal or more annually, the estimate of CO₂ emissions shall be calculated using either Calculation Methodology 1 or Calculation Methodology 2 of this subpart.

(b) For coal mines producing less than 100,000 short tons of coal annually, and for coal exporters, coal importers, and waste coal reclaimers; CO₂ emissions shall be calculated using either Calculation Methodology 1, 2, or 3 of this subpart.

(c) For Calculation Methodology 1, 2, and 3 of this subpart, emissions of CO₂ shall be calculated using Equation KK-1 of this section. The difference between Calculation Methodology 1, 2, and 3 of this subpart, is the method for determining the carbon content in coal, as specified in paragraphs (d), (e), and (f) of this section:

$$CO_2 = 44/12 * Mass * Carbon * 0.907 \quad (\text{Eq. KK-1})$$

Where:

CO₂ = Annual CO₂ mass emissions from the combustion of coal (metric tons/yr).
 44/12 = Ratio of molecular weights, CO₂ to carbon.
 Mass = Quantity of coal produced from company records (short tons/yr).

Carbon = Annual weighted average fraction of carbon in the coal (decimal value).
 0.907 = Conversion factor from short tons to metric tons.

(d) For coal mines using Calculation Methodology 1 of this subpart, the annual weighted average of the mass fraction of carbon in the coal shall be

$$Carbon = \sum_{i=1}^n (x_i * y_i) / S \quad (\text{Eq. KK-2})$$

Where:

Carbon = Annual mass fraction of coal carbon (dimensionless).
 Xi = Daily or per shipment mass fraction of carbon in coal for day i measured by ultimate analysis (decimal value).
 Yi = Amount of coal supplied on day i (short tons) as measured.
 n = Number of operating days per year.
 S = Total coal supplied during the year (short tons).

importers, exporters, and waste coal reclaimers using Calculation Methodology 2 of this subpart, measurements of each shipment can be used in place of daily measurements.

(1) Equation KK-3 shall be used to determine the weighted annual average GCV of the coal, and the individual daily or per shipment values shall be determined according to the monitoring methodology for gross calorific values in § 98.374(f).

(2) The statistical relationship between GCV and carbon content shall be established according to the requirements in § 98.374(f).

(3) The estimated annual weighted average of the mass fraction of carbon in the coal shall be calculated by applying the slope coefficient, determined

based on daily measurements and calculated using Equation KK-2 of this section. For importers, exporters, and waste coal reclaimers using Methodology 1 of this subpart, measurements of each shipment can be used in place of daily measurements:

according to the requirements of § 98.374(f)(4), to the weighted annual average GCV of the coal determined according to Equation KK-3 of this section.

(f) For coal mines using Calculation Methodology 3 of this subpart, the annual weighted average of the mass fraction of carbon in the coal shall be calculated on the basis of daily measurements of GCV of the coal and a default fraction of carbon in coal from Table KK-1 of this subpart. For importers, exporters, and waste coal reclaimers using Methodology 3 of this subpart, measurements of each shipment can be used in place of daily measurements.

(1) Equation KK-3 shall be used to determine the weighted annual average

(e) For coal mines using Calculation Methodology 2 of this subpart, the annual weighted average of the mass fraction of carbon in the coal shall be calculated on the basis of daily measurements of the gross calorific value (GCV) of the coal and a statistical relationship between carbon content and GCV (higher heating value). For

GCV of the coal, and the individual daily or per shipment values shall be determined according to the monitoring methodology for gross calorific values in § 98.374(g).

(2) The estimated annual weighted average of the mass fraction of carbon in the coal shall be identified from Table KK-1 of this subpart using annual weighted GCV of the coal determined according to Equation KK-3 of this section.

(g) For Calculation Methodologies 2 and 3 of this subpart, the weighted annual average gross calorific value (GCV) or higher heating value of the coal shall be calculated using Equation KK-3 of this section:

$$GCV = \sum_{i=1}^n (z_i * y_i) / S \quad (\text{Eq. KK-3})$$

Where:

GCV = the weighted annual average gross calorific value or higher heating value of the coal (Btu/lb).

z_i = Daily or per shipment GCV or HHV of coal for day i measured by proximate analysis (decimal value).

y_i = Amount of coal supplied on day i (short tons) as measured.

n = Number of operating days per year.

S = Total coal supplied during the year (short tons).

§ 98.374 Monitoring and QA/QC requirements.

(a) The most current version of the NIST Handbook published by Weights and Measures Division, National Institute of Standards and Technology shall be used as the standard practice for all coal weighing.

(b) For all coal mines, the quantity of coal shall be determined as the total mass of coal in short tons sold and removed from the facility during the calendar year.

(c) For coal importers, the quantity of coal shall be determined as the total mass of coal in short tons imported into the U.S. during the calendar year, as reported to U.S. Customs.

(d) For coal exporters, the quantity of coal shall be determined as the total mass of coal in short tons sold and exported from the U.S., as reported to U.S. Customs.

(e) For waste coal reclaimers, the quantity of coal shall be determined as the total mass of coal in short tons sold for use as reported to state agencies.

(f) For reporters using Calculation Methodology 1 of this subpart, the carbon content shall be determined as follows:

(1) Representative coal samples shall be collected daily or per shipment using ASTM D4916-04, D6609-07, D6883-04, D7256/D7256M-06a, or D7430-08 from coal loaded on the conveyor belt.

(2) Daily or per shipment coal carbon content shall be determined using ASTM D5373 (Test Methods for Instrumental Determination of Carbon Hydrogen and Nitrogen in Laboratory Samples of Coal and Coke).

(g) For reporters using Calculation Methodology 2 of this subpart, the carbon content shall be determined as follows:

(1) Representative samples of coal shall be collected daily or per shipment using ASTM D4916-04, D6609-07, D6883-04, D7256/D7256M-06a, or D7430-08.

(2) Coal gross calorific value (GCV) shall be determined on the set of samples collected in paragraph (f)(1) of this section using ASTM D5865-07a, "Standard Test Method for Gross Calorific Value of Coal and Coke to record the heat content of the coal produced.

(3) Coal carbon content shall be determined at a minimum once each month on one set of daily or per shipment samples collected in paragraph (f)(1) of this section using ASTM D5373 (Test Methods for Instrumental Determination of Carbon Hydrogen and Nitrogen in Laboratory Samples of Coal and Coke).

(4) The individual samples for which both carbon content and GCV were determined according to paragraphs (f)(2) and (f)(3) of this section respectively, shall be used to establish a statistical relationship between the heat content and the carbon content of the coal produced. The owner or operator shall statistically plot the correlation of Btu/lb of coal vs. percent carbon (as a decimal value), where the x-axis is Btu/lb coal and the y-axis is percent carbon (as decimal value), then fit a line to the data points, then calculate the slope and the coefficient of determination, and the R-square (R^2) of that line using the Btu/lb and percent carbon.

(5) Calculation Methodology 2 of this subpart can be used only if all of the following four conditions are met:

(i) At least 12 samples per reporting year from 12 different months of data must be used to construct the correlation graph.

(ii) The correlation graph must be constructed using all paired data points from the first reporting year and all subsequent reporting years.

(iii) There must be a linear relationship between percent carbon and Btu/lb of coal.

(iv) For the second and subsequent years, R-square (R^2) must be greater than or equal to 0.90. This R-square requirement does not apply during the first reporting year.

(6) If all of the conditions specified in paragraph (f)(5) of this section are met, the weighted annual average gross calorific value or higher heating value (Btu/lb) calculated according to Equation KK-3 of this section shall be used to determine the corresponding annual average coal carbon content using the correlation graph plotted according to paragraph (f)(4) of this section.

(h) Reporters complying with Calculation Methodology 3 of this subpart shall determine gross calorific value of the coal by collecting representative daily or per shipment samples of coal using either ASTM D4916-04, D6609-07, D6883-04, D7256/D7256M-06a, or D7430-08; and testing using ASTM D5865-07a, "Standard Test Method for Gross Calorific Value of Coal and Coke to record the heat content of the coal produced."

(i) Coal exporters shall calculate carbon content for each shipment of coal using information on the carbon content of the exported coal provided by the source mine, according to Calculation Methodology 1, 2, or 3 of this subpart, as appropriate.

(j) Coal importers shall calculate carbon content for each shipment of coal using Calculation Methodology 1, 2, or 3 of this subpart.

(k) Waste coal reclaimers shall calculate carbon content for each shipment of coal using Calculation Methodology 1, 2, or 3 of this subpart.

(l) Each owner or operator using mechanical coal sampling systems shall perform quality assurance and quality control according to ASTM D4702-07 and ASTM D6518-07.

§ 98.375 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.

(b) Whenever a quality-assured value for coal production during any time period is unavailable, you must use the average of the parameter values recorded immediately before and after the missing data period in the calculations.

(c) Facilities using Calculation Methodology 1 of this subpart shall develop the statistical relationship between GCV and carbon content according to § 98.274(e), and use this statistical relationship to estimate daily carbon content for any day for which

measured carbon content is not available.

(d) Facilities, importers and exporters using Calculation Methodology 2 or 3 of this subpart shall estimate the missing GCV values based on a weighted average value for the previous seven days.

(e) Estimates of missing data shall be documented and records maintained showing the calculations.

§ 98.376 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information:

(a) Each coal mine owner or operator shall report the following information for each coal mine:

(1) The name and MSHA ID number of the mine.

(2) The name of the operating company.

(3) Annual CO₂ emissions.

(4) By rank, the total annual quantity in tons of coal produced.

(5) The annual weighted carbon content of the coal as calculated according to § 98.373.

(6) If Calculation Methodology 1 of this subpart was used to determine CO₂ mass emissions, you must report daily mass fraction of carbon in coal measured by ultimate analysis and daily amount of coal supplied.

(7) If Calculation Methodology 2 of this subpart was used to determine CO₂ mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-squared (R²) value of the correlation.

(8) If Calculation Methodology 3 of this subpart was used to determine CO₂ mass emissions, you must report daily GCV of coal measured by proximate analysis and daily amount of coal supplied.

(b) Coal importers shall report the following information at the corporate level:

(1) The total annual quantity in tons of coal imported into the U.S. by the importer, by rank, and country of origin.

(2) Annual CO₂ emissions.

(3) The annual weighted carbon content of the coal as calculated according to § 98.373.

(4) If Calculation Methodology 1 of this subpart was used to determine CO₂ mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment.

(5) If Calculation Methodology 2 of this subpart was used to determine CO₂ mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-squared (R²) value of the correlation.

(6) If Calculation Methodology 3 of this subpart was used to determine CO₂ mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.

(d) Coal exporters shall report the following information at the corporate level:

(1) The total annual quantity in tons of coal exported from the U.S. by rank and by coal producing company and mine.

(2) Annual CO₂ emissions.

(3) The annual weighted carbon content of the coal as calculated according to § 98.373.

(4) If Calculation Methodology 1 of this subpart was used to determine CO₂ mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment.

(5) If Calculation Methodology 2 of this subpart was used to determine CO₂ mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-squared (R²) value of the correlation.

(6) If Calculation Methodology 3 of this subpart was used to determine CO₂ mass emissions, you must report GCV in coal per shipment measured by proximate analysis and amount of coal supplied per shipment.

(e) Waste coal reclaimers shall report the following information for each reclamation site:

(1) By rank, the total annual quantity in tons of waste coal produced.

(2) Mine and state of origin if waste coal is reclaimed from mines that are no longer operating.

(3) Annual CO₂ emissions.

(4) The annual weighted carbon content of the coal as calculated according to § 98.373.

(5) If Calculation Methodology 1 of this subpart was used to determine CO₂ mass emissions, you must report mass fraction of carbon in coal per shipment measured by ultimate analysis and amount of coal supplied per shipment.

(6) If Calculation Methodology 2 of this subpart was used to determine CO₂ mass emissions, you must report:

(i) All of the data used to construct the carbon vs. Btu/lb correlation graph.

(ii) Slope of the correlation line.

(iii) The R-square (R²) value of the correlation.

(7) If Calculation Methodology 3 of this subpart was used to determine CO₂ mass emissions, you must report GCV in

coal per shipment measured by proximate analysis and amount of coal supplied per shipment.

§ 98.377 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the following information:

(a) A complete record of all measured parameters used in the reporting of fuel quantities, including all sample results and documentation to support quantities that are reported under this part.

(b) Records documenting all calculations of missing data.

(c) Calculations and worksheets used to estimate the CO₂ emissions.

(d) Calibration records of any instruments used on site and calibration records of scales or other equipment used to weigh coal.

§ 98.378 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE KK-1 OF SUBPART KK—DE-FULT CARBON CONTENT OF COAL FOR METHOD 3 (CO₂ lbs/MMBtu¹)

Weighted annual average GCV of coal Btu/lb ¹	Mass fraction of carbon in coal (decimal)
2,000	0.1140
2,250	0.1283
2,500	0.1425
2,750	0.1568
3,000	0.1710
3,250	0.1853
3,500	0.1995
3,750	0.2138
4,000	0.2280
4,250	0.2423
4,500	0.2565
4,750	0.2708
5,000	0.2850
5,250	0.2993
5,500	0.3135
5,750	0.3278
6,000	0.3420
6,250	0.3563
6,500	0.3705
6,750	0.3848
7,000	0.3990
7,250	0.4133
7,500	0.4275
7,750	0.4418
8,000	0.4560
8,250	0.4703
8,500	0.4845
8,750	0.4988
9,000	0.5130
9,250	0.5273
9,500	0.5415
9,750	0.5558
10,000	0.5700
10,250	0.5843
10,500	0.5985
10,750	0.6128

TABLE KK-1 OF SUBPART KK—DEFAULT CARBON CONTENT OF COAL FOR METHOD 3 (CO₂ lbs/MMBtu¹)—Continued

Weighted annual average GCV of coal Btu/lb ¹	Mass fraction of carbon in coal (decimal)
11,000	0.6270
11,250	0.6413
11,500	0.6555
11,750	0.6698
12,000	0.6840
12,250	0.6983
12,500	0.7125
12,750	0.7268
13,000	0.7410
13,250	0.7553
13,500	0.7695
13,750	0.7838
14,000	0.7980
14,250	0.8123
14,500	0.8265
14,750	0.8408
15,000	0.8550

TABLE KK-1 OF SUBPART KK—DEFAULT CARBON CONTENT OF COAL FOR METHOD 3 (CO₂ lbs/MMBtu¹)—Continued

Weighted annual average GCV of coal Btu/lb ¹	Mass fraction of carbon in coal (decimal)
15,250	0.8693
15,500	0.8835

¹ Based on high heating values.

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 coal-based liquids.

(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

fuels such as gasoline and diesel using the Fischer-Tropsch process or an alternative process, involving conversion of coal into gas and then into liquids or conversion of coal directly into liquids (direct liquefaction).

(b) An importer or exporter shall have the same meaning given in § 98.6.

§ 98.381 Reporting threshold.

Any supplier of coal-based liquid fuels 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 coal-based liquids during the calendar year.

§ 98.383 Calculating GHG emissions.

(a) Coal-to-liquid producers, importers and exporters must calculate CO₂ emissions using Equation LL-1 of this section.

$$CO_2 = \sum (\text{Product}_i * EF_i) \quad (\text{Eq. LL-1})$$

Where:

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

Product_i = Total annual volume (in standard barrels) of a coal-based liquid fuel “i” produced, imported, or exported.

EF_i = CO₂ emission factor (metric tons CO₂ per barrel) specific to liquid fuel “i”.

(b) The emission factor (EF) for each type of coal-based liquid shall be determined using either of the

calculation methodologies described in paragraphs (a) and (b) of this section. The same calculation methodology must be used for the entire volume of the product for the reporting year.

(1) *Calculation Methodology 1.* Use the default CO₂ emission factor listed in column C of Table MM-1 of subpart MM (Suppliers of Petroleum Products) that most closely represents the coal-based liquid.

(2) *Calculation Methodology 2.*

Develop a CO₂ emission factor according to Equation LL-2 of this section using direct measurement of density and carbon share according to methods set forth in § 98.394(c) or a combination of direct measurement and the default factor listed in columns A or B of Table MM-1 of subpart MM that most closely represents the coal-based liquid.

$$EF = \text{Density} * \text{Wt\%} * (44/12) \quad (\text{Eq. LL-2})$$

Where:

EF = Emission factor of coal-based liquid (metric tons CO₂ per barrel).

Density = Density of coal-based liquid (metric tons per barrel).

Wt% = Percent of total mass that carbon represents in coal-based liquid.

§ 98.384 Monitoring and QA/QC requirements.

(a) Producers must measure the quantity of coal-based liquid fuels using procedures for flow meters as described in subpart MM of this part.

(b) Importers and exporters must determine the quantity of coal-based liquid fuels using sales contract information on the volume imported or exported during the reporting period.

(1) The quantity of coal-based liquid fuels must be measured using sales contract information.

(2) The minimum frequency of the measurement of quantities of coal-based liquid fuels shall be the number of sales contracts executed in the reporting period.

(c) All flow meters and product monitors shall be calibrated prior to use for reporting, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, NAESB, or others). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(d) Reporters shall take the following steps to ensure the quality and accuracy of the data reported under these rules:

(1) For all volumes of coal-based liquid fuels, reporters shall maintain

meter and such other records as are normally maintained in the course of business to document fuel flows.

(2) For all estimates of CO₂ mass emissions, reporters shall maintain calculations and worksheets used to calculate the emissions.

§ 98.385 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the reporting of fuel volumes and the calculations of CO₂ mass emissions is required. Therefore, whenever a quality-assured measurement of the quantity of coal-based liquid fuels is unavailable a substitute data value for the missing quantity measurement shall be calculated and used in the calculations.

(b) For coal-to-liquids facilities, the last quality assured reading shall be

used. If substantial variation in the flow rate is observed or if a quality assured measurement of quantity is unavailable for any other reason, the average of the last and the next quality assured reading shall be used to calculate a substitute measurement of quantity.

(c) Calculation of substitute data shall be documented and records maintained showing the calculations.

§ 98.386 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information:

(a) Producers shall report the following information for each facility:

(1) The total annual volume of each coal-based liquid supplied to the economy (in standard barrels).

(2) The total annual CO₂ emissions in metric tons associated with each coal-based liquid supplied to the economy, calculated according to § 98.383(a).

(b) Importers shall report the following information at the corporate level:

(1) The total annual volume of each imported coal-based liquid (in standard barrels).

(2) The total annual CO₂ emissions in metric tons associated with each imported coal-based liquid, calculated according to § 98.383(a).

(c) Exporters shall report the following information at the corporate level:

(1) The total annual volume of each exported coal-based liquid (in standard barrels).

(2) The total annual CO₂ emissions in metric tons associated with each exported coal-based liquid, calculated according to § 98.383(a).

§ 98.387 Records that must be retained.

Reporters shall retain copies of all reports submitted to EPA. Reporters shall maintain records to support volumes that are reported under this part, including records documenting any calculation of substitute measured data. Reporters shall also retain calculations and worksheets used to estimate the CO₂ equivalent of the volumes reported under this part. These records shall be retained for five (5) years similar to 40 CFR part 80 fuels compliance reporting program.

§ 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.

(a) A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(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 blender or refiner of refined or semi-refined petroleum products.

(d) Exporter has the same meaning given in § 98.6 and includes any blender or refiner of refined or semi-refined petroleum products.

§ 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.

You 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, if you are a refiner, you 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) Except as provided in paragraph (g) 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.

$$CO_{2i} = \text{Product}_i \star EF_i \quad (\text{Eq. MM-1})$$

Where:

CO_{2i} = Annual potential CO₂ emissions from the complete combustion or oxidation of each petroleum product or natural gas liquid “i” (metric tons).

Product_i = Total annual volume of 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 CO₂ emission factor (metric tons CO₂ per barrel).

(b) Except as provided in paragraph (g) of this section, any refiner shall calculate CO₂ emissions from each non-crude feedstock using Equation MM-2 of this section.

$$CO_{2j} = \text{Feedstock}_j \star EF_j \quad (\text{Eq. MM-2})$$

Where:

CO_{2j} = Annual potential CO₂ emissions from the complete combustion or oxidation of each non-crude feedstock “j” (metric tons).

Feedstock_j = Total annual volume of a petroleum product or natural gas liquid “j” that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels). Any waste feedstock (see definitions) that enters the refinery must also be included.

EF_j = Feedstock-specific CO₂ emission factor (metric tons CO₂ per barrel).

(c) Refiners shall calculate CO₂ emissions from all biomass co-processed with petroleum feedstocks using Equation MM-3 of this section.

$$CO_{2m} = \text{Biomass}_m \star EF_m \quad (\text{Eq. MM-3})$$

Where:

CO_{2m} = Annual potential CO₂ emissions from the complete combustion or oxidation of biomass “m” (metric tons).

Biomass_m = Total annual volume 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 (barrels).

EF_m = Biomass-specific CO₂ emission factor (metric tons CO₂ per barrel).

(d) Refiners shall calculate total 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} = Total annual potential CO_2 emissions 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 potential CO_2 emissions from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

CO_{2j} = Annual potential CO_2 emissions from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

CO_{2m} = Annual potential CO_2 emissions from the complete combustion or oxidation of biomass "m" (metric tons).

(e) Importers and exporters shall calculate total CO_2 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 potential CO_2 emissions from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

CO_{2x} = Total annual potential CO_2 emissions from the complete combustion or oxidation of all petroleum products and natural gas liquids.

(f) Except as provided in paragraph (g) of this section, the emission factor (EF) for each petroleum product and natural gas liquid shall be determined using

either of the calculation methodologies described in paragraphs (f)(1) or (f)(2) of this section. The same calculation methodology must be used for the entire volume of the product for the reporting year.

(1) *Calculation Methodology 1.* Use the appropriate default CO_2 emission factors listed in column C of Tables MM-1 and MM-2 of this subpart.

(2) *Calculation Methodology 2.* 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) or a combination of direct measurements and default factors listed in columns A and B of Tables MM-1 and MM-2 of this subpart.

$$EF = \text{Density} \star \text{Wt\%} \star (44/12) \quad (\text{Eq. MM-6})$$

Where:

EF = Emission factor of petroleum or natural gas product or non-crude feedstock (metric tons CO_2 per barrel).

Density = Density of petroleum product or natural gas liquid or non-crude feedstock (metric tons per barrel).

Wt% = Percent of total mass that carbon represents in petroleum product or natural gas liquid or non-crude feedstock.

44/12 = Conversion factor for carbon to carbon dioxide.

(g) In the event that some portion of a petroleum product or feedstock is biomass-based and was not derived by co-processing biomass and petroleum feedstocks together (i.e., the petroleum product or feedstock was produced by blending a petroleum-based product with a biomass-based product), the reporting party shall calculate emissions for the petroleum product or feedstock according to one of the methods in

paragraph (g)(1) or (2) of this section, as appropriate.

(1) A reporting party using Calculation Methodology 1 of this subpart to determine the emission factor of a petroleum product shall calculate the CO_2 emissions associated with that product using Equation MM-7 of this section in place of Equation MM-1 of this section.

$$CO_{2i} = \text{Product}_i \star EF_i \star \% \text{Vol}_i \quad (\text{Eq. MM-7})$$

Where:

CO_{2i} = Annual potential CO_2 emissions from the complete combustion or oxidation of petroleum product "i" (metric tons).

Product_i = Total annual volume of 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 CO_2 emission factor (metric tons CO_2 per barrel) from MM-1.

$\% \text{Vol}_i$ = Percent volume of product "i" that is petroleum-based.

(2) A refinery using Calculation Methodology 1 of this subpart to determine the emission factor of a non-crude petroleum feedstock shall calculate the CO_2 emissions associated with that feedstock using Equation MM-8 in place of Equation MM-2 of this section.

$$CO_{2j} = \text{Feedstock}_j \star EF_j \star \% \text{Vol}_j \quad (\text{Eq. MM-8})$$

Where:

CO_{2j} = Annual potential CO_2 emissions from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

Feedstock_j = Total annual volume of a 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 CO_2 emission factor (metric tons CO_2 per barrel).

$\% \text{Vol}_j$ = Percent volume of feedstock "j" that is petroleum-based.

(3) A reporter using Calculation Methodology 2 of this subpart to determine the emission factor of a petroleum product must calculate the CO_2 emissions associated with that product using Equation MM-9 of this section in place of Equation MM-1 of this section.

$$\text{CO}_{2i} = (\text{Product}_i \star \text{EF}_i) - (\text{Product}_i \star \text{EF}_m \star \% \text{Vol}_m) \quad (\text{Eq. MM-9})$$

Where:

CO_{2i} = Annual potential CO_2 emissions from the complete combustion or oxidation of product “i” (metric tons).

Product_i = Total annual volume of 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-3 that most closely represents the component of product “i” that is biomass-based.

$\% \text{Vol}_m$ = Percent volume of petroleum product “i” that is biomass-based.

(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-10 in place of Equation MM-2 of this section.

$$\text{CO}_{2j} = (\text{Feedstock}_j \star \text{EF}_j) - (\text{Feedstock}_j \star \text{EF}_m \star \% \text{Vol}_m) \quad (\text{Eq. MM-10})$$

Where:

CO_{2j} = Annual potential CO_2 emissions from the complete combustion or oxidation of non-crude feedstock “j” (metric tons).

Feedstock_j = Total annual volume of non-crude feedstock “j” that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels). Any waste feedstock (see definitions) that enters the refinery must also be included.

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM-3 of subpart MM that most closely represents the component of product “i” that is biomass-based.

$\% \text{Vol}_m$ = Percent volume of non-crude feedstock “j” that is biomass-based.

(h) Refiners shall use the most appropriate default CO_2 emission factor (EF_m) for biomass in Table MM-3 to calculate CO_2 emissions in paragraph (c) of this section.

§ 98.394 Monitoring and QA/QC requirements.

(a) The quantity of petroleum products, natural gas liquids, biomass, and all feedstocks shall be determined using either a flow meter or tank gauge, depending on the reporters existing equipment and preferences.

(1) For flow meters any one of the following test methods can be used to determine quantity:

(i) Ultra-sonic flow meter: *AGA Report No. 9 (2007)*

(ii) Turbine meters: American National Standards Institute, *ANSI/ASME MFC-4M-1986*

(iii) Orifice meters: American National Standards Institute, *ANSI/API 2530 (also called AGA-3) (1991)*

(iv) Coriolis meters: *ASME MFC-11 (2006)*

(2) For tank gauges any one of the following test methods can be used to determine quantity:

(i) API-2550: *Measurements and Calibration of Petroleum Storage Tanks (1965)*

(ii) API MPMS 2.2: *A Manual of Petroleum Measurement Standards (1995)*

(iii) API-653: *Tank Inspection, Repair, Alteration and Reconstruction, 3rd edition (2008)*

(b) All flow meters and tank gauges shall be calibrated prior to use for reporting, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, or NAESB). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Product flow meters and tank gauges shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(c) For Calculation Methodology 2 of this subpart, samples of each petroleum product and natural gas liquid shall be taken each month for the reporting year. The composite sample shall be tested at the end of the reporting year using ASTM D1298 (2003), ASTM D1657-02 (2007), ASTM D4052-96 (2002)el, ASTM D5002-99 (2005), or ASTM D5004-89 (2004)el for density, as appropriate, and ASTM D5291 (2005) or ASTM D6729-(2004)el for carbon share, as appropriate (see Technical Support Document). Reporters must sample seasonal gasoline each month of the season and then test the composite sample at the end of the season.

§ 98.395 Procedures for estimating missing data.

Whenever a metered or quality-assured value of the quantity of petroleum products, natural gas liquids, biomass, or feedstocks during any period is unavailable, a substitute data value for the missing quantity measurement shall be used in the calculations contained in § 98.393.

(a) For marine-imported and exported refined and semi-refined products, the reporting party shall attempt to reconcile any differences between ship and shore volume readings. If the

reporting party is unable to reconcile the readings, the higher of the two volume values shall be used for emission calculation purposes.

(b) For pipeline imported and exported refined and semi-refined products, the last valid volume reading based on the company’s established procedures for purposes of product tracking and billing shall be used. If the pipeline experiences substantial variations in flow rate, the average of the last valid volume reading and the next valid volume reading shall be used for emission calculation purposes.

(c) For petroleum refineries, the last valid volume reading based on the facility’s established procedures for purposes of product tracking and billing shall be used. If substantial variation in the flow rate is observed, the average of the last and the next valid volume reading shall be used for emission calculation purposes.

§ 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) CO_2 emissions in metric tons for each petroleum product and natural gas liquid (ex refinery gate), calculated according to § 98.393(a) or (g).

(2) CO_2 emissions in metric tons for each petroleum product or natural gas liquid that enters the refinery annually as a feedstock to be further refined or otherwise used on site, calculated according to § 98.393(b) or (g).

(3) CO_2 emissions in metric tons from each type of biomass feedstock co-processed with petroleum feedstocks, calculated according to § 98.393(c).

(4) The total sum of CO_2 emissions from all products, calculated according to § 98.393(d).

(5) The total volume of each petroleum product and natural gas liquid associated with the CO_2 emissions reported in paragraphs (a)(1)

and (2) of this section, separately, and the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product. If a determination cannot be made whether the material is a petroleum product or a natural gas liquid, it shall be reported as a petroleum product.

(6) The total volume of any biomass co-processed with a petroleum product associated with the CO₂ emissions reported in paragraph (a)(3) of this section.

(7) The measured density and/or mass carbon share for any petroleum product or natural gas liquid for which CO₂ emissions were calculated using Calculation Methodology 2 of this subpart, along with the selected method from § 98.394(c) and the calculated EF.

(8) The total volume of each distillate fuel oil product or feedstock reported in paragraph (a)(5) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.

(9) All of the following information for all crude oil feedstocks used at the refinery:

- (i) Batch volume (in standard barrels).
- (ii) API gravity of the batch.
- (iii) Sulfur content of the batch.
- (iv) Country of origin of the batch.

(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) CO₂ emissions in metric tons for each imported petroleum product and natural gas liquid, calculated according to § 98.393(a).

(2) Total sum of CO₂ emissions, calculated according to § 98.393(e).

(3) The total volume of each imported petroleum product and natural gas liquid associated with the CO₂ emissions reported in paragraph (b)(1)

of this section as well as the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product. If you cannot determine whether the material is a petroleum product or a natural gas liquid, you shall report it as a petroleum product.

(4) The measured density and/or mass carbon share for any imported petroleum product or natural gas liquid for which CO₂ emissions were calculated using Calculation Methodology 2 of this subpart, along with the selected method from § 98.394(c) and the calculated EF.

(5) The total volume of each distillate fuel oil product reported in paragraph (b)(1) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.

(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) CO₂ emissions in metric tons for each exported petroleum product and natural gas liquid, calculated according to § 98.393(a).

(2) Total sum of CO₂ emissions, calculated according to § 98.393(e).

(3) The total volume of each exported petroleum product and natural gas liquid associated with the CO₂ emissions reported in paragraph (c)(1) of this section as well as the volume of the biomass-based component of each petroleum product reported in this paragraph that was produced by blending a petroleum-based product with a biomass-based product. If you cannot determine whether the material is a petroleum product or a natural gas liquid, you shall report it as a petroleum product.

(4) The measured density and/or mass carbon share for any petroleum product

or natural gas liquid for which CO₂ emissions were calculated using Calculation Methodology 2 of this subpart, along with the selected method from § 98.394(c) and the calculated EF.

(5) The total volume of each distillate fuel oil product reported in paragraph (c)(1) of this section that contains less than 15 ppm sulfur content and is free from marker solvent yellow 124 and dye solvent red 164.

§ 98.397 Records that must be retained.

(a) Any reporter described in § 98.391 shall retain copies of all reports submitted to EPA under § 98.396. In addition, any reporter under this subpart 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 volumes that are reported under this part, including records documenting any estimations of missing metered data. For all volumes of petroleum products, natural gas liquids, biomass, and feedstocks, reporters shall maintain meter and other records normally maintained in the course of business to document product and feedstock flows.

(c) Reporters shall also retain laboratory reports, calculations and worksheets used to estimate the CO₂ emissions of the volumes reported under this part.

(d) Estimates of missing data shall be documented and records maintained showing the calculations.

(e) 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 CO₂ FACTORS FOR PETROLEUM PRODUCTS^{1, 2}

Refined and semi-refined petroleum products	Column A: density (metric tons/ bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO ₂ /bbl) [Column A * Column B/100 * 44/12]
Motor Gasoline³			
Conventional—Summer	0.12	86.96	0.38
Conventional—Winter	0.12	86.96	0.37
Reformulated—Summer	0.12	86.60	0.37
Reformulated—Winter	0.12	86.60	0.37
Finished Aviation Gasoline	0.11	85.00	0.35

TABLE MM-1 OF SUBPART MM—DEFAULT CO₂ FACTORS FOR PETROLEUM PRODUCTS^{1,2}—Continued

Refined and semi-refined petroleum products	Column A: density (metric tons/ bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO ₂ /bbl) [Column A * Column B/100 * 44/12]
Blendstocks			
RBOB	0.12	86.60	0.38
CBOB	0.12	85.60	0.37
Others	0.11	84.00	0.34
Oxygenates			
Methanol	0.13	37.50	0.17
GTBA	0.12	64.90	0.29
t-butanol	0.12	64.90	0.29
MTBE	0.12	68.20	0.29
ETBE	0.12	70.50	0.30
TAME	0.12	70.50	0.31
DIPE	0.12	70.60	0.30
Kerosene-Type Jet Fuel	0.13	86.30	0.41
Naptha-Type Jet Fuel	0.12	85.80	0.39
Kerosene	0.13	86.01	0.41
Distillate Fuel Oil			
Diesel No. 1	0.13	86.40	0.43
Diesel No. 2	0.13	86.34	0.43
Diesel No. 4	0.15	86.47	0.46
Fuel Oil No. 1	0.13	86.40	0.43
Fuel Oil No. 2	0.13	86.34	0.43
Fuel Oil No. 4	0.15	86.47	0.46
Residual Fuel Oil No. 5 (Navy Special)	0.14	85.81	0.43
Residual Fuel Oil No. 6 (a.k.a. Bunker C)	0.16	85.68	0.49
Petrochemical Feedstocks			
Naphthas (< 401 °F)	0.12	84.11	0.36
Other Oils (> 401 °F)	0.13	86.34	0.43
Special Naphthas	0.12	84.76	0.38
Lubricants	0.14	85.80	0.45
Waxes	0.13	85.29	0.40
Petroleum Coke	0.07	92.28	0.23
Asphalt and Road Oil	0.16	83.47	0.50
Still Gas	0.07	24.40	0.06
Ethane	0.06	80.00	0.17
Ethylene	0.09	85.71	0.28
Propane	0.08	81.80	0.24
Propylene	0.08	85.71	0.26
Butane	0.09	82.80	0.28
Butylene	0.11	85.71	0.35
Isobutane	0.09	82.80	0.27
Isobutylene	0.09	85.71	0.29
Pentanes Plus	0.11	83.70	0.32
Miscellaneous Products	0.14	85.49	0.43
Unfinished Oils	0.14	85.49	0.43
Naphthas	0.12	85.70	0.37
Kerosenes	0.13	85.80	0.41
Heavy Gas Oils	0.15	85.80	0.46
Residuum	0.16	85.70	0.51
Waste Feedstocks	0.14	85.70	0.45

¹ In the case of transportation fuels blended with some portion of biomass-based fuel, the carbon share in Table MM-1 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 CO₂ FACTORS FOR NATURAL GAS LIQUIDS

Natural gas liquids	Column A: density tonnes/barrel	Column B: carbon share (% of mass)	Column C: computed emission factor (tonnes CO ₂ / bbl) [Column A * Column B/100 * 44/12]
C2+	0.08	81.79	0.24
C4+	0.10	83.15	0.30
C5+	0.11	83.70	0.32
C6+	0.11	84.04	0.34

TABLE MM-3 OF SUBPART MM—DEFAULT CO₂ FACTORS FOR BIOMASS-BASED FUEL AND BIOMASS FEEDSTOCK

Biomass products and feedstock	Column A: emission factor (tonnes CO ₂ / bbl)
Ethanol (100%)	0.23
Biodiesel (100%, methyl ester)	0.40
Rendered Animal Fat	0.37
Vegetable Oil	0.41

Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

§ 98.400 Definition of the source category.

This supplier category consists of natural gas processing plants and local natural gas distribution companies.

(a) Natural Gas Processing Plants are installations designed to separate and recover natural gas liquids (NGLs) or other gases and liquids from a stream of produced natural gas through the processes of condensation, absorption, adsorption, refrigeration, or other methods and to control the quality of natural gas marketed. This does not include field gathering and boosting stations.

(b) Local Distribution Companies 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.

§ 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) Natural gas processing plants must report the CO₂ emissions that would result from the complete combustion or oxidation of the annual quantity of propane, butane, ethane, isobutane and bulk NGLs sold or delivered for use off site.

(b) Local distribution companies 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.

§ 98.403 Calculating GHG emissions.

(a) For each type of fuel or product reported under this part, calculate the estimated CO₂ equivalent emissions using either of Calculation Methodology 1 or 2 of this subpart:

(1) *Calculation Methodology 1.* Estimate CO₂ emissions using Equation NN-1. For Equation NN-1, use the default values for higher heating values and CO₂ emission factors in Table NN-1 to this subpart. Alternatively, reporter-specific higher heating values and CO₂ emission factors may be used, provided they are developed using methods outlined in § 98.404. For Equation NN-2 of this section, use 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.

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

Where:

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

Fuel = Total annual volume of fuel or product (volume per year, typically in Mcf for gaseous fuels and bbl for liquid fuels).

HHV = Higher heat value of the fuel supplied (MMBtu/Mcf or MMBtu/bbl).

EF = Fuel-specific CO₂ emission factor (kg CO₂/MMBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons (MT/kg).

(2) *Calculation Methodology 2.* Estimate CO₂ emissions using Equation NN-2.

$$CO_2 = Fuel \star EF \quad (\text{Eq. NN-2})$$

Where:

CO₂ = Annual CO₂ mass emissions from the combustion of fuel supplied (metric tons)

Fuel = Total annual volume of fuel or product supplied (bbl or Mcf per year)

EF = Fuel-specific CO₂ emission factor (MT CO₂/bbl, or MT CO₂/Mcf)

§ 98.404 Monitoring and QA/QC requirements.

(a) The quantity of natural gas liquids and natural gas must be determined

using any of the oil and gas flow meter test methods that are in common use in the industry and consistent with the Gas Processors Association Technical Manual and the American Gas Association Gas Measurement Committee reports.

(b) The minimum frequency of the measurements of quantities of natural gas liquids and natural gas shall be based on the industry standard practices for commercial operations. For natural gas liquids these are measurements taken at custody transfers summed to the annual reportable volume. For natural gas these are daily totals of continuous measurements, and summed to the annual reportable volume.

(c) All flow meters and product or fuel composition monitors shall be calibrated prior to the first reporting year, using a suitable method published by the American Gas Association Gas Measurement Committee reports on flow metering and heating value calculations and the Gas Processors Association standards on measurement and heating value. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(d) Reporter-specific emission factors or higher heating values shall be determined using industry standard practices such as the American Gas Association (AGA) Gas Measurement Committee Report on heating value and the Gas Processors Association (GPA) Technical Standards Manual for NGL heating value; and ASTM D-2597-94 and ASTM D-1945-03 for compositional analysis necessary for estimating CO₂ emission factors.

§ 98.405 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the reporting of fuel volumes and in the calculations of CO₂ mass emissions is required. Therefore, whenever a quality-assured value of the quantity of natural gas liquids or natural gas 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) For NGLs, natural gas processing plants 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 processing plant 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, natural gas processors may substitute estimates based on contract quantities required to be delivered under purchase or delivery contracts with other parties.

(c) Natural gas local distribution companies may substitute the metered quantities from the delivering pipelines for all deliveries into the distribution system. In cases where the pipeline metered delivery data are not available, local distribution companies may substitute their pipeline nominations and scheduled quantities for the period when metered values of actual deliveries are not available.

(d) Estimates of missing data shall be documented and records maintained showing the calculations of the values used for the missing data.

§ 98.406 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the annual report for each natural gas processing plant must contain the following information.

(1) The total annual quantity in barrels of NGLs produced for sale or delivery on behalf of others in the following categories: Propane, natural butane, ethane, and isobutane, and all other bulk NGLs as a single category.

(2) The total annual CO₂ mass emissions associated with the volumes in paragraph (a)(1) of this section and calculated in accordance with § 98.403.

(b) In addition to the information required by § 98.3(c), the annual report for each local distribution company must contain the following information.

(1) The total annual volume in Mcf of natural gas received by the local distribution company for redelivery to

end users on the local distribution company's distribution system.

(2) The total annual CO₂ mass emissions associated with the volumes in paragraph (b)(1) of this section and calculated in accordance with § 98.403.

(3) The total natural gas volumes received for redelivery to downstream gas transmission pipelines and other local distribution companies.

(4) The name and EPA and EIA identification code of each individual covered facility, and the name and EIA identification code of any other end-user for which the local gas distribution company delivered greater than or equal to 460,000 Mcf during the calendar year, and the total natural gas volumes actually delivered to each of these end-users.

(5) The annual volume in Mcf 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 and Instructions.

- (i) Residential consumers.
- (ii) Commercial consumers.
- (iii) Industrial consumers.
- (iv) Electricity generating facilities.

(6) The total annual CO₂ mass emissions associated with the volumes in paragraph (b)(5) of this section and calculated in accordance with § 98.403.

§ 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.

(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)(4).

(e) Records relating to measured Btu content or carbon content.

§ 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 CO ₂ emission factor (kg CO ₂ /MMBtu)
Natural Gas	1.027 MMBtu/Mcf	53.02
Propane	3.836 MMBtu/bbl	63.02
Butane	4.326 MMBtu/bbl	64.93

TABLE NN-1 OF SUBPART NN—DEFAULT FACTORS FOR CALCULATION METHODOLOGY 1 OF THIS SUBPART—Continued

Fuel	Default high heating value factor	Default CO ₂ emission factor (kg CO ₂ /MMBtu)
Ethane	3.082 MMBtu/bbl	59.58
Isobutane	3.974 MMBtu/bbl	65.08
Natural Gas Liquids	4.140 MMBtu/bbl	63.20

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	Mcf	0.054452
Propane	Barrel	0.241745
Butane	Barrel	0.280887
Ethane	Barrel	0.183626
Isobutane	Barrel	0.258628
Natural Gas Liquids	Barrel	0.261648

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 GHGs does not include the reuse or recycling of a fluorinated GHG or the generation of HFC-23 during the production of HCFC-22.

(c) To produce nitrous oxide means to produce nitrous oxide by thermally decomposing ammonium nitrate (NH₄NO₃). 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) The total mass of each fluorinated GHG or nitrous oxide produced

annually shall be estimated by using Equation OO-1 of this section:

$$P = \sum_{p=1}^n P_p \quad (\text{Eq. OO-1})$$

Where:

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) The total mass of each fluorinated GHG or nitrous oxide produced over the period “p” shall be estimated by using Equation OO-2 of this section:

$$P_p = O_p - U_p \quad (\text{Eq. OO-2})$$

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) The total mass of each fluorinated GHG or nitrous oxide transformed shall be estimated by using Equation OO-3 of this section:

$$T = F_T - R \quad (\text{Eq. OO-3})$$

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).

R = Mass of residual, unreacted fluorinated GHG or nitrous oxide that is permanently removed from the transformation process (metric tons).

(d) The total mass of each fluorinated GHG destroyed shall be estimated by using Equation OO-4 of this section:

$$D = F_D * DE \quad (\text{Eq. OO-4})$$

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 at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 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 at least daily (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(c) The mass of fluorinated GHGs or nitrous oxide fed into transformation processes shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density

measurements with an accuracy and precision of 0.2 percent of full scale or better.

(d) If unreacted fluorinated GHGs or nitrous oxide are permanently removed (recovered, destroyed, or emitted) from the transformation process, the mass removed shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the unreacted fluorinated GHG or nitrous oxide, the concentration of the unreacted fluorinated GHG or nitrous oxide shall be measured at least daily 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 fluorinated GHG or nitrous oxide permanently removed from the transformation process.

(e) The mass of fluorinated GHG or nitrous oxide sent to another facility for transformation shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 percent of full scale or better.

(f) The mass of fluorinated GHG sent to another facility for destruction shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 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 measured at least daily 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 fluorinated GHG sent to another facility for destruction.

(g) The mass of fluorinated GHGs fed into the destruction device shall be measured at least daily using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 0.2 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 measured at least daily 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 fluorinated GHG destroyed.

(h) For purposes of Equation OO-4, the destruction efficiency can initially 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. Fluorinated GHG production facilities that destroy fluorinated GHGs shall conduct annual measurements of mass flow and fluorinated GHG concentrations at the outlet of the thermal oxidizer in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6. Tests shall be conducted under conditions that are typical for the production process and destruction device at the facility. The sensitivity of the emissions tests shall be sufficient to detect emissions equal to 0.01 percent of the mass of fluorinated GHGs being fed into the destruction device. If the test indicates that the actual DE of the destruction device is lower than the previously determined DE, facilities shall either:

(1) Substitute the DE implied by the most recent emissions test for the previously determined DE in the calculations in § 98.413, or

(2) Perform more extensive performance testing of the DE of the oxidizer and use the DE determined by the more extensive testing in the calculations in § 98.413.

(i) In their estimates of the mass of fluorinated GHGs destroyed, designated representatives of 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.

(j) All flowmeters, weigh scales, and combinations of volumetric and density measurements that are used to measure or calculate quantities that are to be reported under this subpart shall be calibrated using suitable NIST-traceable standards and suitable methods published by a consensus standards organization (*e.g.*, ASTM, ASME, ASHRAE, or others). Alternatively,

calibration procedures specified by the flowmeter, scale, or load cell manufacturer may be used. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(k) All gas chromatographs that are used to measure or calculate quantities that are to be reported under this subpart shall be calibrated at least monthly through analysis of certified standards with known concentrations of the same chemical(s) in the same range(s) (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Test Method 205, 40 CFR Part 51, Appendix M may also be used.

§ 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 the following requirements:

(1) For each missing value of the mass produced, fed into the production process (for used material being reclaimed), fed into transformation processes, 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. 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.

(2) For each missing value of fluorinated GHG concentration, except the annual destruction device outlet concentration measurement specified in § 98.414(h), 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. There are no missing value allowances for the annual destruction device outlet concentration measurement. A re-test must be performed if the data from the annual destruction device outlet concentration measurement are determined to be unacceptable or not representative of typical operations.

(3) Notwithstanding paragraphs (a)(1) and (2) of this section, if the owner or operator has reason to believe that the methods specified in paragraphs (a)(1) and (2) of this section are likely to significantly under- or overestimate the value of the parameter during the period when data were missing, the designated representative of the fluorinated GHG production facility shall develop his or her best estimate of the parameter, documenting the methods used, the rationale behind them, and the reasons why the methods specified in paragraphs (a)(1) and (2) of this section would probably lead to a significant under- or overestimate of the parameter. EPA may reject the alternative estimate and replace it with an estimate based on the applicable method in paragraph (a)(1) or (2) if EPA does not agree with the rationale or method for the alternative estimate.

§ 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 at the facility level:

(1) Total mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility.

(2) Total mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility.

(3) Total mass in metric tons of each fluorinated GHG destroyed at that facility.

(4) Total mass in metric tons of any fluorinated GHG or nitrous oxide sent to another facility for transformation.

(5) Total mass in metric tons of any fluorinated GHG sent to another facility for destruction.

(6) Total mass in metric tons of each reactant fed into the production process.

(7) Total mass in metric tons of each non-GHG reactant and by-product permanently removed from the process.

(8) Mass of used product added back into the production process (e.g., for reclamation).

(9) 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.

(10) 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.

(11) 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. Where the missing data have been estimated pursuant to § 98.415(a)(3), the report shall explain the rationale for the methods used to estimate the missing data and why the methods specified in § 98.415(a)(1) and (2) would lead to a significant under- or overestimate of the parameters.

(b) A fluorinated GHG production facility that destroys fluorinated GHGs shall report the results of the annual fluorinated GHG concentration measurements at the outlet of the destruction device, including:

(1) Flow rate of fluorinated GHG being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of fluorinated GHG at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(4) Emission rate calculated from (b)(2) and (b)(3) in kg/hr.

(c) A fluorinated GHG production facility that destroys fluorinated GHGs shall submit a one-time report containing the following information:

(1) Destruction efficiency (DE) of each destruction unit.

(2) Test 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.

(d) A bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their imports at the corporate level, except for transshipments and heels. 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) 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.

(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 destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for destruction.

(e) A bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes their exports at the corporate level, except for 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) Quantity exported by chemical in metric tons of chemical.

(5) Commodity code of the fluorinated GHGs and nitrous oxide shipped.

(6) Date on which, and the port from which, fluorinated GHGs and nitrous oxide were exported from the United States or its territories.

(7) Country to which the fluorinated GHGs or nitrous oxide were exported.

§ 98.417 Records that must be retained.

(a) In addition to the data required by § 98.3(g), the designated representative of a fluorinated GHG production facility shall retain the following records:

(1) Dated records of the data used to estimate the data reported under § 98.416, and

(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 designated representative of a 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 (c).

(c) In addition to the data required by § 98.3(g), the designated representative of a 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 designated representative of a 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 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.

(3) Be recovered and destroyed.

§ 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) Production process units that capture a CO₂ stream for purposes of supplying CO₂ for commercial applications. Capture refers to the separation and removal of CO₂ from a manufacturing process; fuel combustion

source; or a waste, wastewater, or water treatment process.

(2) Facilities with CO₂ production wells.

(3) Importers or exporters of bulk CO₂.

(b) This source category does not include the following:

(1) Geologic sequestration (long term storage) of CO₂.

(2) Injection and subsequent production and/or processing of CO₂ for enhanced oil and gas recovery.

(3) Above ground storage of CO₂.

(4) Transportation or distribution of CO₂ via pipelines, vessels, motor carriers, or other means.

(5) Purification, compression, or processing of CO₂.

(6) CO₂ imported or exported in equipment.

§ 98.421 Reporting threshold.

Any supplier of CO₂ who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.422 GHGs to report.

You must report the mass of carbon dioxide captured from production process units, the mass of carbon dioxide extracted from carbon dioxide production wells, and the mass of carbon dioxide imported and exported regardless of the degree of impurities in the carbon dioxide stream.

§ 98.423 Calculating GHG emissions.

(a) Facilities with production process units must calculate quarterly the total mass of carbon dioxide in a carbon dioxide stream in metric tons captured, prior to any subsequent purification, processing, or compressing, based on multiplying the mass flow by the composition data, according to Equation PP-1 of this section. Mass flow and composition data measurements are made in accordance with § 98.424.

$$CO_2 = \sum_{p=1}^4 Q * C_{CO_2} \quad (\text{Eq. PP-1})$$

Where:

CO₂ = CO₂ mass emission (metric tons per year).

C_{CO₂} = Quarterly average CO₂ concentration in flow (wt. % CO₂).

Q = Quarterly mass flow rate (metric tons per quarter).

(b) CO₂ production well facilities must calculate quarterly the total mass of carbon dioxide in a carbon dioxide stream from wells in metric tons, prior to any subsequent purification, processing, or compressing, based on multiplying the mass flow by the composition data, according to Equation PP-1. Mass flow and composition data measurements are made in accordance with § 98.424.

(c) Importers or exporters of a carbon dioxide stream must calculate quarterly the total mass of carbon dioxide imported or exported in metric tons, based on multiplying the mass flow by the composition data, according to Equation PP-1. Mass flow and composition data measurements are made in accordance with § 98.424. The quantities of CO₂ imported or exported in equipment, such as fire extinguishers, need not be calculated or reported.

§ 98.424 Monitoring and QA/QC requirements.

(a) Facilities with production process units that capture a carbon dioxide stream must measure on a quarterly basis using a mass flow meter the mass flow of the CO₂ stream captured. If production process units do not have mass flow meters installed to measure the mass flow of the CO₂ stream captured, measurements shall be based on the mass flow of gas transferred off site using a mass flow meter. In either case, sampling also must be conducted on at least a quarterly basis to determine the composition of the captured or transferred CO₂ stream.

(b) Carbon dioxide production well facilities must measure on a quarterly basis the mass flow of the CO₂ stream extracted using a mass flow meter. If the CO₂ production wells do not have mass flow meters installed to measure the mass flow of the CO₂ stream extracted, measurements shall be based on mass flow of gas transferred off site using a mass flow meter. In either case, sampling must be conducted on at least a quarterly basis to determine the composition of the extracted or transferred carbon dioxide.

(c) Importers or exporters of bulk CO₂ must measure on a quarterly basis the mass flow of the CO₂ stream imported or exported using a mass flow meter and must conduct sampling on at least a quarterly basis to determine the composition of the imported or exported CO₂ stream. If the importer of a CO₂ stream does not have mass flow meters installed to measure the mass flow of gas imported, the measurements shall be based on the mass flow of the imported CO₂ stream transferred off site or used in on-site processes, as measured by mass flow meters. If an exporter of a CO₂ stream does not have mass flow meters installed to measure the mass flow exported, the measurements shall be based on the mass flow of the CO₂ stream received for export, as measured by mass flow meters. In all cases, sampling on at least a quarterly basis also must be conducted to determine the composition of the CO₂ stream.

(d) Mass flow meter calibrations must be NIST traceable.

(e) Methods to measure the composition of the carbon dioxide captured, extracted, transferred, imported, or exported must conform to applicable chemical analytical standards. Acceptable methods include U.S. Food and Drug Administration food-grade specifications for carbon dioxide (see 21 CFR 184.1250) and ASTM standard E-1745-95 (2005).

§ 98.425 Procedures for estimating missing data.

(a) Missing quarterly monitoring data on mass flow of CO₂ streams captured, extracted, imported, or exported shall be substituted with the greater of the following values:

(1) Quarterly CO₂ mass flow of gas transferred off site measured during the current reporting year.

(2) Quarterly or annual average values of the monitored CO₂ mass flow from the past calendar year.

(b) Missing monitoring data on the mass flow of the CO₂ stream transferred off site shall be substituted with the quarterly or annual average values from off site transfers from the past calendar year.

(c) Missing data on composition of the CO₂ stream captured, extracted, transferred, imported, or exported may be substituted for with quarterly or annual average values from the past calendar year.

§ 98.426 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information.

(a) Each facility with production process units or CO₂ production wells must report the following information:

(1) Total annual mass in metric tons and the weighted average composition of the CO₂ stream captured, extracted, or transferred in either gas, liquid, or solid forms.

(2) Annual quantities in metric tons transferred to the following end use applications by end-use, 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.
- (b) CO₂ importers and exporters must report the information in paragraphs (a)(1) and (a)(2) at the corporate level.

§ 98.427 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.

(a) The owner or operator of a facility containing production process units must retain quarterly records of captured and transferred CO₂ streams and composition.

(b) The owner or operator of a carbon dioxide production well facility must maintain quarterly records of the mass flow of the extracted and transferred CO₂ stream and composition.

(c) Importers or exporters of CO₂ must retain quarterly records of the mass flow and composition of CO₂ streams 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 600—[AMENDED]

27. The authority citation for part 600 continues to read as follows:

Authority: 49 U.S.C. 32901-23919q, Pub. L. 109-58.

Subpart A—[Amended]

28. Section 600.006-08 is amended by revising paragraph (c) introductory text and adding paragraph (c)(5) to read as follows:

§ 600.006-08 Data and information requirements for fuel economy vehicles.

* * * * *

(c) The manufacturer shall submit the following data:

* * * * *

(5) Starting with the 2011 model year, the data submitted according to paragraphs (c)(1) through (c)(4) of this section shall include CO₂, N₂O, and CH₄ in addition to fuel economy. Use the procedures specified in 40 CFR part 1065 as needed to measure N₂O and CH₄. Round the test results as follows:

- (i) Round CO₂ to the nearest 1 g/mi.
- (ii) Round N₂O to the nearest 0.001 g/mi.
- (iii) Round CH₄ to the nearest 0.001g/mi.

* * * * *

PART 1033—[AMENDED]

29. The authority citation for part 1033 continues to read as follows:

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

Subpart C—[Amended]

30. 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) Starting in the 2011 model year, report measured N₂O and CH₄ as described in § 1033.235. Small manufacturers/remanufacturers may omit this requirement.

* * * * *

31. Section 1033.235 is amended by adding paragraph (i) to read as follows:

§ 1033.235 Emission testing required for certification.

* * * * *

(i) Starting in the 2011 model year, measure N₂O, and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small manufacturers/remanufacturers may omit this requirement. 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/kW-hr.
- (2) Round N₂O to the nearest 0.001 g/kW-hr.
- (3) Round CH₄ to the nearest 0.001g/kW-hr.

Subpart J—[Amended]

32. 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]

33. The authority citation for part 1039 continues to read as follows:

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

Subpart C—[Amended]

34. 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) Starting in the 2011 model year, report measured CO₂, N₂O, and CH₄ as described in § 1039.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

35. 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) Starting in the 2011 model year, measure CO₂, N₂O, and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. 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 I—[Amended]

36. 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]

37. The authority citation for part 1042 continues to read as follows:

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

Subpart C—[Amended]

38. 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) Starting in the 2011 model year, report measured CO₂, N₂O, and CH₄ as described in § 1042.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

39. Section 1042.235 is amended by adding paragraph (g) to read as follows:

§ 1042.235 Emission testing required for a certificate of conformity.

* * * * *

(g) Starting in the 2011 model year, measure CO₂, N₂O, and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. 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 J—[Amended]

40. 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]

41. The authority citation for part 1045 continues to read as follows:

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

Subpart C—[Amended]

42. Section 1045.205 is amended by revising paragraph (q) to read as follows:

§ 1045.205 What must I include in my application?

* * * * *

(q) 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) Starting in the 2011 model year, report measured CO₂, N₂O, and CH₄ as described in § 1045.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

43. 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, N₂O, and CH₄ with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. 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.

PART 1048—[AMENDED]

44. The authority citation for part 1048 continues to read as follows:

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

Subpart C—[Amended]

45. 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) Starting in the 2011 model year, report measured CO2, N2O, and CH4 as described in § 1048.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

46. 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) Starting in the 2011 model year, measure CO2, N2O, and CH4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. 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 I—[Amended]

47. 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]

48. The authority citation for part 1051 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

49. 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) Starting in the 2011 model year, report measured CO2, N2O, and CH4 as described in § 1051.235. Small-volume manufacturers may omit this requirement.

* * * * *

50. 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) Starting in the 2011 model year, measure CO2, N2O, and CH4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume manufacturers may omit this requirement. 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 I—[Amended]

51. 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]

52. The authority citation for part 1054 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

53. 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) Starting in the 2011 model year, report measured CO2, N2O, and CH4 as described in § 1054.235. Small-volume engine manufacturers may omit this requirement.

* * * * *

54. 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, N2O, and CH4 with each low-hour certification test using the procedures specified in 40 CFR part 1065. Small-volume engine manufacturers may omit this requirement. 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 0.001 g/kW-hr.

55. A new part 1064 is added to subchapter U of chapter I to read as follows:

PART 1064—VEHICLE TESTING PROCEDURES

Subpart A—Applicability and general provisions

Sec. 1064.1 Applicability.

Subpart B—Air Conditioning Systems

1064.201 Method for calculating emissions due to air conditioning leakage.

Authority: 42 U.S.C. 7401–7671q.

Subpart A—Applicability and General Provisions

§ 1064.1 Applicability.

(a) This part describes procedures that apply to testing we require for 2011 and later model year light-duty vehicles, light-duty trucks, and medium-duty personal vehicles (see 40 CFR part 86).

(b) See 40 CFR part 86 for measurement procedures related to exhaust and evaporative emissions.

Subpart B—Air Conditioning Systems

§ 1064.201 Method for calculating emissions due to air conditioning leakage.

Determine a refrigerant leakage rate from vehicle-based air conditioning units as described in this section.

(a) *Emission totals.* Calculate an annual rate of refrigerant leakage from an air conditioning system using the following equation:

$$\text{Grams/YR}_{\text{TOT}} = \text{Grams/YR}_{\text{RP}} + \text{Grams/YR}_{\text{SP}} + \text{Grams/YR}_{\text{FH}} + \text{Grams/YR}_{\text{MC}} + \text{Grams/YR}_{\text{C}}$$

Where:

Grams/YR_{RP} = Emission rate for rigid pipe connections as described in paragraph (b) of this section.

Grams/YR_{SP} = Emission rate for service ports and refrigerant control devices as described in paragraph (c) of this section.

Grams/YR_{FH} = Emission rate for flexible hoses as described in paragraph (d) of this section.

Grams/YR_{MC} = Emission rate for heat exchangers, mufflers, receiver/driers, and accumulators as described in paragraph (e) of this section.

Grams/YR_C = Emission rate for compressors as described in paragraph (f) of this section.

(b) *Fittings.* Determine the emission rate for rigid pipe connections using the following Equation:

$$\text{Grams/YR}_{\text{RP}} = 0.00522 \cdot [(125 \cdot \text{SO}) + (75 \cdot \text{SCO}) + (50 \cdot \text{MO}) + (10 \cdot \text{SW}) + (5 \cdot \text{SWO}) + (\text{MG})]$$

Where:

SO = The number of single O-ring connections.

SCO = The number of single captured O-ring connections.

MO = The number of multiple O-ring connections.

SW = The number of seal washer connections.

SWO = The number of seal washer with O-ring connections.

MG = The number of metal gasket connections.

(c) *Service ports and refrigerant control devices.* Determine the emission rate for service ports and refrigerant control devices using the following Equation:

$$\text{Grams/YR}_{\text{SP}} = (0.3 \cdot \text{HSSP}) + (0.2 \cdot \text{LSSP}) + (0.2 \cdot \text{STV}) + (0.2 \cdot \text{TXV})$$

Where:

HSSP = The number of high side service ports.

LSSP = The number of low side service ports.

STV = The total number of switches, transducers, and expansion valves.

TXV = The number of TXV refrigerant control devices.

(d) *Flexible hoses.* Determine the permeation emission rate for each segment of flexible hose using the following Equation, then add those values to calculate a total emission rate for the system:

$$\text{Grams/YR}_{\text{FH}} = 0.00522 \cdot (3.14159 \cdot \text{ID} \cdot \text{L} \cdot \text{ER})$$

Where:

ID = Inner diameter of hose, in millimeters.

L = Length of hose, in millimeters.

ER = Emission rate per unit internal surface area of the hose, in g/mm². Select the appropriate value from the following table:

Material/configuration	ER	
	High-pressure side	Low-pressure side
Rubber	0.0216	0.0144
Standard barrier or veneer hose	0.0054	0.0036
Ultra-low permeation barrier or veneer hose	0.00225	0.00167

(e) *Heat exchangers, mufflers, receiver/driers, and accumulators.* Use an emission rate of 0.5 grams per year as a combined value for all heat exchangers, mufflers, receiver/driers, and accumulators (Grams/YR_{MC}).

(f) *Compressors.* Determine the emission rate for compressors using the following equation:

$$\text{Grams/YR}_{\text{C}} = 0.00522 \cdot [(300 \cdot \text{OHS}) + (200 \cdot \text{MHS}) + (150 \cdot \text{FAP}) + (100 \cdot \text{GHS}) + (1500/\text{SSL})]$$

Where:

OHS = The number of O-ring housing seals.

MHS = The number of molded housing seals.

FAP = The number of fitting adapter plates.

GHS = The number of gasket housing seals.

SSL = The number of lips on shaft seal (for belt-driven compressors only).

PART 1065—[AMENDED]

56. The authority citation for part 1065 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart C—[Amended]

57. A new § 1065.257 is added to subpart C to read as follows:

§ 1065.257 Nondispersive N₂O infrared analyzer.

(a) *Application.* Use a nondispersive infrared (NDIR) analyzer to measure N₂O concentrations in diluted exhaust for batch sampling. Batch sampling may be performed in a single bag covering all phases of the test procedure.

(b) *Component requirements.* We recommend that you use an NDIR analyzer that meets the specifications in Table 1 of § 1065.205. Note that your NDIR-based system must meet the calibration and verification in § 1065.357 and it must also meet the linearity verification in § 1065.307. 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.

(c) *Artifact formation, SO₂, and H₂O removal.* SO₂, NO_x, and H₂O have been shown to react in the sample bag to form N₂O. SO₂ and H₂O must therefore be sequentially removed from the sample gas before the sample enters the bag. SO₂ can be neutralized from the sample gas by passing the sample through a sorbent cartridge packed with 120 cc of a 10:1 ratio of 18–20 mesh sand and Ca(OH)₂. This sorbent works only in the presence of H₂O so the H₂O sorbent cartridge must be located downstream of the SO₂ sorbent cartridge. H₂O can be removed by passing the sample through a sorbent cartridge packed with 120 cc of P₂O₅.

58. A new § 1065.357 is added to subpart D to read as follows:

§ 1065.357 CO and Co₂ interference verification for N₂O NDIR analyzers.

(a) *Scope and frequency.* If you measure CO using an NDIR analyzer,

verify the amount of CO and CO₂ interference after initial analyzer installation and after major maintenance.

(b) *Measurement principles.* CO and CO₂ can positively interfere with an NDIR analyzer by causing a response similar to N₂O. If the NDIR 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.* A N₂O NDIR analyzer must have combined CO and CO₂ interference that is within ±2 percent of the flow-weighted mean concentration of N₂O expected at the standard, though we strongly recommend a lower interference that is within ±1 percent.

(d) *Procedure.* Perform the interference verification as follows:

(1) Start, operate, zero, and span the N₂O NDIR analyzer as you would before an emission test.

(2) Introduce a CO span to the analyzer.

(3) Allow time for the analyzer response to stabilize. Stabilization time may include time to purge the transfer

line and to account for analyzer response.

(4) While the analyzer measures the sample's concentration, record its output for 30 seconds. Calculate the arithmetic mean of this data.

(5) Scale the CO interference by multiplying this mean value (from paragraph (d)(7) of this section) by the ratio of expected CO to span gas CO concentration. In other words, estimate the flow-weighted mean dry concentration of CO expected during testing, and then divide this value by the concentration of CO in the span gas used for this verification. Then multiply this ratio by the mean value recorded during this verification (from paragraph (d)(7) of this section).

(6) Repeat the steps in paragraphs (d)(2) through (5) of this section, but with a CO₂ analytical gas mixture instead of CO and without humidifying the sample through the distilled water in a sealed vessel.

(7) Add together the CO and CO₂-scaled result of paragraphs (d)(5) and (6) of this section.

(8) The analyzer meets the interference verification if the result of paragraph (d)(7) of this section is within ±2 percent of the flow-weighted mean

concentration of N₂O expected at the standard.

(e) *Exceptions.* The following exceptions apply:

(1) You may omit this verification if you can show by engineering analysis that for your N₂O sampling system and your emission calculations procedures, the combined CO, CO₂, and H₂O interference for your N₂O NDIR analyzer always affects your brake-specific N₂O emission results within ±0.5 percent of the applicable N₂O standard.

(2) You may use a N₂O NDIR analyzer that you determine does not meet this verification, as long as you try to correct the problem and the measurement deficiency does not adversely affect your ability to show that engines comply with all applicable emission standards.

Subpart H—[Amended]

59. 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 µmol/mol	<0.05 µmol/mol
CO	<1 µmol/mol	<1 µmol/mol.
CO ₂	<10 µmol/mol	<10 µmol/mol.
O ₂	0.205 to 0.215 mol/mol	<2 µmol/mol.
NO _x	<0.02 µmol/mol	<0.02 µmol/mol.
N ₂ O	<0.05 µmol/mol	<0.05 µmol/mol.

¹ We do not require these levels of purity to be NIST-traceable.

* * * * *

(3) * * *

(xi) N₂O, balance purified N₂.

* * * * *

Subpart K—[Amended]

60. 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.

* * * * *

61. Section 1065.1005 is amended by adding items to the table in paragraph (b) in alphanumeric order to read as follows:

§ 1065.1005 Symbols, abbreviations, acronyms, and units of measure.

* * * * *

(b) * * *

Symbol	Species
Ca(OH)_2	calcium hydroxide
P_2O_5	phosphorous pentoxide
SO_2	sulfur dioxide

* * * * *

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