ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 98

[EPA–HQ–OAR–2019–0424; FRL–7230–01–OAR]

RIN 2060–AU35

Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is amending specific provisions in the Greenhouse Gas Reporting Rule to improve data quality and consistency. This action updates the General Provisions to reflect revised global warming potentials; expands reporting to additional sectors; improves the calculation, recordkeeping, and reporting requirements by updating existing methodologies; improves data verifications; and provides for collection of additional data to better inform and be relevant to a wide variety of Clean Air Act provisions that the EPA carries out. This action adds greenhouse gas monitoring and reporting for five source categories including coke calcining; ceramics manufacturing; calcium carbide production; caprolactam, glyoxal, and glyoxylic acid production; and facilities conducting geologic sequestration of carbon dioxide with enhanced oil recovery. These revisions also include changes that will improve implementation of the rule such as updates to applicability estimation methodologies, simplifying calculation and monitoring methodologies, streamlining recordkeeping and reporting, and other minor technical corrections or clarifications. This action also establishes and amends confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these amendments.

DATES: This rule is effective January 1, 2025. The incorporation by reference of certain material listed in this final rule is approved by the Director of the Federal Register beginning January 1, 2025. The incorporation by reference of certain other material listed in the rule was approved by the Director of the Federal Register as of January 1, 2018.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2019–0424. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Jennifer Bohman, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW, Washington, DC 20460; telephone number: (202) 343–9548; email address: *GHGReporting@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Program (GHGRP) website, *www.epa.gov/ghgreporting.* To submit a question, select Help Center, followed by ''Contact Us.''

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule will also be available through the WWW. Following the Administrator's signature, a copy of this final rule will be posted on the EPA's GHGRP website at *www.epa.gov/ghgreporting.*

SUPPLEMENTARY INFORMATION:

Regulated entities. These final revisions affect certain entities that must submit annual greenhouse gas (GHG) reports under the GHGRP (codified at 40 CFR part 98). These are amendments to existing regulations and will affect owners or operators of certain industry sectors that are suppliers and direct emitters of GHGs. Regulated categories and entities include, but are not limited to, those listed in table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	North American Industry Classification System (NAICS)	Examples of facilities that may be subject to part 98:+
General Stationary Fuel Combustion Sources		Facilities operating boilers, process heaters, incinerators, turbines, and internal combustion engines.
	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.
Electric Power Generation	2211	Generation facilities that produce electric energy.
Adipic Acid Production	325199	All other basic organic chemical manufacturing: Adipic acid manufacturing.
Aluminum Production	331313	Primary aluminum production facilities.
Ammonia Manufacturing	325311	Anhydrous ammonia manufacturing facilities.
Calcium Carbide Production	325180	Other basic inorganic chemical manufacturing: calcium carbide manufacturing.

Table 1—Examples of Affected Entities by Category—Continued

Category	North American Industry Classification System (NAICS)	Examples of facilities that may be subject to part 98:+
Carbon Dioxide Enhanced Oil Recovery Projects	211120	Oil and gas extraction projects using carbon dioxide enhanced oil recovery.
Caprolactam, Glyoxal, and Glyoxylic Acid Production	325199	All other basic organic chemical manufacturing.
Cement Production	327310	Cement manufacturing.
Ceramics Manufacturing	327110	Pottery, ceramics, and plumbing fixture manufacturing.
	327120	Clay building material and refractories manufacturing.
Coke Calcining	299901	Coke; coke, petroleum; coke, calcined petroleum.
Electronics Manufacturing	334111	Microcomputers manufacturing facilities.
	334413	Semiconductor, photovoltaic (PV) (solid-state) device manufacturing facilities.
	334419	Liquid crystal display (LCD) unit screens manufacturing facilities; Microelectromechanical (MEMS) manufacturing facilities.
Electrical Equipment Manufacture or Refurbishment	33531	Power transmission and distribution switchgear and specialty transformers manufacturing facilities.
Electricity generation units that report through 40 CFR part 75.	221112	Electric power generation, fossil fuel (*e.g.,* coal, oil, gas).
Electrical Equipment Use	221121	Electric bulk power transmission and control facilities.
Electrical transmission and distribution equipment manufacture or refurbishment.	33361	Engine, Turbine, and Power Transmission Equipment Manufacturing.
Ferroalloy Production	331110	Ferroalloys manufacturing.
Fluorinated Greenhouse Gas Production	325120	Industrial gases manufacturing facilities.
Geologic Sequestration	NA	CO_2 geologic sequestration sites.
Glass Production	327211	Flat glass manufacturing facilities.
	327213	Glass container manufacturing facilities.
	327212	Other pressed and blown glass and glassware manufacturing facilities.
HCFC–22 Production	325120	Industrial gas manufacturing: Hydrochlorofluorocarbon (HCFC) gases manufacturing.
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.	325120	Industrial gas manufacturing: Hydrofluorocarbon (HFC) gases manufacturing.
Hydrogen Production	325120	Hydrogen manufacturing facilities.
Industrial Waste Landfill	562212	Solid waste landfills.
Industrial Wastewater Treatment	221310	Water treatment plants.
Injection of Carbon Dioxide	211	Oil and gas extraction.
Iron and Steel Production	333110	Integrated iron and steel mills, steel companies, sinter plants, blast furnaces, basic oxygen process furnace (BOPF) shops.
Lead Production	331	Primary metal manufacturing.
Lime Manufacturing	327410	Lime production.
Magnesium Production	331410	Nonferrous metal (except aluminum) smelting and refining: Magnesium refining, primary.
Nitric Acid Production	325311	Nitrogenous fertilizer manufacturing: Nitric acid manufacturing.
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211120	Crude petroleum extraction.
	211130	Natural gas extraction.
Petrochemical Production	324110	Petrochemicals made in petroleum refineries.
Petroleum Refineries	324110	Petroleum refineries.
Phosphoric Acid Production	325312	Phosphatic fertilizer manufacturing.
Pulp and Paper Manufacturing	322110	Pulp mills.
	322120	Paper mills.
	322130	Paperboard mills.
Miscellaneous Uses of Carbonate	Facilities included elsewhere.	
Municipal Solid Waste Landfills	562212	Solid waste landfills.
	221320	Sewage treatment facilities.
Silicon Carbide Production	327910	Silicon carbide abrasives manufacturing.
Soda Ash Production	325180	Other basic inorganic chemical manufacturing: Soda ash manufacturing.
Suppliers of Carbon Dioxide	325120	Industrial gas manufacturing facilities.
Suppliers of Industrial Greenhouse Gases	325120	Industrial greenhouse gas manufacturing facilities.
Titanium Dioxide Production	325180	Other basic inorganic chemical manufacturing: Titanium dioxide manufacturing.
Underground Coal Mines	212115	Underground coal mining.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	North American Industry Classification System (NAICS)	Examples of facilities that may be subject to part 98:+
Zinc Production	331410	Nonferrous metal (except aluminum) smelting and refining: Zinc refining, primary.
Suppliers of Coal-based Liquid Fuels	211130	Coal liquefaction at mine sites.
Suppliers of Natural Gas and Natural Gas Liquids	221210	Natural gas distribution facilities.
	211112	Natural gas liquid extraction facilities.
Suppliers of Petroleum Products	324110	Petroleum refineries.
Suppliers of Carbon Dioxide	325120	Industrial gas manufacturing facilities.
Suppliers of Industrial Greenhouse Gases	325120	Industrial greenhouse gas manufacturing facilities.
Importers and Exporters of Pre-charged Equipment and Closed-Cell Foams.	423730	Air-conditioning equipment (except room units) merchant wholesalers.
	333415	Air-conditioning equipment (except motor vehicle) manufacturing.
	423620	Air-conditioners, room, merchant wholesalers.
	449210	Electronics and appliance retailers.
	326150	Polyurethane foam products manufacturing.
	335313	Circuit breakers, power, manufacturing.
	423610	Circuit breakers and related equipment merchant wholesalers.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. This table lists the types of facilities that the EPA is now aware could potentially be affected by this action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you will be affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A (General Provisions) and each source category. Many facilities that are affected by 40 CFR part 98 have greenhouse gas emissions from multiple source categories listed in table 1 of this preamble. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Acronyms and abbreviations. The following acronyms and abbreviations are used in this document.

ACE	Automated Commercial Environment
AIM	American Innovation and Manufacturing Act of 2020
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	ASTM, International
BAMM	best available monitoring methods
BCFCs	bromochlorofluorocarbons
BEF	byproduct emission factor
BFCs	bromofluorocarbons
CAA	Clean Air Act
CaO	calcium oxide (lime)
CARB	California Air Resources Board
CAS	Chemical Abstracts Service
CBI	confidential business information
CBP	U.S. Customs and Border Protection
CCS	carbon capture and sequestration
CECS	combustion emissions control system
CEMS	continuous emissions monitoring system
CFC	chlorofluorocarbon
CFR	Code of Federal Regulations
CF_4	perfluoromethane
CGA	cylinder gas audit
CHP	combined heat and power
CH_4	methane
CKD	cement kiln dust
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COF_2	carbonic difluoride
CRA	Congressional Review Act
CSA	CSA Group
DAC	direct air capture
DCU	delayed coking unit
DOC	degradable organic carbon
DOE	U.S. Department of Energy
DRE	destruction or removal efficiency
EAF	electric arc furnace
EDC	ethylene dichloride
EF	emission factor
EGU	electricity generating unit
e-GGRT	electronic Greenhouse Gas Reporting Tool
EG	emission guidelines
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EREF	Environmental Research and Education Foundation
F–GHG	fluorinated greenhouse gas
F–HTF	fluorinated heat transfer fluids
FLIGHT	Facility Level Information on Greenhouse Gases Tool
FR	Federal Register
FTIR	Fourier Transform Infrared
GCCS	gas collection and capture system
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GIE	gas-insulated equipment
GWP	global warming potential
HBCFC	hydrobromochlorofluorocarbon
HBFC	hydrobromofluorocarbon
HC	hydrocarbon
HCFC	hydrochlorofluorocarbon
HCFE	hydrochlorofluoroether
HFC	hydrofluorocarbon
HFE	hydrofluoroether
HHV	high heating value
HTF	heat transfer fluid
HTS	Harmonized Tariff System
ICR	Information Collection Request
IPCC	Intergovernmental Panel on Climate Change
ISO	International Standards Organization
IVT	Inputs Verification Tool
k	first order decay rate
kg	kilogram
kV	kilovolt
LCD	liquid crystal display
LDC	local distribution company
LMOP	Landfill Methane Outreach Program
MEMS	Microelectromechanical systems
MgO	magnesium oxide
mmBtu	million British thermal units
MRV	monitoring, reporting, and verification plan
MW	molecular weight
MSW	municipal solid waste
mt	metric tons
$mtCO_2e$	metric tons carbon dioxide equivalent
MTBS	Mean Time Between Service
NAICS	North American Industry Classification System
NIST	National Institute of Standards and Technology
NSPS	new source performance standards
N_2O	nitrous oxide
OAR	Office of Air and Radiation
OMB	Office of Management and Budget
OMP	operations management plan
PFC	perfluorocarbon
POU	point of use
POX	partial oxidation
ppmv	parts per million volume
PRA	Paperwork Reduction Act
PSA	pressure swing absorption
psi	pounds per square inch
psia	pounds per square inch, absolute
PV	photovoltaic
QA/QC	quality assurance/quality control

RFA	Regulatory Flexibility Act
RPC	remote plasma cleaning
RY	reporting year
scf	standard cubic feet
SEM	surface-emissions monitoring
SF_6	sulfur hexafluoride
SMR	steam methane reforming
SSM	startup, shutdown, and malfunction
TSD	technical support document
UMRA	Unfunded Mandates Reform Act of 1995
UNFCCC	United Nations Framework Convention on Climate Change
U.S.	United States
VCM	vinyl chloride monomer
WGS	water gas shift
WMO	World Meteorological Organization
WWW	World Wide Web

Table of Contents

I. Background

A. How is this preamble organized?

Section I. of this preamble contains background information on the June 21, 2022 proposed rule (87 FR 36920, hereafter referred to as ''2022 Data Quality Improvements Proposal'') and the May 22, 2023 supplemental proposed rule (88 FR 32852, hereafter referred to as ''2023 Supplemental Proposal''). This section also discusses the EPA's legal authority under the CAA to promulgate (including subsequent amendments to) the GHG Reporting Rule, codified at 40 CFR part 98 (hereinafter referred to as ''part 98''), and the EPA's legal authority to make confidentiality determinations for new or revised data elements corresponding to these amendments or for existing data elements for which the EPA is finalizing a new determination. Section II. of this preamble describes the types of amendments included in this final rule. Section III. of this preamble is organized by part 98 subpart and contains detailed information on the final new requirements for, or revisions to, each subpart. Section IV. of this preamble describes the final revisions to 40 CFR part 9. Section V. of this preamble explains the effective date of the final revisions and how the revisions are required to be implemented in reporting year (RY) 2024 and RY2025 reports. Section VI. of this preamble discusses the final confidentiality determinations for new or substantially revised (*i.e.,* requiring additional or different data to be reported) data reporting elements, as well as for certain existing data elements for which the EPA is finalizing a new determination. Section VII. of this preamble discusses the impacts of the final amendments. Finally, section VIII. of this preamble describes the statutory and Executive order requirements applicable to this action.

B. Executive Summary

The EPA is finalizing certain proposed revisions to part 98 included in the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal, with some changes made after consideration of public comments. The final amendments include improvements to requirements that, broadly, will enhance the quality and the scope of information collected, clarify elements of the rule, and streamline elements of reporting and recordkeeping. These final revisions include a comprehensive update to the global warming potentials (GWPs) in table A–1 to subpart A of part 98; updates to provide for collection of additional data to understand new source categories or new emission sources for specific sectors; updates to emission factors to more accurately reflect industry emissions; refinements to existing emissions calculation methodologies to reflect an improved understanding of emissions sources and end uses of GHGs; additions or modifications to reporting requirements in order to eliminate data gaps and improve verification of reported emissions; revisions that address prior commenter concerns or clarify requirements; and editorial corrections that are intended to improve the public's understanding of the rule. The final amendments also include streamlining measures such as revisions to applicability for certain industry sectors to account for changes in usage of certain GHGs or instances where the current applicability estimation methodology may overestimate emissions; revisions that provide flexibility for or simplify monitoring and calculation methods; and revisions to streamline reported data elements or recordkeeping where the current requirements are redundant, where reported data are not currently useful for verification or analysis, or for which continued collection of the data at the same frequency would not likely provide new insights or knowledge of the industry sector, emissions, or trends at this time. This action also finalizes confidentiality determinations for the reporting of data elements added or substantially revised in these final amendments, and for certain existing data elements for which no confidentiality determination has been made previously or for which the EPA proposed to revise the existing determination.

In some cases, and as further described in section III. of this preamble, the EPA is not taking final action in this final rule on certain proposed revisions included in the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal. For example, after review of comments received in response to the proposed requirements to report purchased electricity and thermal energy consumption information under the proposed subpart B (Energy Consumption), the EPA is not taking action at this time on those proposed provisions. The EPA believes additional time is needed to consider the comments received before taking final action. Similarly, the EPA is not taking final action at this time on certain proposed changes for some subparts. In some cases, *e.g.,* for subparts G (Ammonia Production), P (Hydrogen Production), S (Lime Production), and HH (Municipal Solid Waste Landfills), we are not taking final action at this time on certain revisions to the calculation or monitoring methodologies that would have revised how data are collected and reported in the EPA's electronic greenhouse gas reporting tool (e-GGRT). In several cases, we are also not taking final action at this time on proposed revisions to add reporting requirements. For example, under subpart C (General Stationary Fuel Combustion), we are not taking final action at this time on proposed revisions to the requirements for units in either an aggregation of units or common pipe configuration that would have required reporters to provide additional information such as the unit type, maximum rated heat input capacity, and fraction of the actual total heat input for each unit in the aggregation or the common pipe configuration. Also under subpart C, we are not taking final action at this time on proposed requirements that would have required reporters to identify, for any configuration, whether the unit is an electricity generating unit, and, for group configurations (*i.e.,* common stack/duct, common pipe, and aggregation of units) that contain an electricity generating unit, the estimated decimal fraction of total emissions attributable to the electricity generating unit. Similarly, we are not taking final action at this time on certain data elements that were proposed to be added to subparts A (General Provisions), F (Aluminum Production), G, H (Cement Production), P, S, HH, OO (Suppliers of Industrial Greenhouse Gases), and QQ (Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment and Closed-Cell Foams). Additional proposed revisions that EPA is not taking final action on at this time are discussed in section III. of this preamble.

This final rule also includes an amendment to 40 CFR part 9 to include the Office of Management and Budget (OMB) control number issued under the Paperwork Reduction Act (PRA) for the information collection request for the GHGRP.

The final amendments will become effective on January 1, 2025. As provided under the existing regulations in subpart A of part 98, the GWP amendments to table A–1 to subpart A will apply to reports submitted by current reporters that are submitted in calendar year 2025 and subsequent years (*i.e.,* starting with reports submitted for RY2024 on March 31, 2025). All other final revisions, which apply to both existing and new reporters, will be implemented for reports prepared for RY2025 and submitted March 31, 2026. Reporters who are newly subject to the rule will be required to implement all requirements to collect data, including any required monitoring and recordkeeping, on January 1, 2025.

These final amendments are anticipated to result in an overall increase in burden for part 98 reporters in cases where the amendments expand current applicability, add or revise reporting requirements, or require additional emissions data to be reported. The primary burden associated with the final rule is due to revisions to applicability, including revisions to the global warming potentials in table A–1 to subpart A of part 98, that will change the number of reporters currently at or near the 25,000 metric tons carbon dioxide equivalent (mtCO$_2$e) threshold; revisions to establish requirements for new source categories for coke calcining, calcium carbide, caprolactam, glyoxal, and glyoxylic acid production, ceramics manufacturing, and facilities conducting geologic sequestration of carbon dioxide with enhanced oil recovery; and revisions to expand reporting to include new emission sources for specific sectors, such as the addition of captive (non-merchant) hydrogen production facilities. The final revisions will affect approximately 254 new reporters across 13 source categories, including the hydrogen production, petroleum and natural gas systems, petroleum refineries, electrical transmission and distribution systems, industrial wastewater treatment, municipal solid waste landfills, fluorinated GHG suppliers, and industrial waste landfills source categories, as well as the new source categories added in these final revisions. The EPA anticipates some decrease in burden where the final revisions will adjust or improve the estimation methodologies for determining applicability, simplify calculation methodologies or monitoring requirements, or simplify the data that must be reported. In several cases, we are also finalizing changes where we anticipate increased clarity or more flexibility for reporters that could result in a potential decrease in burden. The incremental implementation labor costs for all subparts include $2,684,681 in RY2025, and $2,671,831 in each subsequent year (RY2026 and RY2027). The incremental implementation labor costs over the next three years (RY2025 through RY2027) total $8,028,343. There is an additional incremental burden of $2,733,937 for capital and operation and maintenance (O&M) costs in RY2025 and in each subsequent year (RY2026 and RY2027), which reflects changes to applicability and monitoring for subparts with new or additional reporters. The incremental non-labor costs for RY2025 through RY2027 total $8,201,812 over the next three years.

C. Background on This Final Rule

The GHGRP requires annual reporting of GHG data and other relevant information from large facilities and suppliers in the United States. In its 2022 Data Quality Improvements Proposal, the EPA proposed amendments to specific provisions of part 98 where we identified opportunities to improve the quality of the data collected under the rule. This included revisions that would provide for the collection of additional data that may be necessary to better understand emissions from specific sectors or inform future policy decisions under the CAA; update emission factors; and refine emissions estimation methodologies. The proposed rule also included revisions that provided for the collection of additional data that would be useful to improve verification of collected data and complement or inform other EPA programs. These proposed revisions included the incorporation of a new source category to add calculation and reporting requirements for quantifying geologic sequestration of CO_2 in association with enhanced oil recovery (EOR) operations. In several cases, the 2022 Data Quality Improvements Proposal included revisions that would resolve gaps in the current coverage of the GHGRP that leave out potentially significant sources of GHG emissions or end uses. The EPA also proposed revisions that clarified or updated provisions that may be unclear, and that would streamline calculation, monitoring, or reporting in specific provisions in part 98 to provide flexibility or increase the efficiency of data collection. The EPA included a request for comment on expanding the GHGRP to include several new source categories (see section IV. of the preamble to the 2022 Data Quality Improvements Proposal at 87 FR 37016) and requested comment on potential future amendments to add new calculation, monitoring, and reporting requirements for these categories. The EPA also proposed confidentiality determinations for new or substantially revised data reporting elements that would be amended under the proposed rule, as well as for certain existing data elements for which the EPA proposed a new or revised determination. The EPA received comments on the 2022 Data Quality Improvements Proposal from June 21, 2022, through October 6, 2022.

The EPA subsequently proposed additional amendments to part 98 where the Agency had received or identified new information to further improve the data collected under the GHGRP. The 2023 Supplemental Proposal included amendments that were informed by a review of comments and information provided by stakeholders on the 2022 Data Quality Improvements Proposal, as well as newly proposed amendments that the EPA had identified from program implementation, *e.g.,* where additional data would improve verification of data reported to the GHGRP or would further aid our understanding of changing industry emission trends. The 2023 Supplemental Proposal included a proposed comprehensive update to the GWPs in table A–1 to subpart A of part 98; proposed amendments to establish new subparts with specific reporting provisions under part 98 for five new source categories; and several proposed revisions where the EPA had identified new data supporting improvements to the calculation, monitoring, and recordkeeping requirements. The 2023 Supplemental Proposal also clarified or corrected specific proposed provisions of the 2022 Data Quality Improvements Proposal. The amendments included in the 2023 Supplemental Proposal were proposed as part of the EPA's continued efforts to address potential data gaps and improve the quality of the data collected in the GHGRP. The EPA also proposed confidentiality determinations for new or substantially revised data reporting elements that would be revised under the supplemental proposed amendments. The EPA received comments on the 2023 Supplemental Proposal from May 22, 2023, through July 21, 2023.

The revisions included in the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal were based on the EPA's assessment of advances in scientific understanding of GHG emissions sources, updated guidance on GHG estimation methods, and a review of the data collected and emissions trends established following more than 10 years of implementation of the program. The EPA is finalizing amendments and confidentiality determinations in this action, with certain changes from the proposed rules following consideration of comments submitted and based on the EPA's updated assessment. The revisions reflect the EPA's efforts to update and improve the GHGRP by better capturing the changing landscape of GHG emissions, providing for more complete coverage of U.S. GHG emission sources, and providing a more comprehensive approach to understanding GHG emissions. Responses to major comments submitted on the proposed amendments from the 2022 Data Quality Improvement Proposal and the 2023 Supplemental Proposal considered in the development of this final rule can be found in sections III. and VI. of this preamble. Documentation of all comments received as well as the EPA's responses can be found in the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule,'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

This final rule does not address implementation of provisions of the Inflation Reduction Act, which was signed into law on August 16, 2022. Section 60113 of the Inflation Reduction Act amended the CAA by adding section 136, ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.'' Although the EPA proposed amendments to subpart W of part 98 (Petroleum and Natural Gas Systems) in the 2022 Data Quality Improvements Proposal, these were developed prior to the Congressional direction provided in CAA section 136. The EPA noted in the preamble to the 2023 Supplemental Proposal (see section I.B., 88 FR 32855) that we intend to issue one or more separate actions to implement the requirements of CAA section 136, including revisions to certain requirements of subpart W. Subsequently, the EPA published a proposed rule for subpart W on August 1, 2023 (88 FR 50282, hereinafter referred to as the ''2023 Subpart W Proposal''), as well as a proposed rule to implement CAA section 136(c), ''Waste Emissions Charge,'' that was signed by the Administrator on January 12, 2024 and published on January 26, 2024 (89 FR 5318),[1] to comply with CAA section 136. As discussed in the 2023 Subpart W Proposal, the EPA considered the 2022 Data Quality Improvements Proposal as well as additional proposed revisions in the development of the 2023 Subpart W Proposal. Accordingly, the EPA is not taking final action on the revisions to subpart W, including harmonizing revisions to subparts A (General Provisions) and C (General Stationary Fuel Combustion Sources) related to subpart W, that were proposed in the 2022 Data Quality Improvements Proposal in this final rule.

D. Legal Authority

The EPA is finalizing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the *Mandatory Reporting of Greenhouse Gases* final rule (74 FR 56260, October 30, 2009), CAA section 114(a)(1) provides the EPA authority to require the information gathered by this rule because such data will inform and are relevant to the EPA's carrying out of a variety of CAA provisions. Thus, when promulgating amendments to the GHGRP, the EPA has assessed the reasonableness of requiring the information to be provided and explained how the data are relevant to the EPA's ability to carry out the provisions of the CAA. See the preambles to the proposed GHG

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[1] CAA section 136(c), ''Waste Emissions Charge,'' directs the Administrator to impose and collect a charge on methane (CH_4) emissions that exceed statutorily specified waste emissions thresholds from an owner or operator of an applicable facility that reports more than 25,000 metric tons carbon dioxide equivalent pursuant to the Greenhouse Gas Reporting Rule's requirements for the petroleum and natural gas systems source category (codified as subpart W in EPA's Greenhouse Gas Reporting Rule regulations).

Reporting Rule (74 FR 16448, April 10, 2009) and the final GHG Reporting Rule (74 FR 56260, October 30, 2009) for further discussion of this authority. Additionally, in enacting CAA section 136 (discussed above in preamble section I.C.), Congress implicitly recognized EPA's appropriate use of CAA authority in promulgating the GHGRP. The provisions of CAA section 136 reference and are in part based on the Greenhouse Gas Reporting Rule requirements under subpart W for the petroleum and natural gas systems source category and require further revisions to subpart W for purposes of supporting implementation of section 136.

The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA (see also section VIII.L. of this preamble). Section 307(d) contains a set of procedures relating to the issuance and review of certain CAA rules.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing final confidentiality determinations for the new or substantially revised data elements required by these amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information (excluding emission data) that qualifies for confidential treatment.

II. Overview of Final Revisions to 40 CFR Part 98 and 40 CFR Part 9

Relevant to this final rule, the EPA previously proposed revisions to part 98 in two separate documents: the 2022 Data Quality Improvements Proposal (June 21, 2022, 87 FR 36920) and the 2023 Supplemental Proposal (May 22, 2023, 88 FR 32852). In the proposed rules, the EPA identified two primary categories of revisions that we are finalizing in this rule. First, the EPA identified revisions that would modify the rule to improve the quality of the data collected and better inform the EPA's understanding of U.S. GHG emissions sources. Specifically, the EPA identified six types of revisions to improve the quality of the data collected under part 98 that we are finalizing in this rule, as follows:

- Revisions to table A–1 to the General Provisions of part 98 to update GWPs to reflect advances in scientific knowledge and better characterize the climate impacts of certain GHGs, by including values agreed to under the United Nations Framework Convention on Climate Change, and to maintain comparability and consistency with the Inventory of U.S. Greenhouse Gas Emissions and Sinks (hereafter referred to as "the Inventory") and other analyses produced by the EPA;
- Revisions to expand source categories or add new source categories to address potential gaps in reporting of data on U.S. GHG emissions or supply in order to improve the accuracy and completeness of the data provided by the GHGRP;
- Amendments to update emission factors to incorporate new measurement data that more accurately reflect industry emissions;
- Revisions to refine existing emissions calculation methodologies to reflect an improved understanding of emissions sources and end uses of GHGs, or to incorporate more recent research on GHG emissions or formation;
- Additions or modifications to reporting requirements to eliminate data gaps and improve verification of emissions estimates; and
- Revisions that clarify requirements that reporters have previously found vague to ensure that accurate data are being collected, and editorial corrections or harmonizing changes that will improve the public's understanding of the rule.

Second, the EPA identified revisions that would streamline the calculation, monitoring, or reporting requirements of part 98 to provide flexibility or increase the efficiency of data collection. In the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Notice, the EPA identified several streamlining revisions that we are finalizing in this rule, as follows:

- Revisions to applicability criteria for certain industry sectors without the 25,000 $mtCO_2e$ per year reporting threshold to account for changes in usage of certain GHGs, or where the current applicability estimation methodology may overestimate emissions;
- Revisions that provide flexibility for and simplify monitoring and calculation methods where further monitoring and data collection will not likely significantly improve our understanding of emission sources at this time, or where we currently allow similar less burdensome methodologies for other sources; and
- Revisions to reported data elements or recordkeeping where the current requirements are redundant or where reported data are not currently useful for verification or analysis, or for which continued collection of the data at the same frequency will not likely provide new insights or knowledge of the industry sector, emissions, or trends at this time.

The revisions included in this final rule will advance the EPA's goal of updating the GHGRP to reflect advances in scientific knowledge, better reflect the EPA's current understanding of U.S. GHG emissions and trends and improve data collection and reporting to better understand emissions from specific sectors or inform future policy decisions under the CAA. The types of streamlining revisions we are finalizing will simplify requirements while maintaining the quality of the data collected under part 98, where continued collection of information assists in evaluation and support of EPA programs and policies.

The EPA has frequently considered and relied on data collected under the GHGRP to carry out provisions of the CAA; to inform policy options; and to support regulatory and non-regulatory actions. For example, GHGRP landfill data from subpart HH of part 98 (Municipal Solid Waste Landfills) were previously analyzed to inform the development of the 2016 new source performance standards (NSPS) and emission guidelines (EG) for landfills (89 FR 59322; August 29, 2016). Specifically, the EPA used data from part 98 reporting to update the characteristics and technical attributes of over 1,200 landfills in the EPA's landfills data set, as well as to estimate emission reductions and costs, to inform the revised performance standards. Most recently, the EPA used GHGRP data collected under subparts RR (Geologic Sequestration of Carbon Dioxide) and UU (Injection of Carbon Dioxide) of part 98 to inform the development of the proposed NSPS and EG for GHG emissions from fossil fuel-fired electric generating units (EGUs) (88 FR 33240, May 23, 2023, hereafter "EGU NSPS/EG proposed rule"), including to assess the geographic availability of geologic sequestration and enhanced oil recovery. These final revisions to the GHGRP will, as discussed herein, improve the GHG emissions data and supplier data that is collected under the GHGRP to better inform the EPA in carrying out provisions of the CAA (such as providing a better understanding of upstream production, downstream emissions, and potential impacts) and otherwise supporting the continued development of climate and air quality standards under the CAA.

As the EPA has explained since the GHGRP was first promulgated, the data also will inform the EPA's implementation of CAA section 103(g) regarding improvements in nonregulatory strategies and technologies for preventing or reducing air pollutants (*e.g.,* EPA's voluntary

GHG reduction programs such as the non-CO_2 partnership programs and ENERGY STAR) (74 FR 56265). The final rule will support the overall goals of the GHGRP to collect high-quality GHG data and to incorporate metrics and methodologies that reflect scientific updates. For example, we are finalizing revisions to table A–1 to subpart A of part 98 to update the chemical-specific GWP values of certain GHGs to (1) reflect GWPs from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (hereinafter referred to as ''AR5''); [2] (2) for certain GHGs that do not have chemical-specific GWPs listed in AR5, to adopt GWP values from the IPCC Sixth Assessment Report (hereinafter referred to as ''AR6''); [3] and (3) to revise and expand the set of default GWPs which are applied to GHGs for which peer-reviewed chemical-specific GWPs are not available.

In several cases, we are finalizing updates to emissions and default factors where we have received or identified updated measurement data. For example, we are finalizing updates to the default biogenic fraction for tire combustion in subpart C of part 98 (General Stationary Fuel Combustion) based on updated data obtained by the EPA on the weighted average composition of natural rubber in tires, allowing for the estimation of an emission factor that is more representative of these sources. Similarly, we are finalizing updates to the emission factors and default destruction and removal efficiency values in subpart I of part 98 (Electronics Manufacturing). The updated emission factors are based on newly submitted data from the 2017 and 2020 technology assessment reports submitted under the GHGRP with RY2016 and RY2019 annual reports, as well as consideration of new emission factors available in the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories* (hereafter ''2019 Refinement'').[4]

In other cases, we are finalizing updates to calculation methodologies to incorporate updates that are based on an improved understanding of emission sources. For example, for subpart I of part 98 (Electronics Manufacturing), the EPA is implementing emissions estimation improvements from the 2019 Refinement such as updates to the method used to calculate the fraction of fluorinated input gases and byproducts exhausted from tools with abatement systems during stack tests; revising equations that calculate the weighted average DREs for individual fluorinated greenhouse gases (F–GHGs) across process types; requiring that all stack systems be tested if the stack test method is used; and updating a set of equations that will more accurately account for emissions when pre-control emissions of a F–GHG approach or exceed the consumption of that gas during the test period. For subpart Y (Petroleum Refineries), we are amending the calculation methodology for delayed coking units to more accurately reflect the activities conducted at certain facilities that were not captured by the current emissions estimation methodology, which relies on a steam generation model. The incorporation of updated metrics and methodologies will improve the quality and accuracy of the data collected under the GHGRP, increase the Agency's understanding of the relative distribution of GHGs that are emitted, and better inform EPA policy and programs under the CAA.

The improvements to part 98 will further provide a more comprehensive, nationwide GHG emissions profile reflective of the origin and distribution of GHG emissions in the United States and will more accurately inform EPA policy options for potential regulatory or non-regulatory CAA programs. The EPA is finalizing several amendments that will reduce gaps in the reporting of GHG emissions and supply from specific sectors, including the broadening of existing source categories; and establishing new source categories that will add calculation, monitoring, reporting, and recordkeeping requirements for certain sectors of the economy. The final revisions add five new source categories, including coke calcining; ceramics manufacturing; calcium carbide production; caprolactam, glyoxal, and glyoxylic acid production; and facilities conducting geologic sequestration of carbon dioxide with enhanced oil recovery. These source categories were identified upon evaluation of emission sources that potentially contribute significant GHG emissions that are not currently reported or where facilities representative of these source categories may currently report under another part 98 source category using methodologies that may not provide complete or accurate emissions. Additionally, the inclusion of certain source categories will improve the completeness of the emissions estimates presented in the Inventory, such as collection of data on ceramics manufacturing; calcium carbide production; and caprolactam, glyoxal, and glyoxylic acid production. The EPA is also finalizing updates to certain subparts to add reporting of new emissions or emissions sources for existing sectors to address potential gaps in reporting. For example, we are adding requirements for the monitoring, calculation, and reporting of F–GHGs other than sulfur hexafluoride (SF_6) and perfluorocarbons (PFCs) under subparts DD (Electrical Equipment and Distribution Equipment Use) and SS (Electrical Equipment Manufacture or Refurbishment) to account for the introduction of alternative technologies and replacements for SF_6.

Likewise, we are finalizing revisions that will improve reporting under subpart HH to better account for CH_4 emissions from these facilities. Following review of recent studies indicating that CH_4 emissions from landfills may be considerably higher than what is currently reported to part 98 due in part to emissions from poorly operating gas collection systems or destruction devices, we are revising the calculation methodologies in subpart HH to better account for these scenarios. These changes are necessary for the EPA to continue to analyze the relative emissions and distribution of emissions from specific industries, improve the overall quality of the data collected under the GHGRP, and better inform future EPA policy and programs under the CAA. For example, the final revisions to subpart HH will be used to further improve the data in the EPA's landfills data set by providing more

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[2] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. The GWPs are listed in table 8.A.1 of Appendix 8.A: Lifetimes, Radiative Efficiencies and Metric Values, which appears on pp. 731–737 of Chapter 8, ''Anthropogenic and Natural Radiative Forcing.''

[3] Smith, C., Z.R.J. Nicholls, K. Armour, W. Collins, P. Forster, M. Meinshausen, M.D. Palmer, and M. Watanabe, 2021: The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity Supplementary Material. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Available from *www.ipcc.ch/* The AR6 GWPs are listed in table 7.SM.7, which appears on page 16 of the Supplementary Material.

[4] Intergovernmental Panel on Climate Change. 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Calvo Buendia, E., Tanabe, K., Kranjc, A., Baasansuren, J., Fukuda, M., Ngarize, S., Osako, A., Pyrozhenko, Y., Shermanau, P. and Federici, S. (eds). Published: IPCC, Switzerland. 2019. *https://www.ipcc-nggip.iges.or.jp/public/2019rf/index.html.*

comprehensive and accurate information on landfill emissions and the efficacy of gas collection systems and destruction devices.

The final revisions also help ensure that the data collected in the GHGRP can be compared to the data collected and presented by other EPA programs under the CAA. For example, we are finalizing several revisions to the reporting requirements for subpart HH, including more clearly identifying reporting elements associated with each gas collection system, each measurement location within a gas collection system, and each control device associated with a measurement location in subpart HH of part 98. These revisions can be used to estimate the relative volume of gas flared versus sent to landfill-gas-to-energy projects to better understand the amount of recovered CH_4 that is beneficially used in energy recovery projects. Understanding the energy recovery of these facilities is critical for evaluating and identifying progress towards renewable energy targets. Specifically, these data will allow the Agency to identify industry-specific trends of beneficial use of landfill gas, communicate best operating practices for reducing GHG emissions, and evaluate options for expanding the use of these best practices or other potential policy options under the CAA.

Similarly, we are finalizing revisions to clarify subpart RR (Geologic Sequestration of Carbon Dioxide) and add subpart VV (Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916) to part 98. Subpart VV provides for the reporting of incidental CO_2 storage associated with enhanced oil recovery based on the CSA Group (CSA)/American National Standards Institute (ANSI) International Standards Organization (ISO) 27916:19.

In the EGU NSPS/EG proposed rule, the EPA proposed that any affected EGU that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the CO_2 underground must assure that the CO_2 is managed at a facility reporting under subpart RR or new subpart VV of part 98. As such, this final rule complements the EGU NSPS/EG proposed rule.

In other cases, the revisions include collection of data that could be compared to other national and international inventories, improving, for example, the estimates provided to the Inventory. For instance, we are finalizing revisions to subpart N (Glass Production) to require reporting of the annual quantities of cullet (*i.e.,* recycled scrap glass) used as a raw material. Because differences in the quantities of cullet used can lead to variations in emissions from the production of different glass types, the annual quantities of cullet used will provide a useful metric for understanding variations and differences in emissions estimates as well as improve the analysis, transparency, and accuracy of the glass manufacturing sector in the Inventory and other EPA programs. Likewise, the addition of reporting for new source categories will improve the completeness of the emissions estimates presented in the Inventory, such as collection of data on ceramics manufacturing, calcium carbide production, and caprolactam, glyoxal, and glyoxylic acid production.

The EPA is finalizing several amendments to improve verification of the annual GHG reports. For example, we are finalizing amendments to subpart H (Cement Production) to collect additional data including annual averages for certain chemical composition input data on a facility-basis, which the Agency will use to build verification checks. These edits will provide the EPA the ability to check reported emissions data from subpart H reporters using both the mass balance and direct measurement estimation methods, allowing the EPA to back-estimate process emissions, which will result in more accurate reporting. Similarly, we are amending subparts OO (Suppliers of Industrial Greenhouse Gases) and QQ (Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams) of part 98 to require reporting of the Harmonized Tariff System code for each F–GHG, fluorinated heat transfer fluid (F–HTF), or nitrous oxide (N_2O) shipped, which will reduce instances of reporting where the data provided is unclear or unable to be compared to outside data sources for verification.

Lastly, the changes in this final rule will further advance the ability of the GHGRP to provide access to quality data on greenhouse gas emissions. Since its implementation, the collection of data under the GHGRP has allowed the Agency and relevant stakeholders to identify changes in industry and emissions trends, such as transitions in equipment technology or use of alternative lower-GWP greenhouses gases, that may be beneficial for informing other EPA programs under the CAA. The GHGRP provides an important data resource for communities and the public to understand GHG emissions. Since facilities are required to use prescribed calculation and monitoring methods, emissions data can be compared and analyzed, including locations of emissions sources. GHGRP data are easily accessible to the public via the EPA's online data publication tool, also known as FLIGHT at: *https://ghgdata.epa.gov/ghgp/main.do.* FLIGHT allows users to view and sort GHG data for every reporting year starting with 2010 from over 8,000 entities in a variety of ways including by location, industrial sector, and type of GHG emitted. This powerful data resource provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments. Overall, the final revisions in this action will improve the quality of the data collected under the program and available to communities.

These final revisions will, as such, maximize the effectiveness of part 98. Section III. of this preamble describes the specific changes that we are finalizing for each subpart to part 98 in more detail. Additional discussion of the benefits of the final rule are in section VII. of this preamble.

Additionally, we are finalizing a technical amendment to 40 CFR part 9 to update the table that lists the OMB control numbers issued under the PRA to include the information collection request (ICR) for 40 CFR part 98. This amendment satisfies the display requirements of the PRA and OMB's implementing regulations at 5 CFR part 1320 and is further described in section IV. of this preamble.

III. Final Revisions to Each Subpart of Part 98 and Summary of Comments and Responses

This section summarizes the final amendments to each part 98 subpart, as generally described in section II. of this preamble. Major changes to the final rule as compared to the proposed revisions are identified in this section. The amendments to each subpart are followed by a summary of the major comments on those amendments, and the EPA's responses to those comments. Other minor corrections and clarifications are reflected in the final redline regulatory text in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2019–0424).

A. Subpart A—General Provisions

The EPA is finalizing several amendments to subpart A of part 98 (General Provisions) as proposed. In some cases, we are finalizing the proposed amendments with revisions. Section III.A.1. of this preamble discusses the final revisions to subpart A. The EPA received several comments on the proposed subpart A revisions which are discussed in section III.A.2.

of this preamble. We are not finalizing the proposed confidentiality determinations for data elements that were included in the proposed revisions to subpart A, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart A

This section summarizes the final amendments to subpart A. Major changes in this final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart A can be found in section III.A.2. of this preamble. Additional information for these amendments and their supporting basis is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Revisions to Global Warming Potentials

As proposed, we are revising table A–1 to subpart A of part 98 to reflect more accurate GWPs to better characterize the climate impacts of individual GHGs and to ensure continued consistency with other U.S. climate programs, including the Inventory. The amendments to the GWPs in table A–1 that we are finalizing in this document are discussed in this section of this preamble. The EPA's response to comments received on the proposed revisions to table A–1 are in section III.A.2.a. of this preamble.

In the 2022 Data Quality Improvements Proposal, the EPA proposed two updates to table A–1 to subpart A of part 98 to update GWP values to reflect advances in scientific knowledge. First, we proposed to adopt a chemical-specific GWP of 0.14 for carbonic difluoride (COF_2) using the atmospheric lifetime and radiative efficiency published by the World Meteorological Organization (WMO) in its Scientific Assessment of Ozone Depletion.[5] We also proposed to expand one of the F–GHG groups to which a default GWP is assigned. Default GWPs are applied to GHGs for which peer-reviewed chemical-specific GWPs are not available. Specifically, we proposed to expand the ninth F–GHG group in table A–1 to subpart A of part 98, which includes unsaturated PFCs, unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, fluorinated aldehydes, and fluorinated ketones, to include additional unsaturated fluorocarbons. Given the very short atmospheric lifetimes of unsaturated GHGs and review of available evaluations of individual unsaturated chlorofluorocarbons and unsaturated bromofluorocarbons in the 2018 WMO Scientific Assessment, we proposed to add unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, and unsaturated hydrobromochlorofluorocarbons to this F–GHG group, which will apply a default GWP of 1 to these compounds. Additional information on these amendments and their supporting basis is available in section III.A.1. of the preamble to the 2022 Data Quality Improvements Proposal.

As the 2022 Data Quality Improvements Proposal was nearing publication, the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) fully specified which GWPs countries should use for purposes of GHG reporting.[6] The EPA subsequently proposed a comprehensive update to table A–1 to subpart A of part 98 in the 2023 Supplemental Proposal, consistent with recent science and the UNFCCC decision. This update carried out the intent that the EPA expressed at the time the GHGRP was first promulgated and in subsequent updates to part 98 to periodically update table A–1 as science and UNFCCC decisions evolve. Specifically, the EPA proposed revisions to table A–1 to update the chemical-specific GWPs values of certain GHGs to reflect values from the IPCC AR5[7] and, for certain GHGs that do not have chemical-specific GWPs listed in AR5, to adopt GWP values from the IPCC AR6.[8] We proposed to adopt the AR5 and AR6 GWPs based on a 100-year time horizon. We also proposed to revise and expand the set of default GWPs in table A–1 for GHGs for which peer-reviewed chemical-specific GWPs are not available, including adding two new fluorinated GHG groups for saturated chlorofluorocarbons (CFCs) and for cyclic forms of unsaturated halogenated compounds, modifying the ninth F–GHG group to more clearly apply to non-cyclic unsaturated halogenated compounds, and updating the existing default GWP values to reflect values estimated from the chemical-specific GWPs that we proposed to adopt from AR5 and AR6. See sections II.A. and III.A.1. of the preamble to the 2023 Supplemental Proposal for additional information.

As proposed, we are amending table A–1 to subpart A of part 98 to update and add chemical-specific and default GWPs. Consistent with the 2021 UNFCCC decision, we are updating table A–1 to use, for GHGs with GWPs in AR5, the AR5 GWP values in table 8.A.1 (that reflect the climate-carbon feedbacks of CO_2 but not the GHG whose GWP is being evaluated), and for CH_4, the GWP that is not the GWP for fossil CH_4 in table 8.A.1 (*i.e.,* the GWP for CH_4 that does not reflect either the climate-carbon feedbacks for CH_4 or the atmospheric CO_2 that would result from the oxidation of CH_4 in the atmosphere). We are also updating table A–1 to adopt AR6 GWP values for 31 F–GHGs that have GWPs listed in AR6 but not AR5. Table 2 of this preamble lists the final GWP values for each GHG.

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[5] WMO. Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project–Report No. 58, 588 pp., Geneva, Switzerland, 2018. *www.esrl.noaa.gov/csd/assessments/ozone/2018/downloads/018OzoneAssessment.pdf.* Retrieved July 29, 2019. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

[6] As explained in section III.A.1. of the preamble to the 2023 Supplemental Proposal, the Parties to the UNFCCC specified the agreed-on GWPs in November 2021, which was too late to allow the EPA to consider proposing a comprehensive GWP update in the 2022 Data Quality Improvement Proposal.

[7] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. The GWPs are listed in table 8.A.1 of Appendix 8.A: Lifetimes, Radiative Efficiencies and Metric Values, which appears on pp. 731–737 of Chapter 8, ''Anthropogenic and Natural Radiative Forcing.''

[8] Smith, C., Z.R.J. Nicholls, K. Armour, W. Collins, P. Forster, M. Meinshausen, M.D. Palmer, and M. Watanabe, 2021: The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity Supplementary Material. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Pe´an, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Available from: *www.ipcc.ch/.* The AR6 GWPs are listed in table 7.SM.7, which appears on page 16 of the Supplementary Material.

TABLE 2—REVISED CHEMICAL-SPECIFIC GWPS FOR COMPOUNDS IN TABLE A–1

Name	CAS No.	Chemical formula	GWP (100-year)
Chemical-Specific GWPs			
Carbon dioxide	124–38–9	CO_2	1
Methane	74–82–8	CH_4	28
Nitrous oxide	10024–97–2	N_2O	265
Fully Fluorinated GHGs			
Sulfur hexafluoride	2551–62–4	SF_6	23,500
Trifluoromethyl sulphur pentafluoride	373–80–8	SF_5CF_3	17,400
Nitrogen trifluoride	7783–54–2	NF_3	16,100
PFC–14 (Perfluoromethane)	75–73–0	CF_4	6,630
PFC–116 (Perfluoroethane)	76–16–4	C_2F_6	11,100
PFC–218 (Perfluoropropane)	76–19–7	C_3F_8	8,900
Perfluorocyclopropane	931–91–9	c-C_3F_6	9,200
PFC–3–1–10 (Perfluorobutane)	355–25–9	C_4F_{10}	9,200
PFC–318 (Perfluorocyclobutane)	115–25–3	c-C_4F_8	9,540
Perfluorotetrahydrofuran	773–14–8	c-C_4F_8O	13,900
PFC–4–1–12 (Perfluoropentane)	678–26–2	C_5F_{12}	8,550
PFC–5–1–14 (Perfluorohexane, FC–72)	355–42–0	C_6F_{14}	7,910
PFC–6–1–12	335–57–9	C_7F_{16}; $CF_3(CF_2)_5CF_3$	7,820
PFC–7–1–18	307–34–6	C_8F_{18}; $CF_3(CF_2)_6CF_3$	7,620
PFC–9–1–18	306–94–5	$C_{10}F_{18}$	7,190
PFPMIE (HT–70)	NA	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	9,710
Perfluorodecalin (cis)	60433–11–6	Z–$C_{10}F_{18}$	7,240
Perfluorodecalin (trans)	60433–12–7	E–$C_{10}F_{18}$	6,290
Perfluorotriethylamine	359–70–6	$N(C_2F_5)_3$	10,300
Perfluorotripropylamine	338–83–0	$N(CF_2CF_2CF_3)_3$	9,030
Perfluorotributylamine	311–89–7	$N(CF_2CF_2CF_2CF_3)_3$	8,490
Perfluorotripentylamine	338–84–1	$N(CF_2CF_2CF_2CF_2CF_3)_3$	7,260
Saturated Hydrofluorocarbons (HFCs) With Two or Fewer Carbon-Hydrogen Bonds			
(4s,5s)-1,1,2,2,3,3,4,5-octafluorocyclopentane	158389–18–5	trans-cyc (-$CF_2CF_2CF_2CHFCHF$-)	258
HFC–23	75–46–7	CHF_3	12,400
HFC–32	75–10–5	CH_2F_2	677
HFC–125	354–33–6	C_2HF_5	3,170
HFC–134	359–35–3	$C_2H_2F_4$	1,120
HFC–134a	811–97–2	CH_2FCF_3	1,300
HFC–227ca	220732–84–8	$CF_3CF_2CHF_2$	2,640
HFC–227ea	431–89–0	C_3HF_7	3,350
HFC–236cb	677–56–5	$CH_2FCF_2CF_3$	1,210
HFC–236ea	431–63–0	CHF_2CHFCF_3	1,330
HFC–236fa	690–39–1	$C_3H_2F_6$	8,060
HFC–329p	375–17–7	$CHF_2CF_2CF_2CF_3$	2,360
HFC–43–10mee	138495–42–8	$CF_3CFHCFHCF_2CF_3$	1,650
Saturated Hydrofluorocarbons (HFCs) With Three or More Carbon-Hydrogen Bonds			
1,1,2,2,3,3-hexafluorocyclopentane	123768–18–3	cyc (-$CF_2CF_2CF_2CH_2CH_2$-)	120
1,1,2,2,3,3,4-heptafluorocyclopentane	1073290–77–4	cyc (-$CF_2CF_2CF_2CHFCH_2$-)	231
HFC–41	593–53–3	CH_3F	116
HFC–143	430–66–0	$C_2H_3F_3$	328
HFC–143a	420–46–2	$C_2H_3F_3$	4,800
HFC–10732	624–72–6	CH_2FCH_2F	16
HFC–10732a	75–37–6	CH_3CHF_2	138
HFC–161	353–36–6	CH_3CH_2F	4
HFC–245ca	679–86–7	$C_3H_3F_5$	716
HFC–245cb	1814–88–6	$CF_3CF_2CH_3$	4,620
HFC–245ea	24270–66–4	$CHF_2CHFCHF_2$	235
HFC–245eb	431–31–2	$CH_2FCHFCF_3$	290
HFC–245fa	460–73–1	$CHF_2CH_2CF_3$	858
HFC–263fb	421–07–8	$CH_3CH_2CF_3$	76
HFC–272ca	420–45–1	$CH_3CF_2CH_3$	144
HFC–365mfc	406–58–6	$CH_3CF_2CH_2CF_3$	804
Saturated Hydrofluoroethers (HFEs) and Hydrochlorofluoroethers (HCFEs) With One Carbon-Hydrogen Bond			
HFE–125	3822–68–2	CHF_2OCF_3	12,400
HFE–227ea	2356–62–9	$CF_3CHFOCF_3$	6,450
HFE–329mcc2	134769–21–4	$CF_3CF_2OCF_2CHF_2$	3,070
HFE–329me3	428454–68–6	$CF_3CFHCF_2OCF_3$	4,550
1,1,1,2,2,3,3-Heptafluoro-3-(1,2,2,2-tetrafluoroethoxy)-propane	3330–15–2	$CF_3CF_2CF_2OCHFCF_3$	6,490
Saturated HFEs and HCFEs With Two Carbon-Hydrogen Bonds			
HFE–134 (HG–00)	1691–17–4	CHF_2OCHF_2	5,560
HFE–236ca	32778–11–3	$CHF_2OCF_2CHF_2$	4,240
HFE–236ca12 (HG–10)	7807322–47–1	$CHF_2OCF_2OCHF_2$	5,350
HFE–236ea2 (Desflurane)	57041–67–5	$CHF_2OCHFCF_3$	1,790
HFE–236fa	20193–67–3	$CF_3CH_2OCF_3$	979

TABLE 2—REVISED CHEMICAL-SPECIFIC GWPS FOR COMPOUNDS IN TABLE A–1—Continued

Name	CAS No.	Chemical formula	GWP (100-year)
HFE–338mcf2	156053–88–2	$CF_3CF_2OCH_2CF_3$	929
HFE–338mmz1	26103–08–2	$CHF_2OCH(CF_3)_2$	2,620
HFE–338pcc13 (HG–01)	188690–78–0	$CHF_2OCF_2CF_2OCHF_2$	2,910
HFE–43–10pccc (H-Galden 1040x, HG–11)	E1730133	$CHF_2OCF_2OC_2F_4OCHF_2$	2,820
HCFE–235ca2 (Enflurane)	13838–16–9	CHF_2OCF_2CHFCl	583
HCFE–235da2 (Isoflurane)	26675–46–7	$CHF_2OCHClCF_3$	491
HG–02	205367–61–9	$HF_2C\text{-}(OCF_2CF_2)_2\text{-}OCF_2H$	2,730
HG–03	173350–37–3	$HF_2C\text{-}(OCF_2CF_2)_3\text{-}OCF_2H$	2,850
HG–20	249932–25–0	$HF_2C\text{-}(OCF_2)_2\text{-}OCF_2H$	5,300
HG–21	249932–26–1	$HF_2C\text{-}OCF_2CF_2OCF_2OCF_2O\text{-}CF_2H$	3,890
HG–30	188690–77–9	$HF_2C\text{-}(OCF_2)_3\text{-}OCF_2H$	7,330
1,1,3,3,4,4, 6,6,7,7,9,9, 10,10,12,12, 13,13,15, 15-eicosafluoro-2,5,8,11,14-Pentaoxapentadecane.	173350–38–4	$HCF_2O(CF_2CF_2O)_4CF_2H$	3,630
1,1,2-Trifluoro-2-(trifluoromethoxy)-ethane	84011–06–3	$CHF_2CHFOCF_3$	1,240
Trifluoro(fluoromethoxy)methane	2261–01–0	CH_2FOCF_3	751
Saturated HFEs and HCFEs With Three or More Carbon-Hydrogen Bonds			
HFE–143a	421–14–7	CH_3OCF_3	523
HFE–245cb2	22410–44–2	$CH_3OCF_2CF_3$	654
HFE–245fa1	84011–15–4	$CHF_2CH_2OCF_3$	828
HFE–245fa2	1885–48–9	$CHF_2OCH_2CF_3$	812
HFE–254cb1	425–88–7	$CH_3OCF_2CHF_2$	301
HFE–263fb2	460–43–5	$CF_3CH_2OCH_3$	1
HFE–263m1; R–E–143a	690–22–2	$CF_3OCH_2CH_3$	29
HFE–347mcc3 (HFE–7000)	375–03–1	$CH_3OCF_2CF_2CF_3$	530
HFE–347mcf2	171182–95–9	$CF_3CF_2OCH_2CHF_2$	854
HFE–347mmy1	2200732–84–2	$CH_3OCF(CF_3)_2$	363
HFE–347mmz1 (Sevoflurane)	2807323–86–6	$(CF_3)_2CHOCH_2F$	216
HFE–347pcf2	406–78–0	$CHF_2CF_2OCH_2CF_3$	889
HFE–356mec3	382–34–3	$CH_3OCF_2CHFCF_3$	387
HFE–356mff2	333–36–8	$CF_3CH_2OCH_2CF_3$	17
HFE–356mmz1	13171–18–1	$(CF_3)_2CHOCH_3$	14
HFE–356pcc3	160620–20–2	$CH_3OCF_2CF_2CHF_2$	413
HFE–356pcf2	50807–77–7	$CHF_2CH_2OCF_2CHF_2$	719
HFE–356pcf3	35042–99–0	$CHF_2OCH_2CF_2CHF_2$	446
HFE–365mcf2	2200732–81–9	$CF_3CF_2OCH_2CH_3$	58
HFE–365mcf3	378–16–5	$CF_3CF_2CH_2OCH_3$	0.99
HFE–374pc2	512–51–6	$CH_3CH_2OCF_2CHF_2$	627
HFE–449s1 (HFE–7100) Chemical blend	163702–07–6 163702–08–7	$C_4F_9OCH_3$ $(CF_3)_2CFCF_2OCH_3$.	421
HFE–569sf2 (HFE–7200) Chemical blend	163702–05–4 163702–06–5	$C_4F_9OC_2H_5$ $(CF_3)_2CFCF_2OC_2H_5$.	57
HFE–7300	132182–92–4	$(CF_3)_2CFCFOC_2H_5CF_2CF_2CF_3$	405
HFE–7500	297730–93–9	$n\text{-}C_3F_7CFOC_2H_5CF(CF_3)_2$	13
HG′-01	73287–23–7	$CH_3OCF_2CF_2OCH_3$	222
HG′-02	485399–46–0	$CH_3O(CF_2CF_2O)_2CH_3$	236
HG′-03	485399–48–2	$CH_3O(CF_2CF_2O)_3CH_3$	221
Difluoro(methoxy)methane	359–15–9	CH_3OCHF_2	144
2-Chloro-1,1,2-trifluoro-1-methoxyethane	425–87–6	CH_3OCF_2CHFCl	122
1-Ethoxy-1,1,2,2,3,3,3-heptafluoropropane	22052–86–4	$CF_3CF_2CF_2OCH_2CH_3$	61
2-Ethoxy-3,3,4,4,5-pentafluorotetrahydro-2,5-bis[1,2,2,2-tetrafluoro-1-(trifluoromethyl)ethyl]-furan.	920979–28–8	$C_{12}H_5F_{19}O_2$	56
1-Ethoxy-1,1,2,3,3,3-hexafluoropropane	380–34–7	$CF_3CHFCF_2OCH_2CH_3$	23
Fluoro(methoxy)methane	460–22–0	CH_3OCH_2F	13
1,1,2,2-Tetrafluoro-3-methoxy-propane; Methyl 2,2,3,3-tetrafluoropropyl ether	60598–17–6	$CHF_2CF_2CH_2OCH_3$	0.49
1,1,2,2-Tetrafluoro-1-(fluoromethoxy)ethane	37031–31–5	$CH_2FOCF_2CF_2H$	871
Difluoro(fluoromethoxy)methane	461–63–2	CH_2FOCHF_2	617
Fluoro(fluoromethoxy)methane	462–51–1	CH_2FOCH_2F	130
Saturated Chlorofluorocarbons (CFCs)			
E–R316c	3832–15–3	trans-cyc $(\text{-}CClFCF_2CF_2CClF\text{-})$	4,230
Z–R316c	3934–26–7	cis-cyc $(\text{-}CClFCF_2CF_2CClF\text{-})$	5,660
Fluorinated Formates			
Trifluoromethyl formate	85358–65–2	$HCOOCF_3$	588
Perfluoroethyl formate	313064–40–3	$HCOOCF_2CF_3$	580
1,2,2,2-Tetrafluoroethyl formate	481631–19–0	$HCOOCHFCF_3$	470
Perfluorobutyl formate	197218–56–7	$HCOOCF_2CF_2CF_2CF_3$	392
Perfluoropropyl formate	271257–42–2	$HCOOCF_2CF_2CF_3$	376
1,1,1,3,3,3-Hexafluoropropan-2-yl formate	856766–70–6	$HCOOCH(CF_3)_2$	333
2,2,2-Trifluoroethyl formate	32042–38–9	$HCOOCH_2CF_3$	33
3,3,3-Trifluoropropyl formate	1344118–09–7	$HCOOCH_2CH_2CF_3$	17
Fluorinated Acetates			
Methyl 2,2,2-trifluoroacetate	431–47–0	CF_3COOCH_3	52
1,1-Difluoroethyl 2,2,2-trifluoroacetate	1344118–13–3	$CF_3COOCF_2CH_3$	31
Difluoromethyl 2,2,2-trifluoroacetate	2024–86–4	$CF_3COOCHF_2$	27

TABLE 2—REVISED CHEMICAL-SPECIFIC GWPS FOR COMPOUNDS IN TABLE A–1—Continued

Name	CAS No.	Chemical formula	GWP (100-year)
2,2,2-Trifluoroethyl 2,2,2-trifluoroacetate	407–38–5	$CF_3COOCH_2CF_3$	7
Methyl 2,2-difluoroacetate	433–53–4	HCF_2COOCH_3	3
Perfluoroethyl acetate	343269–97–6	$CH_3COOCF_2CF_3$	2
Trifluoromethyl acetate	74123–20–9	CH_3COOCF_3	2
Perfluoropropyl acetate	1344118–10–0	$CH_3COOCF_2CF_2CF_3$	2
Perfluorobutyl acetate	209597–28–4	$CH_3COOCF_2CF_2CF_2CF_3$	2
Ethyl 2,2,2-trifluoroacetate	383–63–1	$CF_3COOCH_2CH_3$	1
Carbonofluoridates			
Methyl carbonofluoridate	1538–06–3	$FCOOCH_3$	95
1,1-Difluoroethyl carbonofluoridate	1344118–11–1	$FCOOCF_2CH_3$	27
Fluorinated Alcohols Other Than Fluorotelomer Alcohols			
Bis(trifluoromethyl)-methanol	920–66–1	$(CF_3)_2CHOH$	182
2,2,3,3,4,4,5,5-Octafluorocyclopentanol	16621–87–7	cyc $(-(CF_2)_4CH(OH)-)$	13
2,2,3,3,3-Pentafluoropropanol	422–05–9	$CF_3CF_2CH_2OH$	19
2,2,3,3,4,4,4-Heptafluorobutan-1-ol	375–01–9	C_3F_7CH2OH	34
2,2,2-Trifluoroethanol	75–89–8	CF_3CH_2OH	20
2,2,3,4,4,4-Hexafluoro-1-butanol	382–31–0	$CF_3CHFCF_2CH_2OH$	17
2,2,3,3-Tetrafluoro-1-propanol	76–37–9	$CHF_2CF_2CH_2OH$	13
2,2-Difluoroethanol	359–13–7	CHF_2CH2OH	3
2-Fluoroethanol	371–62–0	CH_2FCH_2OH	1.1
4,4,4-Trifluorobutan-1-ol	461–18–7	$CF_3(CH_2)_2CH_2OH$	0.05
Non-Cyclic, Unsaturated Perfluorocarbons (PFCs)			
PFC–1114; TFE	116–14–3	$CF_2=CF_2$; C_2F_4	0.004
PFC–1216; Dyneon HFP	116–15–4	C_3F_6; $CF_3CF=CF_2$	0.05
Perfluorobut-2-ene	360–89–4	$CF_3CF=CFCF_3$	1.82
Perfluorobut-1-ene	357–26–6	$CF_3CF_2CF=CF_2$	0.10
Perfluorobuta-1,3-diene	685–63–2	$CF_2=CFCF=CF_2$	0.003
Non-Cyclic, Unsaturated Hydrofluorocarbons (HFCs) and Hydrochlorofluorocarbons (HCFCs)			
HFC–1132a; VF2	75–38–7	$C_2H_2F_2$, $CF_2=CH_2$	0.04
HFC–1141; VF	75–02–5	C_2H_3F, $CH_2=CHF$	0.02
(E)-HFC–1225ye	5595–10–8	$CF_3CF=CHF(E)$	0.06
(Z)-HFC–1225ye	507328–43–8	$CF_3CF=CHF(Z)$	0.22
Solstice 1233zd(E)	102687–65–0	$C_3H_2ClF_3$; $CHCl=CHCF_3$	1.34
HCFO–1233zd(Z)	99728–16–2	(Z)-$CF_3CH=CHCl$	0.45
HFC–1234yf; HFO–1234yf	754–12–1	$C_3H_2F_4$; $CF_3CF=CH_2$	0.31
HFC–1234ze(E)	1645–83–6	$C_3H_2F_4$; trans-$CF_3CH=CHF$	0.97
HFC–1234ze(Z)	29118–25–0	$C_3H_2F_4$; cis-$CF_3CH=CHF$; $CF_3CH=CHF$	0.29
HFC–1243zf; TFP	677–21–4	$C_3H_3F_3$, $CF_3CH=CH_2$	0.12
(Z)-HFC–1336	692–49–9	$CF_3CH=CHCF_3(Z)$	1.58
HFO–1336mzz(E)	66711–86–2	(E)-$CF_3CH=CHCF_3$	18
HFC–1345zfc	374–27–6	$C_2F_5CH=CH_2$	0.09
HFO–1123	359–11–5	$CHF=CF_2$	0.005
HFO–1438ezy(E)	14149–41–8	(E)-$(CF_3)_2CFCH=CHF$	8.2
HFO–1447fz	355–08–8	$CF_3(CF_2)_2CH=CH_2$	0.24
Capstone 42–U	19430–93–4	$C_6H_3F_9$, $CF_3(CF_2)_3CH=CH_2$	0.16
Capstone 62–U	2073291–17–2	$C_8H_3F_{13}$, $CF_3(CF_2)_5CH=CH_2$	0.11
Capstone 82–U	2160732–58–4	$C_{10}H_3F_{17}$, $CF_3(CF_2)_7CH=CH_2$	0.09
(e)-1-chloro-2-fluoroethene	460–16–2	(E)-$CHCl=CHF$	0.004
3,3,3-trifluoro-2-(trifluoromethyl)prop-1-ene	382–10–5	$(CF_3)_2C=CH_2$	0.38
Non-Cyclic, Unsaturated CFCs			
CFC–1112	598–88–9	$CClF=CClF$	0.13
CFC–1112a	79–35–6	$CCl_2=CF_2$	0.021
Non-Cyclic, Unsaturated Halogenated Ethers			
PMVE; HFE–216	1187–93–5	$CF_3OCF=CF_2$	0.17
Fluoroxene	406–90–6	$CF_3CH_2OCH=CH_2$	0.05
Methyl-perfluoroheptene-ethers	N/A	$CH_3OC_7F_{13}$	15
Non-Cyclic, Unsaturated Halogenated Esters			
Ethenyl 2,2,2-trifluoroacetate	433–28–3	$CF_3COOCH=CH_2$	0.008
Prop-2-enyl 2,2,2-trifluoroacetate	383–67–5	$CF_3COOCH_2CH=CH_2$	0.007
Cyclic, Unsaturated HFCs and PFCs			
PFC C–1418	559–40–0	c-C_5F_8	2
Hexafluorocyclobutene	697–11–0	cyc $(-CF=CFCF_2CF_2-)$	126
1,3,3,4,4,5,5-heptafluorocyclopentene	1892–03–1	cyc $(-CF_2CF_2CF_2CF=CH-)$	45
1,3,3,4,4-pentafluorocyclobutene	374–31–2	cyc $(-CH=CFCF_2CF_2-)$	92
3,3,4,4-tetrafluorocyclobutene	2714–38–7	cyc $(-CH=CHCF_2CF_2-)$	26

TABLE 2—REVISED CHEMICAL-SPECIFIC GWPS FOR COMPOUNDS IN TABLE A–1—Continued

Name	CAS No.	Chemical formula	GWP (100-year)
Fluorinated Aldehydes			
3,3,3-Trifluoro-propanal	460–40–2	CF_3CH_2CHO	0.01
Fluorinated Ketones			
Novec 1230 (perfluoro (2-methyl-3-pentanone))	756–13–8	$CF_3CF_2C(O)CF(CF3)_2$	0.1
1,1,1-trifluoropropan-2-one	421–50–1	CF_3COCH_3	0.09
1,1,1-trifluorobutan-2-one	381–88–4	$CF_3COCH_2CH_3$	0.095
Fluorotelomer			
3,3,4,4,5,5,6,6,7,7,7-Undecafluoroheptan-1-ol	185689–57–0	$CF_3(CF_2)_4CH_2CH_2OH$	0.43
3,3,3-Trifluoropropan-1-ol	2240–88–2	$CF_3CH_2CH_2OH$	0.35
3,3,4,4,5,5,6,6,7,7,8,8,9,9,9-Pentadecafluorononan-1-ol	755–02–2	$CF_3(CF_2)_6CH_2CH_2OH$	0.33
3,3,4,4,5,5,6,6,7,7,8,8,9,9,10,10,11,11,11-Nonadecafluoroundecan-1-ol	87017–97–8	$CF_3(CF_2)_8CH_2CH_2OH$	0.19
Fluorinated GHGs With Carbon-Iodine Bond(s)			
Trifluoroiodomethane	2314–97–8	CF_3I	0.4
Remaining Fluorinated GHGs with Chemical-Specific GWPs			
Dibromodifluoromethane (Halon 1202)	75–61–6	CBr_2F_2	231
2-Bromo-2-chloro-1,1,1-trifluoroethane (Halon-2311/Halothane)	151–67–7	$CHBrClCF_3$	41
Heptafluoroisobutyronitrile	42532–60–5	$(CF_3)_2CFCN$	2,750
Carbonyl fluoride	353–50–4	COF_2	0.14

As proposed, we are also amending table A–1 to subpart A of part 98 to revise the default GWPs. We are modifying the default GWP groups to add a group for saturated CFCs and a group for cyclic forms of unsaturated halogenated compounds. Based on the numerical differences between the GWP for cyclic unsaturated halogenated compounds and non-cyclic unsaturated halogenated compounds, we are also modifying the ninth F–GHG group to reflect non-cyclic forms of unsaturated halogenated compounds. The amendments update the default GWPs of each group based on the average of the updated chemical-specific GWPs (adopted from either the IPCC AR5 or AR6) for the compounds that belong to that group. We are also finalizing our proposal to rename the fluorinated GHG group ''Other fluorinated GHGs'' to ''Remaining fluorinated GHGs.'' The new and revised fluorinated GHG groups and their new and revised GWPs are listed in table 3 of this preamble.

TABLE 3—FLUORINATED GHG GROUPS AND DEFAULT GWPS FOR TABLE A–1

Fluorinated GHG group	GWP (100-year)
Fully fluorinated GHGs	9,200
Saturated hydrofluorocarbons (HFCs) with two or fewer carbon-hydrogen bonds.	3,000
Saturated HFCs with three or more carbon-hydrogen bonds.	840
Saturated hydrofluoroethers (HFEs) and hydrochlorofluoroethers (HCFEs) with one carbon-hydrogen bond.	6,600
Saturated HFEs and HCFEs with two carbon-hydrogen bonds.	2,900
Saturated HFEs and HCFEs with three or more carbon-hydrogen bonds.	320
Saturated chlorofluorocarbons (CFCs).	4,900
Fluorinated formates	350
Cyclic forms of the following: unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated CFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated bromofluorocarbons (BFCs), unsaturated bromochlorofluorocarbons (BCFCs), unsaturated hydrobromofluorocarbons (HBFCs), unsaturated hydrobromochlorofluorocarbons (HBCFCs), unsaturated halogenated ethers, and unsaturated halogenated esters.	58
Fluorinated acetates, carbonofluoridates, and fluorinated alcohols other than fluorotelomer alcohols.	25
Fluorinated aldehydes, fluorinated ketones, and non-cyclic forms of the following: unsaturated PFCs, unsaturated HFCs, unsaturated CFCs, unsaturated HCFCs, unsaturated BFCs, unsaturated BCFCs, unsaturated HBFCs, unsaturated HBCFCs, unsaturated halogenated ethers, and unsaturated halogenated esters.	1
Fluorotelomer alcohols	1
Fluorinated GHGs with carbon-iodine bond(s).	1
Remaining fluorinated GHGs	1,800

b. Other Revisions To Improve the Quality of Data Collected for Subpart A

The EPA is finalizing several revisions to improve the quality of data collected for subpart A as proposed. In some cases, we are finalizing the proposed amendments with revisions. First, we are clarifying in 40 CFR 98.2(i)(1) and (2), as proposed, that the provision to allow cessation of reporting or ''off-ramping,'' due to meeting either the 15,000 mtCO_2e level or the 25,000 mtCO_2e level for the number of years specified in 40 CFR 98.2(i), is based on the CO_2e reported, calculated in accordance with 40 CFR 98.3(c)(4)(i) (*i.e.,* the annual emissions report value as specified in that provision). The final amendments also clarify that after an owner or operator off-ramps, the owner or operator must use equation A–1 to subpart A and follow the requirements of 40 CFR 98.2(b)(4) (the emission estimation methods used for determination of applicability) in subsequent years to determine if emissions exceed the 25,000 mtCO$_2$e applicability threshold and whether the facility or supplier must resume reporting.

Additionally, the EPA is amending 40 CFR 98.2(f)(1) and adding new paragraph (k) as proposed to clarify the calculation of GHG quantities for comparison to the 25,000 mtCO$_2$e threshold for importers and exporters of industrial greenhouse gases. The final amendments to 40 CFR 98.2(f)(1) state that importers and exporters must include the F–HTFs that are imported or exported during the year. New paragraph (k) specifies how to calculate the quantities of F–GHGs and F–HTFs destroyed for purposes of comparing them to the 25,000 mtCO$_2$e threshold for stand-alone industrial F–GHG or F–HTF destruction facilities. The EPA is also finalizing as proposed revisions to 40 CFR 98.3(h)(4) to limit the total number of days a reporter can request to extend the time period for resolving a substantive error, either by submitting a revised report or providing information demonstrating that the previously submitted report does not contain the substantive error, to 180 days. Specifically, the Administrator will only approve extension requests for a total of 180 days from the initial notification of a substantive error. See section III.A.1. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these revisions and their supporting basis.

We are finalizing minor clarifications to the reporting and special provisions for best available monitoring methods in 40 CFR 98.3(k) and (l) as proposed, which apply to owners or operators of facilities or suppliers that first become subject to any subpart of part 98 due to amendment(s) to table A–1 to subpart A. The final requirements revise the term ‘‘published’’ to add ‘‘in the **Federal Register** as a final rulemaking’’ to clarify the EPA's intent that the requirements apply to facilities or suppliers that are first subject to the GHGRP in the year after the year the GWP is published as part of a final rule.

The EPA is finalizing an additional edit to subpart A to the electronic reporting provisions of 40 CFR 98.5(b). The revisions clarify that 40 CFR 98.5(b) applies to any data that is specified as verification software records in a subpart's applicable recordkeeping section.

The EPA is finalizing several revisions to subpart A to incorporate new and revised source categories. We are revising tables A–3 and A–4 to subpart A to clarify the reporting applicability for facilities included in the new source categories of coke calcining; ceramics manufacturing; calcium carbide production; caprolactam, glyoxal, and glyoxylic acid production; and facilities conducting geologic sequestration of carbon dioxide with enhanced oil recovery. We are revising table A–3 to subpart A to add new subparts that are ‘‘all-in’’ source categories, including subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916) (section III.AA. of this preamble), subpart WW (Coke Calciners) (section III.BB. of this preamble), subpart XX (Calcium Carbide Production) (section III.CC. of this preamble), and subpart YY (Caprolactam, Glyoxal, and Glyoxylic Acid Production) (section III.DD. of this preamble). We are revising table A–4 to add new subpart ZZ (Ceramics Manufacturing) and assign a threshold of 25,000 mtCO$_2$e, as proposed. As discussed in section III.EE. of this preamble, subpart ZZ to part 98 applies to certain ceramics manufacturing processes that exceed a minimum production level (*i.e.,* annually consume at least 2,000 tons of carbonates, either as raw materials or as a constituent in clay, heated to a temperature sufficient to allow the calcination reaction to occur) and that exceed the 25,000 mtCO$_2$e threshold. The revisions to tables A–3 and A–4 to subpart A clarify that these new source categories apply in RY2025 and future years.

The EPA is finalizing several revisions to defined terms in 40 CFR 98.6 as proposed to provide further clarity. These revisions to definitions include:

- Revising the definition of ‘‘bulk’’ to clarify that the import and export of gas includes small containers and does not exclude a minimum container size below which reporting will not be required (except for small shipments (*i.e.,* those including less than 25 kilograms)), and to align with the definition of ‘‘bulk’’ under the American Innovation and Manufacturing Act of 2020 (AIM) regulations at 40 CFR part 84.
- Revising the definition of ‘‘greenhouse gas or GHG’’ to clarify the treatment of fluorinated greenhouse gases by removing the partial list of fluorinated GHGs currently included in the definition and to simply refer to the definition of ‘‘fluorinated greenhouse gas (GHG).’’
- Adding the acronym ‘‘(GHGs)’’ after the term ‘‘fluorinated greenhouse gas’’ both in the definition of ‘‘greenhouse gas or GHG’’ and in the definition of ‘‘fluorinated greenhouse gas’’ to avoid redundancy and potential confusion between the definitions of ‘‘greenhouse gas’’ and ‘‘fluorinated greenhouse gas.’’
- Consistent with the revisions of the fluorinated GHG groups used to assign default GWPs discussed in section III.A.1.a. of this preamble, adding a definition of ‘‘cyclic’’ as it applies to molecular structures of various fluorinated GHGs; adding definitions of ‘‘unsaturated chlorofluorocarbons (CFCs),’’ ‘‘saturated chlorofluorocarbons (CFCs),’’ ‘‘unsaturated bromofluorocarbons (BFCs),’’ ‘‘unsaturated bromochlorofluorocarbons (BCFCs),’’ ‘‘unsaturated hydrobromofluorocarbons (HBFCs),’’ and ‘‘unsaturated hydrobromochlorofluorocarbons (HBCFCs)’’; and revising the definition of ‘‘fluorinated greenhouse (GHG) group’’ to include the new and revised groups.
- Revising the term ‘‘other fluorinated GHGs’’ to ‘‘remaining fluorinated GHGs’’ and to revise the definition of the term to reflect the new and revised fluorinated GHG groups discussed in section III.A.1.a. of this preamble.
- Revising the definition of ‘‘fluorinated heat transfer fluids’’ and moving it from 40 CFR 98.98 to 98.6 to harmonize with changes to subpart OO of part 98 (Suppliers of Industrial Greenhouse Gases) (see section III.U. of this preamble). The revised definition (1) explicitly includes industries other than electronics manufacturing, and (2) excludes most HFCs which are widely used as heat transfer fluids outside of electronics manufacturing and are regulated under the AIM regulations at 40 CFR part 84.
- Consistent with final revisions to subpart PP (Suppliers of Carbon Dioxide) (see section III.V. of this preamble), we are finalizing revisions to 40 CFR 98.6 to add a definition for ‘‘Direct air capture’’ and to amend the definition of ‘‘Carbon dioxide stream.’’

The EPA is making one revision to the definitions in the final rule from proposed to correct the definition of ‘‘ASTM’’. This change updates the definition to include the current name of the standards organization, ‘‘ASTM, International’’.

Consistent with final revisions to subparts Q (Iron and Steel Production), VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916), WW (Coke Calciners), and XX (Calcium Carbide Production), we are finalizing revisions to 40 CFR

98.7 to incorporate by reference ASTM International (ASTM) E415–17, *Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry* (2017) (subpart Q); CSA/ANSI ISO 27916:19, *Carbon dioxide capture, transportation and geological storage—Carbon dioxide storage using enhanced oil recovery* (CO_2–EOR) (2019) (subpart VV) (as proposed in the 2023 Supplemental Proposal); ASTM D3176–15 *Standard Practice for Ultimate Analysis of Coal and Coke* (2015), ASTM D5291–16 *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants* (2016), ASTM D5373–21 *Standard Test Methods for Determination of Carbon, Hydrogen, and Nitrogen in Analysis Samples of Coal and Carbon in Analysis Samples of Coal and Coke* (2021), and NIST HB 44–2023: *Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices,* 2023 edition (subpart WW); and ASTM D5373–08 *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal* (2008) and ASTM C25–06, *Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime* (2006) (subpart XX). The EPA has revised the regulatory text of 40 CFR 98.7 from proposal to incorporate these revisions and to reorganize the existing referenced ASTM standards in alphanumeric order.

The EPA is not finalizing proposed amendments to subpart A from the 2022 Data Quality Improvements Proposal that correlate with proposed amendments to subpart W of part 98 (Petroleum and Natural Gas Systems) from the 2022 Data Quality Improvements Proposal in this action. As noted in section I.C. of this preamble, the EPA has issued a subsequent proposed rule for subpart W on August 1, 2023, and has reproposed related amendments to subpart A in that action. Additionally, the EPA is not taking final action at this time on proposed amendments to subpart A from the 2023 Supplemental Proposal that were proposed harmonizing revisions intended to integrate proposed subpart B (Energy Consumption), including proposed reporting and recordkeeping under 40 CFR 98.2(a)(1), 98.3(c)(4), and 98.3(g)(5). Finally, we are not taking final action, at this time, on proposed amendments to 40 CFR 98.7 to incorporate by reference standards for electric metering. As discussed in section III.B. of this document, the EPA is not taking final action on subpart B at this time.

c. Revisions To Streamline and Improve Implementation for Subpart A

The EPA is finalizing several revisions to subpart A proposed in the 2022 Data Quality Improvements Proposal that will streamline and improve implementation for part 98. First, we are revising tables A–3 and table A–4 to subpart A to revise the applicability of subparts DD (Electrical Transmission and Distribution Equipment Use) and SS (Electrical Equipment Manufacture of Refurbishment) of part 98 as proposed. For subpart DD, the final revisions to table A–3 change the threshold such that facilities must account for the total estimated emissions from F–GHGs, as determined under 40 CFR 98.301 (subpart DD), for comparison to a threshold equivalent to 25,000 mtCO_2e or more per year. We are also moving subpart SS from table A–3 to table A–4 to subpart A and specifying that subpart SS facilities must account for emissions of F–GHGs, as determined under the requirements of 40 CFR 98.451 (subpart SS), for comparison to a threshold equivalent to 25,000 mtCO_2e or more per year. The final rule updates the threshold of subparts DD and SS to be consistent with the threshold set for the majority of subparts under part 98, and accounts for additional fluorinated gases (including F–GHG mixtures) reported by industry. For subpart DD, these final changes also focus Agency resources on the substantial emission sources within the sector by excluding facilities or operations that may report emissions that are consistently and substantially below 25,000 mtCO_2e per year. See sections III.Q. and III.Y. of this preamble for additional information.

2. Summary of Comments and Responses on Subpart A

This section summarizes the major comments and responses related to the proposed amendments to subpart A. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart A.

a. Comments on Revisions To Global Warming Potentials

Comment: Several commenters supported the proposed revisions to table A–1 to subpart A to update the GWP values to use values from table 8.A.1 from the IPCC AR5, and for certain GHGs without GWP values listed in AR5, to adopt values from the IPCC AR6. Commenters remarked that the updates to the GWP values will be more accurate, align with UNFCCC guidance and the Inventory, and provide consistency to reporters who may also report under various voluntary standards, such as the GHG Protocol or Sustainability Accounting Standards Board.

Some commenters requested that the EPA clarify the effects of changing the GWP (particularly for CH_4) on the reported total CO_2e emissions, despite any actual change in mass emissions. The commenters asserted that it is important to inform stakeholders that future increases in CO_2e emissions due to the change in GWP are not reflective of any actual mass emission increases and may obscure decreases in annual mass emissions. The commenters also recommended that the EPA acknowledge how combustion CO_2e emissions will be affected.

Response: In the final rule, the EPA is finalizing its proposal (in the 2023 Supplemental Proposal) to adopt the 100-year GWPs from AR5, and for certain GHGs without GWPs listed in AR5, to adopt values from AR6. Regarding the commenters' concern that the change in GWPs may result in apparent, but not real, upward or downward trends in the data, the EPA has always published emissions using consistent GWPs for every year and will continue to do so. Prior to publication, the EPA updates all reported CO_2e values to reflect the current GWP values in table A–1 to subpart A of part 98. The CO_2e published by the EPA are based on the same GWP values across all reporting years. Hence, there will be no apparent upward or downward trend in emissions that are due only to a change in a GWP value.

Comment: A number of commenters supported the continued use of a 100-year GWP; one commenter stated that the 100-year GWP is consistent with Article 2 of the UNFCCC and that any movement to a framework that reduces the mitigation focus on CO_2 emissions and adds to long-term warming potential compared to the 100-year GWP framework would not be well justified. Several commenters specifically commented on the proposed GWP for CH_4; a number of commenters generally supported revising the CH_4 GWP value from 25 to 28 using the 100-year GWP. Other commenters recommended that the EPA consider incorporating GWP values on multiple time horizons in the reporting requirement, or when publicizing reported emissions. One commenter stated that the 100-year GWP does not capture the near-term potency of short-lived gases like methane and hydrogen and is insufficient to reflect a pollutant's warming power over time. Commenters requested that the EPA incorporate the use of additional time horizons, such as the 20-year GWP, to acknowledge the near-term warming potency of short-lived gases such as CH_4, because they play a critical role in driving the rate of warming for the near future. Commenters argued that the 20-year GWP more accurately represents the powerful, short-term impact of methane on the atmosphere. Commenters noted that this would also align with several state regulatory programs, including California, New York, and New Jersey, that currently consider 20-year GWPs. Commenters stressed that adopting short-lived climate pollutant strategies and emissions controls to limit near-term warming is critical from a policy perspective and directly relevant to the EPA's efforts under the Clean Air Act. Commenters also requested that historic inventories be updated to reflect the role that short-lived climate pollutants play and to demonstrate that near-term CH_4 emissions reductions are as important as long-term CO_2 reductions.

Response: As has been the case since the inception of the GHGRP, we are finalizing 100-year GWPs for all GHGs. As noted in the ''Response to Comments on Final Rule, Volume 3: General Monitoring Approach, the Need for Detailed Reporting, and Other General Rationale Comments'' (see Docket ID. No. EPA–HQ–OAR–2008–0508–2260), the EPA selected the 100-year GWPs because these values are the internationally accepted standard for reporting GHG emissions. For example, the parties to the UNFCCC agreed to use GWPs that are based on a 100-year time period for preparing national inventories, and the reports submitted by other signatories to the UNFCCC use GWPs based on a 100-year time period, including the GWP for CH_4 and certain GHGs identified as short-lived climate pollutants. These values were subsequently adopted and used in multiple EPA climate initiatives, including the EPA's Significant New Alternatives Policy (SNAP) program and the Inventory, as well as EPA voluntary reduction partnerships (*e.g.,* Natural Gas STAR). Human-influenced climate change occurs on both short (decadal) and long (millennial) time scales. While there is no single best way to value both short- and long-term impacts in a single metric, the 100-year GWP is a reasonable approach that has been widely accepted by the international community. If the EPA were to adopt a 20-year GWP solely for CH_4, or for certain other compounds, it would introduce a metric that is inconsistent with both the GWPs used for the remaining table A–1 gases and with the reporting guidelines issued by the UNFCCC and used by the Inventory and other EPA programs. Additionally, the EPA and other Federal agencies, which calculate the impact of short-lived GHGs using 100-year GWPs, are making reduction of short-lived GHGs a priority, such as through the U.S. Global Methane Initiative. In addition, it is beneficial for both regulatory agencies and industry to use the same GWP values for these GHG compounds because it allows for more efficient review of data collected through the GHGRP and other U.S. climate programs, reduces potential errors that may arise when comparing multiple data sets or converting GHG emissions or supply based on separate GWPs, and reduces the burden for reporters and agencies to keep track of separate GWPs. For the reasons described above, the EPA is retaining a 100-year time horizon as the standard metric for defining GWPs in the GHGRP.

b. Comments on Other Revisions To Improve the Quality of Data Collected for Subpart A

Comment: Several commenters opposed the EPA's proposed revisions to 40 CFR 98.3(h)(4) to limit the total number of days a reporter can request to extend the time period for resolving a substantive error, either by submitting a revised report or providing information demonstrating that the previously submitted report does not contain the substantive error, to 180 days. Commenters requested that the Agency not put an inflexible cap on the number of days to resolve reporting issues; the commenters asserted that the extensions can be helpful for newly affected sources, when there is a change in facility ownership, and in other situations. One commenter stated that the proposed revision may result in arbitrarily short time-periods in which an operator may correct an error, especially in cases where the correction may not be accepted. The commenter contended that the EPA must add additional language to clarify that the 180-day limit will restart if the correction is not accepted. Commenters also requested that the EPA increase the limit of the total number of days a reporter can request an extension beyond the proposed 180 days to provide reporters more time to work through the new provisions in the program. One commenter requested the EPA restart the 180-day extension request opportunity for each instance in which an operator is notified of a substantive error or rejected correction (*e.g.,* if a correction is rejected, if additional corrections are requested, if corrections span more than one reporting year, or if EPA responses to operator questions are delayed).

Response: The EPA expects that 180 days is a reasonable amount of time for a facility to examine company records, gather additional data, and/or perform recalculations to submit a revised report or provide the necessary information such that the report may be verified. This represents more than four 30-day additional extensions beyond the initial 45-day period. As noted in the preamble to the final rule promulgated on October 30, 2009 (74 FR 52620, hereafter referred to as the ''2009 Final Rule''), the EPA concluded that this initial 45-day period would be sufficient since facilities have three months from the end of a reporting period to submit the initial annual report and have already collected and retained data needed for the analyses, so revisions to address a known error would likely require less time (see 74 FR 56278). A subsequent series of extensions of up to an additional 135 days is a reasonable amount of time to accommodate any additional changes that may be needed to the revision.

B. Subpart B—Energy Consumption

The EPA is not taking final action on the proposed addition of subpart B of part 98 (Energy Consumption) in this final rule. The EPA received a number of comments for proposed subpart B. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to proposed subpart B.

In the 2022 Data Quality Improvements Proposal, the EPA requested comment on collecting data on energy consumption in order to improve the quality of the data collected under the GHGRP. Specifically, we provided background on the EPA's original request for comment on the collection of data related to electricity consumption in the development of part 98 and the EPA's response in the 2009 Final Rule, and requested comment on whether and how the EPA should collect energy consumption data in order to support data analyses related to informing voluntary energy efficiency programs, provide information on industrial sectors where currently little data are reported to GHGRP, and inform quality assurance/quality control (QA/QC) of the Inventory. We requested comment on specific considerations for the potential addition of the energy consumption source category (see section IV.F. of the preamble to the 2022 Data Quality Improvements Proposal for additional information).

Following consideration of comments received in response to the EPA's request for comment, we subsequently proposed, in the 2023 Supplemental Proposal, the addition of subpart B to part 98. At that time, we reiterated our interest in collecting data on energy consumption to gain an improved understanding of the energy intensity (*i.e.,* the amount of energy required to produce a given level of product or activity, both through on-site energy produced from fuel combustion and purchased energy) of specific facilities or sectors, and to better inform our understanding of energy needs and the potential indirect GHG emissions associated with certain sectors. The proposed rule included specific monitoring and reporting requirements for direct emitting facilities that report under part 98 and purchase metered electricity or metered thermal energy products. In the proposed rule, the EPA outlined a source category definition, rationale for the proposed applicability of the subpart to direct emitting facilities in lieu of a threshold, and specific monitoring, missing data, recordkeeping, and reporting requirements. The EPA did not propose requirements for facilities to calculate or report indirect emissions estimates associated with purchased metered electricity or metered thermal energy products. Additional information on the proposed amendments is available in the preamble to the 2023 Supplemental Proposal.

In response to the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal, the EPA received many comments on the proposed subpart from a variety of stakeholders providing input on the definition, applicability criteria, monitoring, reporting, recordkeeping, and additional requirements of the source category, as proposed, as well as a number of comments on the EPA's authority to collect the energy consumption data proposed under subpart B. The EPA is not taking final action on proposed subpart B at this time. The EPA intends to further review and consider these comments and other relevant information and may consider any next steps on the collection of data related to energy consumption in a future rulemaking. Therefore, none of the proposed requirements related to subpart B are included in this final rule. The EPA is also not taking final action on related amendments to subpart A (General Provisions) of part 98 that were proposed harmonizing changes for the implementation subpart B, including reporting requirements, as discussed in section III.A.1.b. of this preamble.

C. Subpart C—General Stationary Fuel Combustion

The EPA is finalizing several amendments to subpart C of part 98 (General Stationary Fuel Combustion) as proposed. In some cases, we are finalizing the proposed amendments with revisions. In other cases, we are not taking final action on the proposed amendments. Section III.C.1. of this preamble discusses the final revisions to subpart C. The EPA received several comments on the proposed subpart C revisions which are discussed in section III.C.2. of this preamble. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the final revisions to subpart C, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart C

This section summarizes the final amendments to subpart C. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart C can be found in this section and section III.C.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Revisions To Improve the Quality of Data Collected for Subpart C

The EPA is finalizing several revisions to improve the quality of data collected for subpart C. First, the EPA is finalizing modifications to the Tier 3 calculation methodology, including revisions to 40 CFR 98.33(a)(3)(iii) to provide new equations C–5A and C–5B, as proposed. The updated equations provide for calculating a weighted annual average carbon content and a weighted annual average molecular weight, respectively, and correct the calculation method for Tier 3 gaseous fuels. The new equations incorporate the molar volume conversion factor at standard conditions (as defined at 40 CFR 98.6) and, for annual average carbon content, the measured molecular weight of the fuel, in order to convert the fuel flow to the appropriate units of measure. The final rule includes corrections to the proposed paragraph references included in the definition of the variable ''MW'' (*i.e.,* molecular weight) to equation C–5.

The EPA is also finalizing as proposed revisions to provisions pertaining to the calculation of biogenic emissions from tire combustion. These revisions include:

- Removing the additional provision in 40 CFR 98.33(b)(1)(vii) on how to apply the threshold to only municipal solid waste (MSW) fuel when MSW and tires are both combusted and the reporter elects not to separately calculate and report biogenic CO_2 emissions from the combustion of tires, since biogenic CO_2 emissions from tire combustion must now be calculated and reported in all cases;
- Removing the language in 40 CFR 98.33(e) and 98.36(e)(2)(xi) referring to optional biogenic CO_2 emissions reporting from tire combustion;
- Removing the restriction in 40 CFR 98.33(e)(3)(iv) that the default factor that is used to determine biogenic CO_2 emissions may only be used to estimate the annual biogenic CO_2 emissions from the combustion of tires if the combustion of tires represents ''no more than 10 percent annual heat input to a unit'';
- Revising 40 CFR 98.33(e)(3)(iv)(A) so that total annual CO_2 emissions will be calculated using the applicable methodology in 40 CFR 98.33(a)(1) through (3) for units using Tier 1 through 3 for purposes of 40 CFR 98.33(a), and using the Tier 1 calculation methodology in 40 CFR 98.33(a)(1) for units using the Tier 4 or part 75 calculation methodologies for purposes of 40 CFR 98.33(a), when determining the biogenic component of MSW and/or tires under 40 CFR 98.33(e)(3)(iv);
- Revising 40 CFR 98.33(e)(3)(iv)(B) to update the default factor that is used to determine biogenic CO_2 emissions from the combustion of tires from 0.20 to 0.24; and
- Correcting 40 CFR 98.34(d) to reference 40 CFR 98.33(e)(3)(iv) instead of 40 CFR 98.33(b)(1)(vi) and (vii) and correcting 40 CFR 98.33(e)(1) to delete the parenthetical clause ''(except MSW and tires).''

These final revisions will update the default factor to be based on more recent data collected on the average composition of natural rubber in tires, remove potentially confusing or conflicting requirements, and result in a more accurate characterization of biogenic emissions from these sources.

See section III.B.1. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these revisions and their supporting basis. The EPA is also finalizing one additional revision related to the estimation of biogenic emissions after consideration of comments received on the 2022 Data Quality Improvements Proposal. Commenters requested that the EPA expand the monitoring requirements at 40 CFR 98.34(e) to include all combined biomass and fossil fuels and to allow for testing at one source when a common fuel is combusted. The EPA agrees that testing one emission source is reasonable when multiple combustion units are fed from a common fuel source. Accordingly, the EPA is revising 40 CFR 98.34(e) to allow for quarterly ASTM D6866–16 and ASTM D7459–08 testing of one representative unit for a common fuel source for all combined biomass (or fuels with a biomass component) and fossil fuels. See section III.C.2. of this preamble for additional information on related comments and the EPA's response.

We are finalizing corrections to the variable ''R'' in equation C–11. The term ''R'' is currently defined as ''The number of moles of CO_2 released upon capture of one mole of the acid gas species being removed (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2)'' and is being amended to ''The number of moles of CO_2 released per mole of sorbent used (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2).'' We are finalizing amendments to 40 CFR 98.33(c)(6)(i), (ii), (ii)(A), and (iii)(C), and to remove and reserve 40 CFR 98.33(c)(6)(iii)(B) (to clarify the methods used to calculate CH_4 and N_2O emissions for blended fuels when heat input is determined after the fuels are mixed and combusted), as proposed.

The EPA identified one additional minor correction to subpart C in review of changes for the final rule. Subsequently, we are correcting the definition of the term emission factor ''EF'' in equation C–10 from ''Fuel-specific emission factor for CH_4 or N_2O, from table C–2 of this section'' to ''Fuel-specific emission factor for CH_4 or N_2O, from table C–2 to this subpart.''

The EPA is finalizing as proposed two additional clarifications to the reporting and recordkeeping requirements. We are revising the first sentence of 40 CFR 98.36(e)(2)(ii)(C) to clarify that both the annual average, and where applicable, monthly high heat values are required to be reported. This change clarifies that the annual average high heat value is also a reporting requirement (for reporters who do not use the electronic inputs verification tool (IVT) within the e-GGRT). We are finalizing revisions to the 40 CFR 98.37(b) introductory paragraph and paragraphs (b)(9) through (11), (14), (18), (20), (22), and (23) to specify recordkeeping data that is currently contained in the file generated by the verification software that is already required to be retained by reporters under 40 CFR 98.37(b). These revisions correct omissions that currently exist in the verification software recordkeeping requirements specific to equations C–2a, C–2b, C–3, C–4, and C–5. They also align the verification software recordkeeping requirements with the final revisions to equation C–5 at 40 CFR 98.33(a)(3)(iii).

In the 2022 Data Quality Improvements Proposal, we proposed additional reporting requirements, for each unit greater than or equal to 10 mmBtu/hour in either an aggregation of units or common pipe configuration. The proposed reporting included, for each individual unit with maximum rated heat input capacity greater than or equal to 10 mmBtu/hour included in the group, the unit type, maximum rated heat input capacity, and an estimate of the fraction of the total group annual heat input attributable to each unit (proposed 40 CFR 98.36(c)(1)(ii) and (c)(3)(xi)). Following consideration of public comments, the EPA is not taking final action on the proposed reporting requirements (*i.e.,* identifying the unit type, maximum rated heat input capacity, and fraction of the total annual heat input for each unit in the aggregation of unit or common pipe). See section III.C.2. of this preamble for a summary of the related comments and the EPA's response.

In the 2023 Supplemental Proposal, the EPA proposed to add a requirement to report whether the unit is an EGU for each configuration that reports emissions, under either the individual unit provisions at 40 CFR 98.36(b)(12) or the multi-unit provisions at 40 CFR 98.36(c)(1)(xii), (c)(2)(xii), and (c)(3)(xii). For multi-unit reporting configurations, we also proposed adding a requirement for facilities to report an estimated decimal fraction of total emissions from the group that are attributable to EGU(s) included in the group. Following consideration of public comments, the EPA is not taking final action on the proposed revisions to the reporting requirements in this rule. See section III.C.2. of this preamble for a summary of the related comments and the EPA's response.

The EPA is also not taking final action in this final rule on proposed revisions to subpart C correlated with proposed amendments to subpart W (Petroleum and Natural Gas Systems). As noted in section I.C. of this preamble, the EPA has issued a subsequent proposed rule for subpart W on August 1, 2023 and has reproposed related amendments to subpart C in that separate action.

b. Revisions To Streamline and Improve Implementation for Subpart C

The EPA is finalizing all revisions to streamline and improvement implementation for subpart C as proposed. Specifically, the EPA is finalizing (1) amendments to 40 CFR 98.34(c)(6) to allow cylinder gas audits (CGAs) to be performed using calibration gas concentrations of 40–60 percent and 80–100 percent of CO_2 span, whenever the required CO_2 span value for a flue gas does is not appropriate for the prescribed audit ranges in appendix F of 40 CFR part 60; and (2) amendments to provisions in 40 CFR 98.36(c)(1)(vi) and 98.36(c)(3)(vi) to remove language requiring that facilities with the aggregation of units or common pipe configuration types report the total annual CO_2 mass emissions from all fossil fuels combined. See section III.B.2. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these changes and their supporting basis.

2. Summary of Comments and Responses on Subpart C

This section summarizes the major comments and responses related to the proposed amendments to subpart C. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart C.

Comment: One commenter provided a correction to the proposed revisions to equation C–5 related to the revisions to the Tier 3 calculation methodology. The commenter noted that the proposed revisions to variable ''MW'' of equation C–5 which specify the procedures to be used to determine the annual average molecular weight included an incorrect reference to paragraphs (a)(3)(iii)(A)(3) and (4), and should point to (a)(3)(iii)(B)(1) and (2).

Response: We agree that the proposal inadvertently contained incorrect cross-references for the variable ''MW'' of equation C–5, and the EPA has corrected these cross-references in the final rule.

Comment: Commenters generally supported the EPA's proposed revisions to update the calculation methodology for biogenic emissions from tire combustion. One commenter requested that the EPA consider expanding the requirements of 40 CFR 98.34(e), which requires quarterly testing to determine biogenic CO_2 when biomass and non-biogenic fuels are co-fired in a unit. The commenter noted that 40 CFR 98.34(e) currently allows for testing of a single representative unit for facilities with multiple units in which tires are the primary fuel combusted and the units are fed from a common fuel source. The commenter noted that for facilities with multiple units combusting the same fuel, testing each source quarterly imposes an additional burden without enhancing the accuracy of reported emissions. The commenter requested that the EPA expand the provisions to include all combined biomass and fossil fuels and to allow for testing one representative unit when fuel from a common fuel source is combusted.

Response: The EPA acknowledges the commenter's support for the proposed revisions. The EPA agrees with the commenter that testing one emission source when multiple emission sources are fed from a common fuel source should be allowed for all combined biomass (or fuels with a biomass component) and fossil fuels. Accordingly, the EPA has finalized quarterly ASTM D6866–16 and ASTM D7459–08 testing of one representative unit for multiple units fed from a common fuel source, for all combined biomass (or fuels with a biomass component) and fossil fuels.

Comment: Some commenters supported the EPA's proposal to revise 40 CFR 98.36(c)(1) and (3) to require reporting of additional information for each unit in either an aggregation of units or common pipe configuration (excluding units with maximum rated heat input capacity less than 10 mmBtu/hour), including the unit type, maximum rated heat input capacity, and an estimate of the fraction of the total annual heat input to the unit. These commenters agreed that unit-specific data is necessary to understand both the distribution of emissions across unit types and sizes, but also the abatement potential through various decarbonization strategies (*e.g.,* certain abatement strategies may be better suited for certain unit types and uses). The commenters stated that the requested data could assist the EPA in the development of NSPS or EG under CAA section 111. The commenters noted that, given the prevalence of reporting using combined configurations, this data would fill large data gaps in the current characterization of industrial sectors. One commenter asserted that the requirement should be extended to facilities that report using the common stack configuration or the alternative part 75 configuration, which would ensure that all emissions under the subpart are similarly affected by the proposed revisions and would provide a full picture of the GHG abatement potential of various source categories. Commenters also requested the EPA consider lowering or eliminate the size threshold below 10 mmBtu/hour; the commenter stated that although smaller units do not account for a large share of total capacity, they often present the most viable opportunities for greenhouse gas emissions abatement such as electrification with heat pump technology.

Other commenters opposed the proposed requirements. Opposing commenters stated that the EPA's explanation for collecting the data was ambiguous and did not sufficiently explain what data gaps are missing or how the collection of the additional information would resolve issues within the currently collected data. One commenter opposed disaggregating total emissions from the grouped combustion equipment, asserting that aggregating the emissions by individual equipment (excluding units rated less than 10 mmBtu/hour) using estimation techniques would not provide useful information. Several commenters asserted that the proposed approach could not reliably provide accurate estimates of actual heat input and is likely not to be technically feasible. For example, one commenter stated that the physical configuration of certain lime plants would preclude accurate unit-specific estimates of actual heat input, as the facilities lack certified calibrated meters on a kiln-by-kiln basis and rely on quantifying solid fuel usage based on surveys of on-site stockpiles. The commenter added that facility-wide reporting of combustion emissions satisfies the EPA's objective of developing facility-wide emissions information, and additional unit-level information is superfluous and of limited value. Other commenters stated that individual fuel meters are not common, asserting that annual heat input for individual units is often estimated based on the maximum high heat input rating and operating hours. One commenter stated that the heat input records maintained by facilities do not necessarily correspond to the actual heat input of a unit, especially for industries that use batching with different process equipment for different products. That commenter asserted that actual heat input may vary based on age of the unit; how it is utilized in processes for steam, cooling, or other purposes; and the high heating value of fuel during certain operating periods. Another commenter questioned whether the estimation technique proposed would likely undermine the reported data or compromise the integrity of actual values that are currently reported. Commenters asserted that the requirements would have potentially very limited value and may detract from the GHG emission estimates that regulated facilities produce for the EPA or other proposed Federal rules.

Commenters also expressed that the proposed requirements would be overly burdensome and significantly increase the recordkeeping and reporting burden. One commenter specifically referred to the requirement for facilities to estimate the total annual input of each unit expressed as a decimal fraction based on the actual heat input of each unit compared to the whole; the commenter stated that this requirement would essentially negate the time efficiencies gained by reporting the aggregated group, especially for reporters using the common pipe configuration. The commenter stated that this would essentially require that heat inputs be calculated for each piece of equipment each year and could result in a ten-fold increase in burden for reporters using the common pipe method. Commenters urged that the maximum rated heat input of each unit in the aggregated group and operating hours should provide enough information for the EPA to reasonably approximate emissions for individual equipment.

Response: Upon careful consideration, the EPA has decided not to take final action on the proposed reporting requirements for each unit greater than or equal to 10 mmBtu/hour in either an aggregation of units or common pipe configuration (the unit type, maximum rated heat input capacity, and an estimate of the fraction of the total annual heat input attributable to each unit in the group) (proposed 40 CFR 98.36(c)(1)(ii) and (c)(3)(xi)) at this time. We note that the EPA disagrees that estimating the fraction of the actual total annual heat input for each unit in the group, based on company records, will be overly burdensome to reporters. ''Company records'' is defined in the existing part 98 regulations at 40 CFR 98.6 to mean, ''in reference to the amount of fuel consumed by a stationary combustion unit (or by a group of such units), a complete record of the methods used, the measurements made, and the calculations performed to quantify fuel usage. Company records may include, but are not limited to, direct measurements of fuel consumption by gravimetric or volumetric means, tank drop measurements, and calculated values of fuel usage obtained by measuring auxiliary parameters such as steam generation or unit operating hours. Fuel billing records obtained from the fuel supplier qualify as company records.'' The broad definition of company records would afford reporters considerable flexibility when it comes to estimating the fraction of the actual total annual heat input for each unit in the group. The EPA may consider such reporting requirements in future rulemakings.

Comment: Two commenters stated that EGUs should not be reported under subpart C and are already reported under subpart D (Electricity Generation); one commenter asserted that it is unclear from the proposal how reporting these emissions under subpart C would not be duplicative. One of the two commenters additionally stated that EGUs are not specifically defined in subparts A or C of part 98, and that the EPA should provide clarification on the definition of EGUs. The commenter added that the proposed requirement would impose burden and regulatory confusion because of the conflicting definitions in, and applicability of, other EPA regulatory programs which traditionally have regulated EGUs separately from non-EGU combustion sources. The commenter stated that 40 CFR 98.36(f) already requires sources to identify if they are tied to an entity regulated by any public utility commission.

Another commenter suggested a definition for EGUs that aligns with a footnote to table A–7 to subpart A that defines EGUs for sources reporting under subpart C as ''a fuel-fired electric generator owned or operated by an entity that is subject to regulation of customer billing rates by the public utilities commission (excluding generators connected to combustion units subject to 40 CFR part 98, subpart D) and that are located at a facility for which the sum of the nameplate capacities for all such electric generators is greater than or equal to 1 megawatt electric output.''

One commenter requested clarification that waste heat generation is not included; the commenter added that requiring facilities to report emissions from the generation of electricity using waste heat recovery would be double counting. Other commenters requested clarification that emergency generators are exempt from the proposed requirements.

Two commenters supported the EPA's proposed requirement to allow operators to use an engineering estimate of the percentage of combustion emissions attributable to facility electricity generation. However, another commenter disagreed, stating that the EPA did not describe how a reporter would identify such a fraction. The commenter added that the EPA failed to take into account that emissions from a single combustion unit might provide steam to multiple consumers for multiple purposes, only a portion of which includes on-site electricity generation. The commenter expressed concerns that, if the rule is finalized as proposed, the methods to determine electricity-related emissions by fraction could become subject to numerous other requirements, such as calculations for GHG emissions, monitoring and QA/QC requirements, data reporting, and record retention obligations.

Response: The EPA is not taking final action on the proposed addition of a new indicator that would identify units as electricity generating units at this time. Furthermore, the EPA is not taking final action on the additional requirement for reporting an estimate of a group's total reported emissions attributable to electricity generation at this time. As discussed in the preamble to the 2023 Supplemental Proposal, under the current subpart C reporting requirements, the EPA cannot currently determine the quantity of EGU emissions included in the reported total emissions for the subpart. Although some facilities currently indicate whether certain stationary fuel combustion sources are connected to a fuel-fired electric generator in 40 CFR 98.36(f), this requirement only captures a subset of subpart C EGU emissions. The EPA therefore intended the proposed reporting requirements to identify other EGUs reporting under subpart C in order to improve our understanding of subpart C EGU GHG emissions and the attribution of GHG emissions to the power plant sector. However, we agree with commenters that the proposed requirements could require additional burden not contemplated by the proposed rule. Specifically, as noted by commenters, we recognize that there could be scenarios in which a single combustion unit or group of units may provide steam for multiple purposes, only a portion of which includes on-site electricity generation. In this case, although a facility may know the quantity of electricity generated and could estimate the quantity of steam required to generate the electricity, determination of the portion of GHG emissions that are attributable to the combustion unit(s) producing the steam that is used in an on-site EGU (among other processes) would additionally require the estimation of the type and quantity of fuel used by each combustion unit for the purposes of producing the steam used to generate electricity. For this reason we are not taking final action on these requirements in this rule.

D. Subpart F—Aluminum Production

We are not taking final action on any proposed amendments to subpart F of part 98 (Aluminum Production) in this action. In the 2022 Data Quality Improvements Proposal, the EPA requested comment on several issues related to determining emissions from aluminum production. Specifically, the EPA requested information on the extent to which low voltage emissions have been characterized, if data are available to develop guidance on low voltage emission measurements, and on the use of the non-linear method as an alternative to the slope coefficient and overvoltage methods currently allowed in subpart F. The EPA received comments on these issues but is not taking final action on any changes to the measurement methodology for subpart F at this time.

In the 2023 Supplemental Proposal, the EPA proposed revisions to the reporting requirements at 40 CFR 98.66(a) and (g) to require that facilities report the facility's annual production capacity and annual days of operation for each potline. We noted at that time that the capacity of the facility and capacity utilization would provide useful information for understanding variations in annual emissions and emission trends across the sector. The EPA received several comments on the proposed subpart F revisions. Following consideration of comments received, we are not taking final action on the proposed revisions at this time. However, the EPA may consider similar changes to reporting requirements in a future rulemaking. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart F.

E. Subpart G—Ammonia Manufacturing

We are finalizing amendments to subpart G of part 98 (Ammonia Manufacturing) as proposed. In some cases, we are finalizing the proposed amendments with revisions. In other cases, we are not taking final action on the proposed amendments. This section discusses the final revisions to subpart G. The EPA received only supportive comments for the proposed revisions to subpart G. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart G. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

In the 2022 Data Quality Improvements Proposal, the EPA proposed several revisions to subpart G to require reporters to report the GHG emissions that occur directly from the ammonia manufacturing process (*i.e.,* net CO_2 process emissions) after subtracting out carbon or CO_2 captured and used in other products. The proposed revisions included combining equation G–4 and equation G–5 into a new equation G–4 and several harmonizing revisions to 40 CFR 98.72(a); revisions to the introductory paragraph of 40 CFR 98.73; the removal of § 98.73(b)(5); revisions to the introductory paragraph of 40 CFR 98.76; and revisions to the reported data elements at 40 CFR 98.76(b)(1) and (13), as described in section III.C. of the preamble to the 2022 Data Quality Improvements Proposal.

The EPA is finalizing minor edits to 40 CFR 98.72(a), the introductory paragraph of 40 CFR 98.73, the introductory paragraph to 40 CFR 98.76, and 40 CFR 98.76(b)(1) to clarify the term ''ammonia manufacturing unit,'' as well as clarifying edits to 40 CFR 98.76(b)(13) to clearly identify any CO_2 used in the production of urea and carbon bound in methanol that is intentionally produced as a desired product. Additionally, we are finalizing clarifying amendments to equation G–1, equation G–2, and equation G–3 to simplify the equations by removing the process unit ''k'' designation in the terms ''$CO_{2,G,k}$,'' ''$CO_{2,L,k}$,'' and ''$CO_{2,S,k}$.'' We are also finalizing the removal of § 98.73(b)(5) and equation G–5, consistent with our intent at proposal to require reporting of emissions by ammonia manufacturing unit.

Following consideration of comments received on similar changes proposed for subpart S (Lime Manufacturing), the EPA is not taking final action at this time on the proposed revisions to allow facilities to subtract out carbon or CO_2 captured and used in other products. We have revised new equation G–4 in the final rule to remove the proposed equation terms related to CO_2 collected and consumed on-site for urea production and the mass of methanol intentionally produced as a desired product, and removed text related to ''net'' CO_2 process emissions. The EPA is also not taking final action at this time on the addition of related monthly recordkeeping data elements that were proposed as verification software records. See section III.K.2. of this preamble for a summary of related comments and the EPA's response.

We are finalizing as proposed one amendment to subpart G from the 2023 Supplemental Proposal to include a requirement for facilities to report the annual quantity of excess hydrogen produced that is not consumed through the production of ammonia at 40 CFR 98.76(b)(16). This is a harmonizing change to ensure that the final revisions to subpart P (Hydrogen Production) to exclude reporting from any process unit for which emissions are reported under another subpart of part 98, including ammonia production units that report emissions under subpart G (see section III.I. of this preamble), will not result in the exclusion of reporting of any excess hydrogen production at facilities that are subject to subpart G.

We are also finalizing as proposed related confidentiality determinations for data elements resulting from the revisions to subpart G, as described in section VI. of this preamble.

F. Subpart H—Cement Production

We are finalizing several amendments to subpart H of part 98 (Cement Production) as proposed. In some cases, we are finalizing the proposed amendments with revisions. Section III.F.1. of this preamble discusses the final revisions to subpart H. The EPA received several comments on the proposed subpart H revisions which are discussed in section III.F.2. of this preamble. We are also finalizing confidentiality determinations for new data elements resulting from the revisions to subpart H, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart H

This section summarizes the final amendments to subpart H. Major changes in this final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart H can be found in this section and section III.F.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal.

The EPA is finalizing several revisions to improve the quality of data collected for subpart H. First, we are finalizing the addition of several new data reporting elements to subpart H under 40 CFR 98.86(a) and (b) to enhance the quality and accuracy of the data collected. In the 2022 Data Quality Improvements Proposal, the EPA proposed to add several data reporting elements based on annual average chemical composition data for facilities using either the direct measurement (using a continuous emission monitoring system (CEMS)) methodology or the mass balance methodology, in order to assist in improving verification of reported data. The proposed data elements included (for both facilities that report CEMS data and those that report using a mass balance method) the annual arithmetic average weight fraction of: the total calcium oxide (CaO) content, non-calcined CaO content, total magnesium oxide (MgO) content, and non-calcined MgO content of clinker at the facility (proposed 40 CFR 98.86(a)(4) through (a)(7) and (b)(19) through (b)(22)); and the total CaO content of cement kiln dust (CKD) not recycled to the kiln(s), non-calcined CaO content of CKD not recycled to the kiln(s), total MgO content of CKD not recycled to the kiln(s), and non-calcined MgO content of CKD not recycled to the kiln(s) at the facility (proposed 40 CFR 98.86(a)(8) through (11) and (b)(23) through (26)). The EPA also proposed to collect other data (from both facilities using CEMS and those that report using the mass balance method), including annual facility CKD not recycled to the kiln(s) in tons (proposed 40 CFR 98.86(a)(12) and (b)(27)) and raw kiln feed consumed annually at the facility in tons (dry basis) (proposed 40 CFR 98.86(a)(13) and (b)(28)), for both verification and to improve the methodologies of the Inventory.

The EPA is finalizing the proposed requirements to report the annual arithmetic average weight fraction of the total CaO content, non-calcined CaO content, total MgO content, and non-calcined MgO content of clinker at the facility (proposed 40 CFR 98.86(a)(4) through (7) and (b)(19) through (22)), and the annual facility CKD not recycled to the kiln(s) (proposed 40 CFR 98.86(a)(12) and (b)(27), finalized as 40 CFR 98.86(a)(8) and (b)(27), respectively), for both facilities that use CEMS and those that report using the mass balance method. We are also finalizing, for facilities using the mass balance method, the total CaO content of CKD not recycled to the kiln(s), non-calcined CaO content of CKD not recycled to the kiln(s), total MgO content of CKD not recycled to the kiln(s), and non-calcined MgO content of CKD not recycled to the kiln(s) at the facility (proposed 40 CFR 98.86(b)(23) through (26)), and the amount of raw kiln feed consumed annually (proposed 40 CFR 98.86(b)(28)). Finalizing these data elements will improve the EPA's ability to verify reported emissions (*e.g.,* the EPA will be able to create a rough estimate of process emissions at the facility and compare that to the reported total emissions, and check whether the ratio is within expected ranges). For facilities using CEMS, the finalized data elements will enable the EPA to estimate process emissions from facilities to provide a more accurate national-level cement emissions profile and the Inventory. Following consideration of public comments, we are not taking final action on certain proposed data elements for facilities that report using CEMS. Specifically, the EPA is not taking final action on the proposed requirements to report the annual arithmetic average of the total CaO content of CKD not recycled to the kiln(s), non-calcined CaO content of CKD not recycled to the kiln(s), total MgO content of CKD not recycled to the kiln(s), and non-calcined MgO content of CKD not recycled to the kiln(s) at the facility (proposed 40 CFR 98.86(a)(8) through (11)). We are also not taking final action on the reporting of the amount of raw kiln feed consumed annually (proposed 40 CFR 98.86(a)(13)). See section III.F.2. of this preamble for a summary of the related comments and the EPA's response.

The EPA is finalizing as proposed several clarifications and corrections to equations H–1, H–4, and H–5 included in the 2022 Data Quality Improvements Proposal. The final revisions to equation H–1 add brackets to clarify the summation of clinker and raw material emissions for each kiln, and update the definition of parameter ''$CO_{2\ rm}$'' to ''$CO_{2\ rm,m}$'' and clarify the raw material input is on a per-kiln basis. The final revisions to equation H–5 revise the inputs ''rm,'' ''$CO_{2\ rm}$'' (revised to ''$CO_{2\ rm,m}$''), and ''TOC_{rm},'' and add brackets to clarify that emissions are calculated as the sum of emissions from all raw materials or raw kiln feed used in the kiln. The final revisions to equation H–4 correct the defined parameters for the quarterly non-calcined CaO content and the quarterly non-calcined MgO content of CKD not recycled to ''CKD_{ncCaO}'' and ''CKD_{ncMgO},'' respectively, to align with the parameters defined in the equation.

2. Summary of Comments and Responses on Subpart H

This section summarizes the major comments and responses related to the proposed amendments to subpart H. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart H.

Comment: One commenter objected to the EPA's proposed addition of data reporting requirements for facilities reporting using the CEMS methodology. The commenter asserted that the new data requirements would add unnecessary burden without providing additional insight into cement industry GHG emissions or improving the quality or accuracy of the emissions data provided. The commenter stated that, under the new provisions, the EPA would essentially be requiring kilns that are currently using CEMS to report their emissions to verify their data by using the mass balance method, with associated reporting and recordkeeping. The commenter noted that CEMS are already required to meet extensive quality assurance and quality control requirements and have been determined as the most accurate means of measuring stack emissions. Further, the commenter reasoned that the EPA can accurately determine process emissions using already reported data, total kiln stack emissions data, and combustion emissions data, which they stated is included in the confidential monthly clinker production data and fuel use data provided using the Tier 4 methodology in subpart C. The commenter stated that it is well established by the scientific community that process emissions represent 60 percent of CO_2 emissions from the kiln based on the standard chemistry of the cement manufacturing process, and that the currently reported data should be sufficient.

The commenter also opposed the EPA's proposed data reporting elements for facilities using the mass balance (non-CEMS) methodology, likewise insisting that the EPA can readily determine both process and combustion emissions from the existing reporting requirements. The commenter explained that (1) the reporting of total and non-calcined CaO and MgO is irrelevant to calculating CO_2 process emissions as they are inherently non-carbonate; and (2) in reference to the proposed CKD reporting requirement, calculating the CKD not recycled and the quantity of raw kiln feed at all kilns within a facility would add burden without providing any additional information about industry GHG emissions. The commenter also questioned the need for the additional data, stating that the EPA did not provide an explanation of how the additional data would be used separately from potentially verifying process emissions. The commenter also expressed concern that the addition of these data elements would justify regulatory overreach from other programs.

Response: We disagree with the commenter's statement that reporting additional data from facilities using CEMS will not enhance the EPA's verification of the facility reported values. The EPA has encountered occasional instances of mistakes in reported CEMS data (*e.g.,* from data entry mistakes), resulting in significant errors in reported emissions. Fuel use data are not provided to the EPA for cement plants that report emissions using CEMS. Currently, fuel use data are entered into the IVT to calculate CH_4 and N_2O emissions from combustion for kilns with CEMS, as the process and combustion emissions are both vented through the same stack. These IVT data are not directly reported to the EPA, so the EPA cannot use them to verify the accuracy of reported emissions.

Furthermore, we are not persuaded by the commenter's assertion that process emissions represent 60 percent of kiln emissions. Cement kilns can have very different process and combustion emissions depending on the input materials, the fuel or energy source used, etc., and an average process emissions factor would not be representative of all facilities in subpart H. Furthermore, the commenter does not provide additional information about how this statistic was calculated and whether it is representative of cement manufacturing plants in the United States. The commenter did not specify where this statistic can be found in the cited source (''Getting the Numbers Right Database, Global Cement and Concrete Association'' [9]) and did not provide the underlying data to the EPA for review. Importantly, this database contains information on global cement production, and emissions profiles at facilities in the United States can differ widely from those in other countries due to differences in input

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[9] Available at *https://gccassociation.org/sustainability-innovation/gnr-gcca-in-numbers/.* Accessed January 9, 2024.

materials, fuels used, and emission control systems that may be in place. The EPA has reviewed data, such as those from the UNFCCC, which suggest that implied emissions rates may vary from 49–57 percent and change by country.[10]

Upon careful review and consideration, the EPA has decided not to adopt the proposed changes to require the chemical composition data for CKD and amount of raw kiln feed consumed annually for facilities reporting with CEMS (proposed 40 CFR 98.86(a)(8) through (11) and (a)(13)). We are not taking final action on these elements after consideration of the comments and in an effort to reduce potential burden. The EPA is finalizing the remaining proposed reporting requirements as these data elements will improve verification of reported emissions. For example, the EPA will be able to create a rough estimate of process emissions at the facility and compare that to the reported total emissions, and check whether the ratio is within expected ranges. We will also be able to build evidence-based verification checks on the clinker composition data that is entered by facilities that do not use CEMS (we currently have very little information on what chemical compositions are typical in cement kilns). The final reporting elements will also enable the EPA to estimate process emissions from CEMS facilities to provide a more accurate national-level emissions profile for the cement industry and the Inventory. Reporting average chemical composition data for the clinker is expected to be less burdensome for facilities, as this data is likely collected as a part of normal business operations, while collection of CKD data may be less common. Furthermore, we do not believe these additional data elements constitute regulatory overreach as they are similar to other data already collected under subpart H and will be important for verification and our understanding of process and combustion emissions.

We also disagree that collecting additional data from facilities using the mass balance method will not enhance the EPA's verification of the facility reported values. Currently clinker composition data are entered into the IVT and are not included in the annual report that is submitted to the EPA. Reporting of these and additional data elements will improve verification of reported emissions and the mass balance calculations (*e.g.,* by allowing us to create evidence-based verification checks for clinker composition data). The final reporting elements will also provide a more accurate national-level emissions profile for the cement industry and the Inventory. With respect to the burden associated with these added reporting elements for reporters using the mass balance reporting method, these data elements are the annual arithmetic averages of either monthly or quarterly data elements that these reporters already input into e-GGRT through the IVT. These data elements are currently entered into the IVT and used for equations H–2 through H–5; but they are not reported to the EPA. Thus, the burden, if any, is expected to be minimal. There are no changes, as compared to the proposal, to the final reporting requirements for facilities using the mass balance methodology after consideration of this comment.

G. Subpart I—Electronics Manufacturing

We are finalizing several amendments to subpart I of part 98 (Electronics Manufacturing) as proposed. In some cases, we are finalizing the proposed amendments with revisions. In other cases, we are not taking final action on the proposed amendments. Section III.G.1. of this preamble discusses the final revisions to subpart I. The EPA received several comments on the proposed subpart I revisions which are discussed in section III.G.2. of this preamble. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the revisions to subpart I as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart I

This section summarizes the final amendments to subpart I. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart I can be found in this section and section III.G.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Revisions To Improve the Quality of Data Collected for Subpart I

In the 2022 Data Quality Improvements Proposal, the EPA proposed several revisions to subpart I to improve data quality, including revising the stack testing calculation method, updating the calculation methods used to estimate emission factors in the technology assessment report, updating existing default emission factors and destruction or removal efficiencies (DREs) based on new data, adding a calculation method for calculating byproducts produced in abatement systems, amending data reporting requirements, and providing clarification on reporting requirements. In the 2023 Supplemental Proposal, the EPA subsequently proposed corrections to specific revisions from the 2022 Data Quality Improvements Proposal, including DRE values in table I–16 and gamma factors in proposed new table I–18 to subpart I of part 98.

The EPA is finalizing several revisions to 40 CFR 98.93(i) to improve the calculation methodology for stack testing. These revisions include:

- Adding new equations I–24C and I–24D and a table of default weighting factors (new table I–18) to calculate the fraction of fluorinated input gases exhausted from tools with abatement systems, $a_{i,f}$, for use in equations I–19A through I–19C and I–21, and the fraction of byproducts exhausted from tools with abatement systems, $a_{k,i,f}$, for use in equations I–20 and I–22.
- Revising equations I–24A and I–24B, which calculate the weighted average DREs for individual F–GHGs across process types in each fab.
- Revising 40 CFR 98.93(i)(3) to require that all stacks be tested if the stack test method is used.
- Replacing equation I–19 with a set of equations (*i.e.,* equations I–19A, I–19B, and I–19C) that will more accurately account for emissions when pre-control emissions of an F–GHG come close to or exceed the consumption of that F–GHG during the stack testing period.
- Clarifying the definitions of the variables d_{if} and d_{kif}, the average DREs for input gases and byproduct gases respectively, in equations I–19A, I–19B, I–19C, and I–19D, in equations I–20 through I–22, in equations I–24A and B, and in equation I–28 to subpart I.

These revisions will remove the current requirements to apportion gas consumption to different process types, to manufacturing tools equipped versus not equipped with abatement systems, and to tested versus untested stacks. Equations I–24C and I–24D add the option to calculate the fraction of each input gas ''i'' and byproduct gas ''k'' exhausted from tools with abatement systems based on the number of tools that are equipped versus not equipped with abatement systems, along with weighting factors that account for the

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[10] United Nations Framework Convention on Climate Change. (2023). National inventory submissions 2023. *https://unfccc.int/ghg-inventories-annex-i-parties/2023.*

different per-tool emission rates that apply to different process types. The weighting factors ($\gamma_{i,p}$ for input gases and $\gamma_{k,i,p}$ for byproduct gases, provided in table I–18) are based on data submitted by semiconductor manufacturers during the process of developing the 2019 Refinement (as corrected in the 2023 Supplemental Proposal). We are finalizing revisions to equations I–24A and I–24B, used to calculate the average DRE for each input gas "i" and byproduct gas "k," based on tool counts and the same weighting factors that will be used in equations I–24C and I–24D; this accounts for operations in which a facility uses one or more abatement systems with a certified DRE value that is different from the default to calculate and report controlled emissions. We are finalizing the requirement that all stack systems be tested by removing 40 CFR 98.93(i)(1); this removes not only the need to apportion gas usage to tested versus untested stack systems, but also the requirement to perform a preliminary calculation of the emissions from each stack system. We are finalizing new equations I–19A, I–19B, and I–19C, with a clarification, which will more accurately account for emissions when emissions of an F–GHG prior to entering any abatement system (*i.e.,* pre-control emissions) would approach or exceed the consumption of that F–GHG during the stack testing period. We are clarifying that the 0.8 maximum for the 1–U value only applies to carbon-containing F–GHGs. As discussed in the proposal, the modification to the stack testing method was intended to accurately account for the source of emissions when the measured emissions exceed the consumption of the F–GHG during the stack testing period, which may occur in situations where the input gas is also generated in significant quantities as a by-product by the other input gases. However, it is not expected that NF_3 or SF_6 could be generated as a by-product by a fluorocarbon used as an input gas. Therefore, this modification is not appropriate and was not intended to apply to SF_6 or NF_3 emissions when calculating emissions using the stack test method. The revised equations improve upon the current equations because they account both for any control of the emissions and for some utilization of the input gas. Finally, we are finalizing revisions to the definitions of the variables d_{if} and d_{kif} in equations I–19A, I–19B, I–19C, and I– 19D, in equations I–20 through I–22, in equations I–24A and B, and in equation I–28 to clarify that these variables reflect the fraction of gas i (or byproduct gas k) that is destroyed once gas i (or byproduct gas k) is fed into abatement systems. See section III.E.1.a. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these revisions and their supporting basis.

With some changes, the EPA is finalizing revisions to improve the quality of the data submitted in the technology assessment reports in 40 CFR 98.96(y) as proposed in the 2022 Data Quality Improvements Proposal. Specifically, the EPA proposed to require that reporters who submit a technology assessment report would use three methods (the "all-input gas method," the "dominant gas method," and the "reference emission factor method") to report the results of each emissions test to estimate utilization and byproduct formation emission rates. The EPA is finalizing a requirement to report the results using two of the three methods proposed, including the all-input gas method, with a clarification, and the reference emission factor method, and is allowing use of a third method of the reporter's choice, as follows:

- All-input gas method. For input gas emission rates, this method attributes all emissions of each F–GHG that is an input gas to the input gas emission factor (1–U) factor for that gas, if the input gas does not contain carbon or until that 1–U factor reaches 0.8 if the input gas does contain carbon, after which emissions of the F–GHG are attributed to the other input gases. For byproduct formation rates, this method attributes emissions of F–GHG byproducts that are not also input gases to all F–GHG input gases (kilogram (kg) of byproduct emitted/kg of all F–GHGs used).
- Reference emission factor method. This method estimates emissions using the 1–U and the byproduct formation rates that are observed in single gas recipes and then adjusts both emission factors based on the ratio between the emissions calculated based on the factors and the emissions actually observed in the multi-gas process.
- The EPA is finalizing an option for reporters to use, in addition to the utilization and byproduct formation rates calculated according to the required all-input gas method and the reference emission factor method, an alternative method of their choice to calculate and report the utilization or byproduct formation rates based on the collected data.

These revisions will ensure that the emission factors submitted in the technology assessment reports are robust (for example, not unduly affected by changing ratios of input gases) and are comparable to each other and to the emission factors already in the EPA's database. The EPA proposed, and is finalizing with a clarification, modifications to the all-input gas method to avoid an input gas emission factor greater than 0.1 when multiple gases are used. The modified method uses 0.8 as the maximum 1–U value, and as such, attributes emissions of each F–GHG used as an input gas to that input gas until the mass emitted equals 80 percent of the mass fed into the process (*i.e.,* until the 1–U factor equals 0.8). The all-input gas method assigns the remaining emissions of the F–GHG to the other input gases as a byproduct in proportion to the quantity of each input gas used in the process. We are finalizing this modified method with the clarification that the 0.8 maximum for the 1–U value only applies to carbon-containing F–GHGs. As discussed in the proposal, the modification to the all-input method was intended to avoid the situations where the historical methods would violate the conservation of mass or fail to reflect the fact that some fraction of the input gas reacts with the film it is being used to etch or clean, which may occur in situations where the input gas is also generated in significant quantities as a by-product by the other input gases. However, it is not expected that NF_3 or SF_6 could be generated as a by-product by a fluorocarbon used as an input gas. Therefore, this modification is not appropriate and was not intended to apply to SF_6 or NF_3 emissions when calculating emission factors. The EPA is requiring use of the all-input gas method to facilitate comparisons of new data to historical data; the all-input gas method was the most commonly used method in the submitted data sets included in technology assessment reports from 2013 and earlier. Following consideration of comments received and to reduce burden, the EPA is not taking final action on the proposed requirement to report emission factors using the dominant gas method. The dominant gas method calculates 1–U factors in the same way as the all-input gas method, but it calculates byproduct formation rates differently, attributing all emissions of F–GHG byproducts to the carbon-containing F–GHG input gas accounting for the largest share by mass of the input gases. Additional information on each of the three methods is available in section III.E.1.b. of the preamble to the 2022 Data Quality Improvements Proposal and in the memorandum "Technical Support for Modifications to the Fluorinated

Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I,'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424. As noted in the proposed rule, the EPA intends to make available a calculation workbook for the technology assessment report that will calculate the two sets of emission factors based on each of the final methods using a single set of data entered by the reporter. The option to calculate the emission factors using an additional method provides flexibility for reporters while enabling comparison between the results of the additional method and the results of the two required methods. Where reporters choose to submit emission factors using the additional method, we will be able to evaluate the reliability and robustness of emission factors calculated using all three methods. Additional information on comments related to the calculation methods and the EPA's response can be found in section III.G.2.a. of this preamble.

The EPA is also finalizing two additional requirements for the submitted technology assessment reports including requiring reporters to specify (1) the method used to calculate the reported utilization and byproduct formation rates and assign and provide an identifying record number for each data set; and (2) for any DRE data submitted, whether the abatement system used for the measurement is specifically designed to abate the gas measured under the operating condition used for the measurement. For reporters who opt to additionally provide utilization and byproduct formation rates using an alternative method of their choice, reporters must provide this information and a description of the alternative method used.

The EPA is finalizing revisions to update the default emission factors and DREs in subpart I based on new data submitted as part of the 2017 and 2020 technology assessment reports and the 2019 Refinement, as proposed in the 2022 Data Quality Improvements Proposal and corrected in the 2023 Supplemental Proposal. These revisions include:

- Updates to the utilization rates and byproduct emission factors (BEFs) for F–GHGs used in semiconductor manufacturing in tables I–3, I–4, I–11 and I–12;
- Removal of byproduct emission factors from tables I–3 and I–4 where there is a combination of both a low BEF and a low GWP resulting in very low reported emissions per metric ton of input gas used (removes the BEF for C_4F_6 and C_5F_8 for all input gases used in wafer cleaning or plasma etching processes, and results in not adding BEFs for COF_2 and C_2F_4 for any input gas/process combination from the new data submitted as part of the 2017 and 2020 technology assessment reports).
- In cases where neither the input gas nor the films being processed in the tool contain carbon, setting the BEF for the carbon-containing byproducts to zero. These provisions apply at the process subtype level. For example, a BEF of zero will only be used for a combination of input gas and chamber cleaning process subtype (*e.g.,* NF_3 in remote plasma cleaning (RPC)) if no carbon-containing materials were removed using that combination of input gas and chamber cleaning process subtype during the year and no carbon-containing input gases were used on those tools. Otherwise, the default BEF will be used for that combination of input gas and chamber cleaning process subtype for all of that gas consumed for that subtype in the fab for the year. The EPA is making one modification to the proposed equation to clarify that the carbon-containing byproduct emission factors are zero when the combination of input gas and etching and wafer cleaning process type uses only non-carbon containing input gases (SF_6, NF_3, F_2 or other non-carbon input gases) and etches or cleans only films that do not contain carbon.
- Updates to the default emission factors for N_2O used in all electronics manufacturing in table I–8, including distinct utilization rates for semiconductor manufacturing and LCD manufacturing and, for semiconductor manufacturing, utilization rates by wafer size;
- Revisions to the calculation methodology for MEMS and PV manufacturing to allow use of 40 CFR 98.93(a)(1), the current methodology for semiconductor manufacturing, for manufacture of MEMS and PV using semiconductor tools and processes, which applies the default emission factors in tables I–3 and I–4 to these processes;
- Revisions to 40 CFR 98.93(a)(6) to revise the utilization rate and byproduct emission factor values assigned to gas/process combinations where no default utilization rate is available; these revisions account for the likely partial conversion of the input gas into CF_4 and C_2F_6. The final rule requires, for a gas/process combination where no default input gas emission factor is available in tables I–3, I–4, I–5, I–6, and I–7, reporters will use an input gas emission factor (1–U) equal to 0.8 (*i.e.,* a default utilization rate or U equal to 0.2) with BEFs of 0.15 for CF_4 and 0.05 for C_2F_6.
- Revisions to the default DREs in table I–16 to subpart I to reflect new data and strengthening of abatement system certification requirements. The final revisions assign chemical-specific DREs to all commonly used F–GHGs for the semiconductor manufacturing sub-sector without distinguishing between process types.

Additional information on the EPA's derivation of the final emission factors and DREs is available in section III.E.1.c. of the preamble to the 2022 Data Quality Improvements Proposal and in the revised technical support document, ''Revised Technical Support for Revisions to Subpart I: Electronics Manufacturing,'' available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2019–0424).

The EPA is also finalizing revisions to the conditions under which the default DRE may be claimed, with some revisions from the proposal so that the new documentation requirements apply only to abatement systems purchased and installed on or after January 1, 2025. For all abatement systems for which a DRE is being claimed, including abatement systems purchased and installed during or after 2025 and older abatement systems, the EPA is maintaining the current certification and documentation requirements and is finalizing the proposed additional requirement that the certification must contain a manufacturer-verified DRE value. If the abatement system is certified to abate the F–GHG or N_2O at a value equal to or higher than the default DRE, the facility may claim the default DRE. If the abatement system is certified to abate the F–GHG or N_2O but at a value lower than the default DRE, the facility may not claim the default; however, the facility may claim the lower manufacturer-verified value. (Site-specific measurements by the electronics manufacturer are still required to claim a DRE higher than the default.) Based on annual reports submitted through RY2022, facilities have historically been able to provide manufacturer-verified DRE values for all abatement systems for which emission reductions have been claimed.

Additional requirements apply to abatement systems purchased and installed on or after January 1, 2025. Specifically, the EPA is finalizing revisions to the definition of operational mode in 40 CFR 98.98 to specify that for abatement systems purchased and installed during or after January 1, 2025, operational mode means that the system is operated within the range of parameters as specified in the DRE certification documentation. The specified parameters must include the highest total F–GHG or N_2O flows and highest total gas flows (with N_2 dilution accounted for) through the emissions control systems. Systems operated outside the range of parameters specified in the documentation supporting the DRE certification may rely on a measured site-specific DRE according to 40 CFR 98.94(f)(4) to be considered operational within the range of parameters used to develop a site-specific DRE.

The EPA is also finalizing revisions to 40 CFR 98.94(f)(3) to modify the conditions under which the default or lower DRE may be claimed for abatement systems purchased and installed on or after January 1, 2025. For systems purchased and installed on or after January 1, 2025, reporters are required to: (1) certify that the abatement device is able to achieve, under the worst-case flow conditions during which the facility is claiming that the system is in operational mode, a DRE equal to or greater than either the default DRE value, or if the DRE claimed is lower than the default DRE value, a manufacturer-verified DRE equal to or greater than the DRE claimed; and (2) provide supporting documentation. Specifically, for POU abatement devices purchased and installed on or after January 1, 2025, reporters must certify and document under 40 CFR 98.94(f)(3)(i) and (ii) that the abatement system has been tested by the abatement system manufacturer using a scientifically sound, industry-accepted measurement methodology that accounts for dilution through the abatement system, such as EPA 430–R–10–003,[11] and that the system has been verified to meet (or exceed) the destruction or removal efficiency used for that fluorinated GHG or N_2O under worst-case flow conditions (the highest total F–GHG or N_2O flows and highest total gas flows, with N_2 dilution accounted for). Because manufacturers routinely conduct DRE testing and are familiar with the protocols of EPA 430–R–10–003, we anticipate this information will be readily available for abatement systems purchased in calendar year 2025 or later. The EPA is finalizing that the new DRE requirements will be implemented for reports prepared for RY2025 and submitted March 31, 2026, which provides over a year for reporters to acquire the necessary documentation. Reporters are not required to maintain documentation of the DRE on abatement systems for which a DRE is not being claimed.

We are also clarifying that the list of abatement system manufacturer specifications within which the abatement system must be operated at 40 CFR 98.96(q)(2) is intended to be exemplary, adding ''which may include, for example,'' before the list. This clarifies that some of the listed specifications or parameters may not be specified by all abatement system manufacturers for all abatement systems, and leaves open the possibility that some abatement system manufacturers may include other specifications within which the abatement system must be operated.

Additionally, following consideration of comments received, we are clarifying how reporters account for uptime of the abatement device if suitable backup emissions control equipment or interlocking with the process tool is implemented for each emissions control system. The EPA is revising the definition of the term ''UT_{ij}'' in equation I–15 and the definition of ''UT_f'' in equation I–23 to clarify that if all the abatement systems for the relevant input gas and process type are interlocked with all the tools feeding them, the uptime may be set to one (1). We are also clarifying equations I–15 and I–23 to reference the provisions in 40 CFR 98.94(f)(4)(vi) when accounting for uptime when redundant abatement systems are used. See section III.G.2.a. of this preamble for additional information on related comments and the EPA's response.

The EPA is finalizing the addition of a calculation methodology that estimates the emissions of CF_4 produced in hydrocarbon-fuel based combustion emissions control systems (''HC fuel CECs'') that are not certified not to generate CF_4. Following consideration of public comments, the calculation will be required only for HC fuel CECs purchased and installed on or after January 1, 2025. To implement the new calculation methodology, we are adding a new equation I–9 and renumbering the previous equation I–9 as equation I–8B. Equation I–9 only applies to processes that use F_2 as an input gas or to remote plasma cleaning processes that use NF_3 as an input gas. Equation I–9 estimates the emissions of CF_4 from generation in emissions control systems by calculating the mass of the fluorine entering uncertified HC fuel CECs (the product of the consumption of the input gas, the emission factor for fluorine, and a_i, where a_i is the ratio of the number of tools with uncertified abatement devices for the gas-process combination to the total number of process tools for the gas-process combination) and multiplying that mass by a CF_4 emission factor, $AB_{CF4,F2}$, which has a value of 0.116. In related changes, the EPA is finalizing a BEF for F_2 from NF_3 used in remote plasma clean processes of 0.5. For other gas and process combinations where no data are available (listed as ''NA'' in tables I–3 and I–4), the EPA is finalizing a BEF of 0.8 be used for F_2 in equation I–9 for all process types.

The EPA is requiring that reporters estimate CF_4 emissions from all HC fuel CECs that are purchased and installed on or after January 1, 2025 and that are not certified not to produce CF_4, even if reporters are not claiming DREs for those systems. However, as noted above, the requirements apply only to HC fuel CECs used on processes that use F_2 as an input gas or to remote plasma cleaning processes that use NF_3 as an input gas. We are also finalizing a related definition of ''hydrocarbon-fuel-based combustion emissions control system (HC fuel CECS),'' which we have revised from the proposed ''hydrocarbon-fuel-based emissions control system,'' to align with the 2019 Refinement and to clarify that the term includes systems used on processes that have the potential to emit F_2 or fluorinated GHGs, as recommended by commenters. As noted above, we have also revised the final rule from proposal to require these estimates from HC fuel CECS purchased and installed on or after January 1, 2025. We are also finalizing corresponding monitoring, reporting, and recordkeeping requirements (see 40 CFR 98.94(e), 40 CFR 98.96(o), and 40 CFR 98.97(b), respectively) for facilities that use HC fuel CECS purchased and installed during or after 2025 to control emissions from tools that use either NF_3 as an input gas in RPC processes or F_2 as an input gas in any process and assume in equation I–9 that one or more of those systems do not form CF_4 from F_2. Under these requirements facilities must certify and document that the model for each of the systems that the facility assumes does not form CF_4 from F_2 has been tested and verified to produce less than 0.1 percent CF_4 from F_2, and that each of these systems is installed, operated, and maintained in accordance with the directions of the HC fuel CECS manufacturer. The facility may perform the testing itself, or it may supply documentation from the HC fuel CECS manufacturer that supports the certification. Because the requirement to quantify emissions of CF_4 from F_2 is being applied only to HC fuel CECS purchased and installed on or after

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[11] Protocol for Measuring Destruction or Removal Efficiency of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing, Version 1, March 2010 (''EPA DRE Protocol''), as incorporated at 40 CFR 98.7.

January 1, 2025, we anticipate that most HC fuel CECS will be tested by the HC fuel CECS manufacturer. If the facility performs the testing, it is required to measure the rate of conversion from F_2 to CF_4 using a scientifically sound, industry-accepted method that accounts for dilution through the abatement device, such as the EPA DRE Protocol, adjusted to calculate the rate of conversion from F_2 to CF_4 rather than the DRE.

The EPA is also finalizing related amendments to 40 CFR 98.94(j)(1)(i) to require that the uptime (*i.e.,* the fraction of time that abatement system is operational and maintained according to the site maintenance plan for abatement systems) during the stack testing period average at least 90 percent for uncertified HC fuel CECS. Following consideration of comments received, we are clarifying in the final rule that these provisions are limited to only those HC fuel CECS that were purchased and installed on or after January 1, 2025, that are used to control emissions from tools that use either NF_3 in remote plasma cleaning processes or F_2 as an input gas in any process type or sub-type, and that are not certified not to form CF_4. See section III.G.2.a. of this preamble for additional information on related comments on HC fuel CECS and the EPA's response.

Finally, the EPA is not taking final action on proposed revisions to the calibration requirements for abatement systems. In the 2022 Data Quality Improvements Proposal, the EPA proposed that a vacuum pump's purge flow indicators are calibrated every time a vacuum pump is serviced or exchanged, with the expectation that this requirement would require calibrations every one to six months, depending on the process. Following review of input provided by commenters, we are not taking final action on the proposed revisions. Removal of the proposed requirements is anticipated to reduce the potential burden on reporters without any large effects on data quality. Section III.G.2.a. of this preamble provides additional information on the comments received related to vacuum pump purge flow calibration and the EPA's response.

b. Revisions To Streamline and Improve Implementation for Subpart I

In the 2022 Data Quality Improvements Proposal, the EPA proposed several revisions intended to streamline the calculation, monitoring, or reporting in specific provisions in subpart I to provide flexibility or increase the efficiency of data collection. The EPA is finalizing these changes as proposed. First, the final rule revises the applicability of subpart I as follows:

- Adds a second option in 40 CFR 98.91(a)(1) and (2) for estimating GHG emissions for semiconductor, MEMS, and LCD manufacturers, for comparison to the 25,000 $mtCO_2e$ per year emissions threshold in 40 CFR 98.2(a)(2), that is based on gas consumption in lieu of production capacity. The revisions include new equations I–1B and I–2B to multiply gas consumption by a simple set of emission factors, the gas GWPs, and a factor to account for heat transfer fluid to estimate emissions. The emission factors are included in new table I–2 to subpart I of part 98 and are the same as the emission factors for gas and process combinations for which there is no default in tables I–3, I–4, or I–5 to subpart I. Facilities that choose to use this option for their calculation method will be required to track annual gas consumption by GHG but are not required to apportion consumption by process type for the purposes of assessing rule applicability.
- Revises the current applicability calculation for PV manufacturers to revise equation I–3 and refer to new table I–2, and delete the phrase "that have listed GWP values in table A–1," to increase the accuracy of the estimated emissions for determining applicability; and
- Updates the emission factors in table I–1 to subpart I of part 98 used in the current applicability calculations for MEMS and LCD manufacturers based on new Tier 1 emission factors in the 2019 Refinement.

Additional information on the EPA's revisions to applicability and the final emission factors is available in section III.E.2.a. of the preamble to the 2022 Data Quality Improvements Proposal.

The EPA additionally proposed, and is finalizing, to revise the frequency and applicability of the technology assessment report requirements in 40 CFR 98.96(y), which applies to semiconductor manufacturing facilities with GHG emissions from subpart I processes greater than 40,000 $mtCO_2e$ per year. First, we are finalizing amendments to 40 CFR 98.96(y) to decrease the frequency of submission of the reports from every three years to every five years. As we noted in the preamble to the 2022 Data Quality Improvements Proposal, revising the frequency of submission to every five years will increase the likelihood that reports will include updates in technology rather than conclusions that technology has not changed. At the time of proposal, this would have moved the due date for the next technology assessment, from March 31, 2023, to March 31, 2025. Because the EPA is not implementing the revisions in this final rule until January 1, 2025, we have revised the provision in the final rule to clarify that the first technology assessment report due after January 1, 2025 is due on March 31, 2028. Section III.G.2.b. of this preamble provides additional information on the comments received related to the frequency of submittal of the technology assessment report and the EPA's response.

We are also finalizing revisions to restrict the reporting requirement in 40 CFR 98.96(y) to facilities that emitted greater than 40,000 $mtCO_2e$ and produced wafer sizes greater than 150 mm (*i.e.,* 200 mm or larger) during the period covered by the technology assessment report, as well as explicitly state that semiconductor manufacturing facilities that manufacture only 150 mm or smaller wafers are not required to prepare and submit a technology assessment report. The final provisions also clarify that a technology assessment report need not be submitted by a facility that has ceased (and has not resumed) semiconductor manufacturing before the last reporting year covered by the technology assessment report (*i.e.,* no manufacturing at the facility for the entirety of the year immediately before the year during which the technology assessment report is due).

2. Summary of Comments and Responses on Subpart I

This section summarizes the major comments and responses related to the proposed amendments to subpart I. See the document "Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule" in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart I.

a. Comments on Revisions To Improve the Quality of Data Collected for Subpart I

Comment: The EPA received several comments related to the proposed revisions to the stack testing calculation methodology in subpart I. Largely, commenters objected to the EPA's proposal that "all stacks" be tested. The commenters questioned the use of the terminology "all stacks" within the proposed preamble and disagreed with the EPA's assumption that the number of stacks at each fab is expected to be small (*e.g.,* one to two). The commenters provided input from an industry survey of 33 fabs, suggesting that over 250 stacks would require testing, as well as an additional 170 process stacks that do not contain F–GHGs (*e.g.,* general fab exhausts). The commenters urged that adding stacks that do not have the potential to emit F–GHGs to the stack testing scope would add an additional $60,000 to $200,000 per testing event and as much as $400,000 for large sites. The commenters requested the EPA clarify that the testing is required for all operating stacks or stack systems that have the potential to emit F–GHGs, and that the rule retain the current terminology of ''stack system.''

Response: Even though the EPA referred to ''all stacks'' in the proposal preamble, we agree that the testing is required only for all operating stack systems. The proposed and final regulatory text continue to use the term ''stack system,'' which is defined as ''one or more stacks that are connected by a common header or manifold, through which a fluorinated GHG-containing gas stream originating from one or more fab processes is, or has the potential to be, released to the atmosphere. For purposes of this subpart, stack systems do not include emergency vents or bypass stacks through which emissions are not usually vented under typical operating conditions.'' We are finalizing the proposed requirement that all stack systems must be tested in accordance with 40 CFR 98.93(i)(3)(ii).

Comment: The EPA received comments objecting to proposed revisions to the technology assessment report to require use of three proposed calculation methods (*i.e.,* the dominant input gas method, all-input gas method, and reference emission factor method) to develop utilization and byproduct emission factors. The commenters expressed that each of EPA's proposed methods fails to meet the agency's goals for consistent implementation of emission factors across facilities and to allow for comparability across the industry and in industry emission rates. Specifically, the commenters asserted that the dominant input gas method and all-input gas method violate the physical reality of conservation of mass for plasma etch/wafer cleaning processes when using multiple gases and may lead to byproduct emission factors greater than 1. The commenters continued that the dominant input gas method does not clearly define what gas would be dominant in situations where gases of equal or near-equal mass are used. For both of the all-input gas method and the dominant input gas method, the commenters criticized the use of a ''cap'' value of 0.8 as inconsistent with the agency's goal to calculate emission factors consistently with those already in the EPA's data set. For the all-input gas method, commenters added that the cap of 0.8 for individual testing does not align with the maximum seen within historical test data submitted by industry, but is instead aligned with the maximum average emission factor across all gases. Commenters stated that the modification to both methods may amplify or obfuscate technology changes by setting an artificial maximum emissions value.

The commenters also stated that it is unclear how the reference emission factor method would be implemented. Specifically, commenters questioned whether 1–U or the byproduct emission factors would be held constant, maintaining that the method increases the difficulty in comparing individual tests depending on what is held constant, and adding that if new gases or byproducts are used or measured, the methodology will not have a reference emission basis to apply. Commenters expressed that the additional burden and complexity of calculating technology emission factors three different ways could be a disincentive to facility testing and would not improve overall emissions accuracy.

The commenters requested that in lieu of the three calculation methods, the EPA consider use of the ''multi-gas method,'' which attributes all non-carbon-containing GHGs, such as SF_6 and NF_3, to the input of these non-carbon-containing GHGs and attributes all carbon-containing F–GHG emissions across all carbon-based input F–GHGs. The commenters believe that the multi-gas method would appropriately assign emissions (especially for recipes running more than two gases at once), would eliminate concerns regarding emission factors that do not meet conservation of mass principles, and is not reliant on past or assumed data to calculate emission factors or byproduct emission factors. Commenters explained that high variability in single-gas emission factors is due to a variety of factors, including the amount or concentration of input gases, as well as plasma and manufacturing tool variables, and suggested that use of the multi-gas method would generate emission factors consistent and within the range of the existing emission factor data, while also being able to accommodate new gases and changes in technology.

Response: The EPA disagrees with the commenter's assessment of the three proposed emission factor methods. We also disagree that the proposed requirements are overly burdensome. However, following consideration of the comments raised, we are revising the final rule to require reporters to estimate emission factors using two of the three proposed methods (the all-input gas method and the reference emission factor method) and to allow reporters to submit results using an additional method of their choice. As noted in the preamble to the proposed rule, we plan to provide a spreadsheet that will automatically perform the calculations for the two required methods using a single data set entered by the reporters, minimizing burden. As explained in both section III.E.1.b. to the preamble to the 2022 Data Quality Improvements proposal and the subpart I technical support document,[12] the all-input gas method is quite consistent with the historically used methods, differing from the historically used methods only under circumstances where the historically used methods are likely to yield unrealistic results (*e.g.,* where CF_4 is used as an input gas and accounts for a small fraction of the mass of all input gases, yielding CF_4 input gas emission factors over 0.8). Of the three methods proposed, the reference emission factor method is somewhat less consistent with the historically used methods, but is expected to be more robust in that its results are less affected by changing ratios of input gases. As discussed further below, both of these methods are more consistent with the historical methods and less affected by changing input gas ratios than the method favored by the commenter, the multi-gas method.

After consideration of comments, the EPA is not taking final action on the proposed requirement to report emission factors calculated using the dominant gas method for several reasons. First, the dominant gas method estimates the input gas emission rate in the same way as the all-input gas method, making it redundant with the all-input gas method for calculation of input gas emission rates. Second, the dominant gas method estimates the byproduct emission rate by assigning all emissions of F–GHG byproducts to the carbon-containing F–GHG input gas accounting for the largest share by mass of the input gases, which is anticipated, as noted by commenters, to be less accurate in cases where input gases of equal or near-equal mass are used. Third, in the historical data sets submitted to the EPA, the all-input gas method was the most commonly used

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[12] See document ''Technical Support for Proposed Revisions to Subpart I (2022),'' available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

method; therefore, retaining this approach rather than the dominant gas method will allow the EPA to more reliably compare the new data submitted to the historical data set. Finally, not requiring use of the dominant gas method will reduce burden on facilities that are required to submit technology assessment reports.

As noted in the preamble to the 2022 Data Quality Improvements proposal, receiving results based on multiple methods will enable the EPA: (1) to directly compare the new emission factor data to the emission factor data that are already in the EPA's database and that were calculated using the historical method; and (2) to compare the results across the available emission factor calculation methods and to identify any systematic differences in the results of the different methods for each gas and process type. By identifying and quantifying systematic differences in the results of the different methods, we will be better able to distinguish these differences from differences attributable to technology changes. Knowledge of these systematic differences will also be useful in the event that we ultimately require facilities to submit emission factors using one method only, particularly if that method is not closely related to one of the methods used historically. We will also be able to evaluate how much the results of each method vary for each gas and process type; high variability may indicate that the results of a method are being affected by varying input gas proportions rather than differences in gas behavior. On the other hand, extremely low variability may also indicate that a method is affected by input gas proportions. For example, if the all-input-gas method yields a large number of input gas emission factors equal to 0.8, the maximum allowed value for input gas emission factors under this method, this implies that some of the emissions being attributed to the input gas are actually being generated as byproducts from other input gases that are collectively more voluminous, conditions under which the reference emission factor method may yield the most reliable results. Ultimately, these analyses will enable us to more accurately characterize emissions from semiconductor manufacturing by selecting the most robust emission factor data for updating the default emission factors in tables I–3 and I–4. Note that the EPA would update the default emission factors using the rulemaking process, providing an opportunity for industry to comment on the data and methodology used to develop any proposed factors.

Regarding the comment that the proposed rule did not clarify how the reference emission factor would be implemented, including whether the 1–U or by-product emission factors would be adjusted, the proposed rule made it clear that both the 1–U and byproduct emission factors would be adjusted where the emitted gas was also an input gas. The preamble to the proposed rule stated, ''the reference emission factor method calculates emissions using the 1–U and the BEFs [by-product emission factors] that are observed in single gas recipes and then adjusts both factors based on the ratio between the emissions calculated based on the factors and the emissions actually observed in the multi-gas process. This approach uses all the information available on utilization and by-product generation rates from single-gas recipes while avoiding assumptions about which of these are changing in the multi-gas recipe'' (87 FR 36947). The proposed equations I–31A (for 1–U factors, finalized as equation I–30A) and I–31B (for by-product factors, finalized as equation I–30B) showed this in mathematical terms and also showed how the method would apply where more than two input gases were used. The proposed rule also clearly indicated that where a by-product gas was not also an input gas, proposed equation I–30B (finalized as equation I–29B) was to be used. Equation I–29B is the equation used in the all-input-gas method as well as the reference emission factor method for by-products that are not also input gases. Equation I–29B would apply to newly observed as well as previously observed by-product gases that were not also input gases.

This leaves only the situation where an input gas is used in a process type for the first time along with other input gases. While we expect that this situation will be rare, we agree that it should be addressed. We are clarifying in the final rule that where an input gas is used in a process type with other input gases and there is no 1–U factor for that input gas in table I–19 or I–20, as applicable, the Reference Emission Factor Method will not be used to estimate the emission factors for that process.

We are not specifying the multi-gas method as the sole method for calculating emission factors submitted in the technology assessment report. As noted in the proposed rule, one of the EPA's goals in collecting emission factor data through the technology assessment report is to better understand how emission factors may be changing as a result of technological changes in the semiconductor industry, and whether the changes to the emission factors may justify further data collection to comprehensively update the default emission factors in tables I–3 and I–4. To meet this goal, the emission factors submitted in the technology assessment reports should be calculated using methods that are similar to the methods used to calculate the emission factors already in the EPA's database; otherwise, differences attributable to differences in calculation methods may amplify or obscure differences attributable to technology changes. The multi-gas method assigns emissions of all carbon-containing F–GHGs to all carbon-containing F–GHG input gases, regardless of species, yielding input gas emission factors that are equal to byproduct gas formation factors for each emitted F–GHG. These input gas and byproduct gas emission factors are significantly different from the input gas and byproduct gas emission factors yielded by the historically used methods, making it difficult to discern the impact of technology changes as opposed to calculation method changes on the emission factors. In addition, our analysis indicated that the multi-gas method results are highly sensitive to the ratios of the masses of input gases fed into the process, which appears likely to affect the robustness and reliability of emission factors calculated using that method.[13] For these reasons, we have concluded that it would not be appropriate to require submission of emission factors using only the multi-gas method.

However, we are providing an option in the final rule for reporters to use, in addition to the required all-input gas method and the reference emission factor method, an alternative method of their choice to calculate and report updated utilization or byproduct formation rates based on the collected data. Reporters will therefore have the opportunity to provide emission factor data that are calculated using the multi-gas method or other methodologies, provided the reporter provides a complete, mathematical description of the alternative calculation method and labels the data calculated using that method consistent with the requirements for the all-input gas method and the reference emission factor method. Submitting emission factors calculated using the multi-gas

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[13] *Id.* The EPA has included in the docket a memo and spreadsheet showing the results of the different emission factor calculation methods using the same data (see Docket ID. No. EPA–HQ–OAR–2019–0424–0142, memorandum and attachment 3 Excel spreadsheet).

method along with the other two methods would allow us to compare the results of the multi-gas method to the results of the other two (one of which is very similar to the primary historically used method) and to identify any systematic differences. As noted above, by identifying and quantifying systematic differences in the results of the different methods, we will be better able to distinguish these differences from differences attributable to technology changes. We may also be able to relate the results of the historical methods to the results of methods that differ from those used historically. Receiving emission factors calculated using three methods would also allow us to better assess the robustness and reliability of the emission factors calculated using all three methods, *e.g.,* by seeing which methods yield highly variable emission factors within each input gas-process type combination. Because the final rule does not require reporters to submit emission factors calculated using an alternative methodology, the requirement to provide a complete, mathematical description of the alternative calculation method used is not anticipated to add significant burden.

Comment: Commenters supported the proposal to remove BEFs for C_4F_6 and C_5F_8 and the decision to not add COF_2 and C_2F_4, as byproduct emissions of them account for <<0.001% of overall GHG emissions from semiconductor manufacturing operations. One commenter also requested the EPA clarify that carbon-containing byproduct emission factors are zero when calculating emissions from non-carbon containing input gases (SF_6, NF_3, F_2, or other non-carbon input gases) and when the film being etched or cleaned does not contain carbon, as this would align the EPA final rule with the 2019 Refinement.

Response: The EPA is finalizing the rule as proposed to remove the BEFs for C_4F_6 and C_5F_8. The EPA is also not adding BEFs for COF_2 or C_2F_4. For non-carbon containing input gases used in cleaning processes, we proposed to set carbon-containing byproduct emission factors to zero when the combination of input gas and chamber cleaning process sub-type is never used to clean chamber walls on manufacturing tools that process carbon-containing films during the year (*e.g.,* when NF_3 is used in remote plasma cleaning processes to only clean chambers that never process carbon-containing films during the year). We agree with the commenter that non-carbon-containing input gases used in etching processes are similarly not expected to give rise to carbon-containing byproducts if neither the input gases nor the films being etched contain carbon. We are therefore finalizing an expanded version of the proposed provision, setting carbon-containing byproduct emission factors to zero for etching and wafer cleaning processes as well as chamber-cleaning processes when these conditions are met. The revisions align the rule requirements with the 2019 Refinement.

Comment: Commenters expressed several concerns regarding the EPA's proposed revisions to the conditions under which the default DRE may be claimed. One commenter requested the EPA remove the requirement to provide supporting documentation for all abatement units using certified default or lower than default DREs. The commenter also requested the EPA clarify that reporters are not required to maintain supporting documentation on abatement units for which a DRE is not being claimed.

Commenters also contended that the existing language in subpart I is sufficient to ensure proper point-of-use (POU) device performance while being consistent with the 2019 Refinement, and the requirement to provide supporting documentation of manufacturer certified POU DREs, including testing method, is burdensome and may be unachievable, especially for older abatement units. One commenter expressed concern that the proposed increase in certification and documentation requirements beyond existing POU operational requirements will dissuade semiconductor companies from accounting for DREs from installed POU, resulting in an over-estimate of emissions from the semiconductor industry. The commenter also stated that adding operational elements of fuel and oxidizer settings, fuel gas flows and pressures, fuel calorific values, and water quality, flow, and pressures to the POU DRE requirements are outside the manufacturer-specified requirements for emissions control and are not necessary to ensure accurate POU DREs. Commenters stated that abatement equipment installed across the industry does not have manufacturer specifications for all listed parameters, or the capability to track all listed parameters. Commenters concluded that these and other POU default DRE certification and documentation requirements go above and beyond the 2019 Refinement and will make it more difficult for U.S. reporters to take credit for installed and future emissions control devices, resulting in a less accurate, overestimated GHG emissions inventory. One commenter supported applying the requirements only to equipment purchased after the reporting rule becomes effective. The commenter stated that verification testing would be especially burdensome; the commenter estimated testing to take approximately 20 weeks per chemistry and stated it could take up to 2+ years for individual vendors to have required documentation. The commenter also expressed concern that the proposed requirements could have cascading impacts to facility manufacturing and operating permits based on state implementation of the Tailoring Rule, which typically rely on GHGRP protocols. Commenters supported aligning the emission control device operational requirements for default POU DREs with the following 2019 Refinement language: ''. . . obtain a certification by the emissions control system manufacturers that their emissions control systems are capable of removing a particular gas to at least the default DRE in the worst-case flow conditions, as defined by each reporting site.''

The commenter also requested the EPA include language supporting full uptime for emission control devices interlocked with manufacturing tools or with abatement redundancy. The commenter supported 2019 Refinement language that: ''Inventory compilers should also note that UT [uptime] may be set to one (1) if suitable backup emissions control equipment or interlocking with the process tool is implemented for each emissions control system. Thus, using interlocked process tools or backup emissions control systems reduces uncertainty by eliminating the need to estimate UT for the reporting facility.'' The commenter contended that such language will drive further use of manufacturing tool interlocks or emission control system redundancy while having the added benefit of simplifying uptime tracking of individual POU.

Response: The EPA is clarifying in this response that reporters are not required to maintain documentation of the DRE on abatement units for which a DRE is not being claimed. However, no regulatory changes are needed to reflect this clarification. For abatement units for which a DRE is being claimed, reporters are still required to provide certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG or N_2O abatement, as applicable, and support the certification by providing abatement system supplier documentation stating that the system was designed for fluorinated GHG or N_2O abatement. The facility must certify that the DRE provided by the abatement system manufacturer is greater than or equal to the DRE claimed (either the default, if the certified DRE is greater than or equal to the default, or the manufacturer-verified DRE itself, if the certified DRE is lower than the default DRE). To use the default or lower manufacturer-verified destruction or removal efficiency values, operation of the abatement system must be within the manufacturer's specifications. It was not the EPA's intent to require that certified abatement systems that operate within the manufacturer's specifications must meet all the operational parameters listed, and we are revising the final rule at 40 CFR 98.96(q)(2) to add ''which may include, for example,'' to clarify that, in order to use the default or lower manufacturer-verified destruction or removal efficiency values, operation of the abatement system must be within those manufacturer's specifications that apply for the certification.

In the final rule, the EPA is maintaining the current certification and documentation requirements for older POU abatement devices, although the certification must contain a manufacturer-verified DRE value that is equal to or higher than the default in order to claim the default DRE; facilities are allowed to claim a lower manufacturer-verified value if the provided certified DRE is lower than the default. The EPA concurs that some older POU abatement systems may not have full documentation from the manufacturer of the test methods used and whether testing was conducted under worst-case flow conditions; however, we believe this documentation should be available for most newer abatement systems. As a result, reporters with the older POU abatement devices will not have any additional documentation requirements beyond those currently in place, except to provide the certified DRE. Following a review of annual reports submitted under subpart I, we determined that facilities have historically provided manufacturer-verified DRE values for all abatement systems for which emission reductions have been claimed. Therefore, we have determined that these final requirements are reasonable. The EPA is finalizing the new documentation requirements for POU abatement devices purchased on or after January 1, 2025 under 40 CFR 98.94(f)(3)(i) and (ii), these additional requirements include that the manufacturer-verified DREs reflect that the abatement system has been tested by the manufacturer using a scientifically sound, industry-accepted measurement methodology that accounts for dilution through the abatement system, such as the EPA DRE Protocol (EPA 430–R–10–003), and verified to meet (or exceed) the default destruction or removal efficiency for the fluorinated GHG or N_2O under worst-case flow conditions. Since manufacturers routinely conduct DRE testing and are familiar with the protocols of EPA 430–R–10–003, this information would be readily available for abatement systems purchased in calendar year 2025 or later. Further, these final rule requirements will be implemented for reports prepared for RY2025 and submitted March 31, 2026, providing adequate time for reporters to acquire documentation.

The EPA agrees with the recommendation to align the rule with the 2019 Refinement with respect to the uptime factor for interlocked tools and abatement systems and is making this change in the final rule. The use of interlocked tools is already accounted for in the current rule in the definition of terms ''UT_{ijp}'' and ''UT_{pf}'' in equations I–15 and I–23 (the total time in minutes per year in which the abatement system has at least one associated tool in operation), which state that ''[i]f you have tools that are idle with no gas flow through the tool for part of the year, you may calculate total tool time using the actual time that gas is flowing through the tool.'' However, to clarify and simplify the calculation of uptime where interlocked tools are used, the EPA is revising the definition of the term ''UT_{ij}'' in equation I–15 to say that if all the abatement systems for the relevant input gas and process type are interlocked with all the tools feeding them, the uptime may be set to one (1). The revised text specifies that ''all'' tools and abatement systems for the relevant input gas and process sub-type or type are interlocked because the numerator and denominator of the uptime calculation in equations I–15 and I–23 are separately summed across abatement systems for input gas ''i'' and process sub-type or type ''j.'' Similar changes are made for the same reasons in the definition of ''UT_f'' in equation I–23. With the use of an interlock between the process tool and abatement device, the process tool should never be operating when the abatement device is not operating.

The current rule also accounts for the use of redundant abatement systems. Section 98.94(f)(4)(vi) currently states, ''If your fab uses redundant abatement systems, you may account for the total abatement system uptime (that is, the time that at least one abatement system is in operational mode) calculated for a specific exhaust stream during the reporting year.'' This provision achieves nearly the same objective as suggested by the commenters. To clarify this point, the EPA is revising the definition of the terms ''Td_{ijp}'' in equation I–15 and ''Td_{pf}'' in equation I–23 to reference the provision in 40 CFR 98.94(f)(4)(vi) when accounting for uptime when redundant abatement systems are used.

Comment: Commenters objected to the EPA's proposed requirements to include a calculation methodology to estimate emissions of CF_4 produced in hydrocarbon-fuel based combustion emissions control systems (HC fuel CECS) that are not certified not to generate CF_4. The commenters claimed that the CF_4 byproduct emissions from HC fuel CEC abatement of F_2 gas (from etch or remote plasma chamber cleaning processes) are based on limited and unverified data. Specifically, the commenters expressed concern that the values documented within the 2019 Refinement and referenced within the proposal are based on a single, confidential data set from one abatement supplier. One commenter stated that developing regulatory language around this single, unverified data set does not accurately represent the CF_4 byproduct emissions from the uses or generation of F_2 and may deliver an advantage to the single emissions control system supplier that provided the data.

The commenters also listed the following concerns with the information provided within the 2019 Refinement and the proposed rule supporting documentation upon which the CF_4 byproduct ($AB_{CF4,F2}$ and $B_{F2,NF3}$) is based:

- The F_2 emission values presented in ''Influence of CH_4-F_2 mixing on CF_4 byproduct formation in the combustive abatement of F_2'' by Gray & Banu (2018) are based on testing conducted in a lab under conditions that are not found in actual semiconductor abatement installations. Test methods do not appear to adhere to those specified in industry standard test methods or the EPA DRE Protocol. F_2 results are measured from a device, the MST Satellite XT, designed to provide ''nominal'' F_2 concentrations meant for health and safety risk management and not for environmental emissions measurement.
- ''FTIR spectrometers measure scrubber abatement efficiencies'' by Li, et al. (2002) and ''Thermochemical and Chemical Kinetic Data for Fluorinated Hydrocarbons'' by Burgess, et al. (1996) provide anecdotal and hypothetical emission pathways for the combustion of fluorinated gases, but do not confirm

reliable and peer reviewed CF_4 emission results from current semiconductor manufacturing use or generation of F_2.

- EPA references a single, confidential data set from Edwards, Ltd. (2018) upon which numerical $AB_{CF4,F2}$ and $B_{F2,NF3}$ values are based. This single data set of 15 measurements refers to an RPC NF_3 to F_2 emission value based on mass balance. The commenter opposed using the data provided by Edwards confidentially without the ability to review the underlying data and experimental procedure of the 15 measurements upon which the RPC NF_3 to F_2 emission factor was based. Mass balance has shown to be a highly conservative method in estimating emission factors and this confidential data set lacks visibility into repeatability, experimental design, and semiconductor process applicability.

The commenters further contended that the requirement to calculate CF_4 emissions from HC fuel CECS abatement of F_2, based on equation I–9 if the HC fuel CECS is not certified to not convert F_2 at less than 0.1%, adds complexity to apportioning RPC NF_3 and F_2 to both <0.1% certified and uncertified HC fuel CECS and will require time and cost investments which are not justified by data. One commenter added that this could disincentivize the use of low emission NF_3 cleans or potentially slow implementation of F_2 processes with zero-GWP potential due to the requirement to report CF_4 BEF generation with tools with POU abatement. Another commenter added that this requirement appears to apply to all relevant HC fuel CECS regardless of whether a default or measured DRE is claimed for the abatement device. The commenter stated that if HC fuel CECS abatement suppliers and device manufacturers are not able to provide the required certification to exempt systems from this added emission, for every kilogram of RPC NF_3 used, CO_2e emissions out of the HC fuel CECS will increase more than 600% for 200 mm and more than 400% for 300 mm processes. Commenters added that this jump in CF_4 emissions will result in a time series inconsistency for semiconductor industry greenhouse gas reporting.

One commenter also stated that, if EPA maintains this requirement, it is unclear if equation I–9 applies in addition to or in place of existing CF_4 byproduct emission factors. The commenter requested that CF_4 emissions from the HC fuel CECS abatement of F_2, as calculated by equation I–9, are applied instead of, not in addition to, default CF_4 BEFs for RPC NF_3. Commenters requested the removal of equation I–9 and associated $AB_{CF4,F2}$ and $B_{F2,NF3}$ data elements; one commenter added that an alternative would be to make changes to HC fuel CECS requirements to remove confusion and double counting of emissions.

Response: The EPA disagrees with the commenter after a thorough review of the issue, as documented in detail in a memorandum in the docket for the final rulemaking.[14] The analysis conducted for the EPA demonstrated that: (1) the formation of CF_4 by reaction of CH_4 and F_2 in POU combustion systems is thermodynamically favored and that there is no question that CF_4 emissions can be observed if mixing of CH_4 and F_2 is allowed to occur; (2) that a revised $B_{F2,NF3}$ default emission factor of 0.5 is well supported by scientific peer-reviewed evidence to describe the formation of F_2 from NF_3-based RPC processes; (3) that the proposed default value for $AB_{CF4,F2}$ of 0.116, describing the rate of formation of CF_4 from F_2, is well supported by experimental evidence under conditions that are representative of the designs and use of commercially available POU emissions control systems in production conditions; (4) that there is strong *prima facie* evidence of the formation of CF_4 from within POU emissions control systems during the production of semiconductor devices; and (5) that not reporting such CF_4 emissions could lead to a significant underestimation of GHG emissions from semiconductor manufacturing facilities.

Based on the evidence documented in the memorandum, the EPA is finalizing as proposed the requirement that the electronic manufacturers estimate and report CF_4 byproduct emissions from hydrocarbon-fuel-based POU emissions control systems that abate F_2 processes or NF_3-based RPC processes.

The EPA is also requiring that reporters estimate CF_4 emissions from all POU abatement devices that are not certified not to produce CF_4, even if they are not claiming a DRE from those devices, because the CF_4 emissions from HC fuel combustion in the abatement of F_2 or F–GHG is a separate issue from whether or not a DRE is claimed for the same devices. The EPA disagrees that the rule is adding unnecessary complexity to apportion RPC NF_3 and F_2 between POU abatement systems that are certified not to convert F_2 to CF_4 and those that are not certified. Reporters will use tool counts in this case rather than the usual gas apportioning model. This should be straightforward because it requires the reporters to: (1) count the total number of tools running the process type of interest (either RPC NF_3 or F_2 in any process type); (2) count the number of tools running that process type that are equipped with HC fuel CECs that are not certified not to form CF_4; and (3) divide (2) by (1).

The EPA is revising the final rule to require that reporters must only provide estimates of CF_4 emissions from HC fuel CECS purchased and installed on or after January 1, 2025. We recognize that applying the testing, certification, and emissions estimation requirements to older equipment would have expanded the set of equipment for which testing would need to be performed and/or emissions would need to be estimated, which may have posed logistical challenges, particularly for older equipment that may no longer be manufactured. Making the requirements applicable only to HC fuel CECs purchased and installed on or after January 1, 2025 ensures that abatement system manufacturers and/or electronics manufacturers can test the equipment and measure its CF_4 generation rate from F_2 by March 31, 2026, by which time facilities must either certify that the HC fuel CECS do not generate CF_4 or quantify CF_4 emissions from the HC fuel CECS.

The EPA recognizes that the new requirement to report CF_4 emissions from HC fuel CECS could lead to a time series inconsistency in reported emissions. However, such an inconsistency is not in conflict with the overall purpose of the GHGRP to accurately estimate GHG emissions. Nor would it be unique to the electronics industry, because other GHGRP subparts have been revised in ways that altered the time series of the emissions as new source types were added or more accurate methods were adopted. For example, in 2015, subpart W was updated to include a new source, completions and workovers of oil wells with hydraulic fracturing, in the existing Onshore Petroleum and Natural Gas Production segment and also added two entirely new segments, the Onshore Petroleum and Natural Gas Gathering and Boosting and Onshore Natural Gas Transmission Pipelines segments. Such changes in reported emissions are often documented in the public data, including in the EPA's sector profiles.

The EPA is clarifying in this response to comment that equation I–9 is in addition to, rather than in place of, CF_4 byproduct factors for RPC NF_3, because the CF_4 byproduct factors for RPC NF_3

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[14] Memorandum from Sebastien Raoux to U.S. EPA. ''CF_4 byproduct formation from the combustion of CH_4 and F_2 in Point of Use emissions control systems in the electronics industry.'' Prepared for the U.S. EPA. May 2023, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

represent emissions from the process before abatement, and these emissions were measured without abatement equipment running.

Comment: One commenter supported using the term ''hydrocarbon-fuel-based combustion emissions control systems'' (HC fuel CECS) because it aligns with the nomenclature within 2019 Refinement rather than the less used ''hydrocarbon-fueled abatement systems'' or other terms. The commenter explained that semiconductor facilities widely implement large, facility-level volatile organic compound abatement devices to eliminate and control criteria volatile and non-volatile organic compounds, with no expectation of fluorinated greenhouse gas emissions. The commenter expressed concern that the broad definition of HC fuel CECS may be interpreted to include all hydrocarbon-based fuel control systems, not just tool-level POU abatement. The commenter added that, although not currently implemented, future facility-level F–GHG abatement systems could be incorrectly included in the scope of equation I–9 as it is written. The commenter requested that all emissions control systems language is updated to be consistent. The commenter also specifically requested the definition of ''hydrocarbon-fuel-based combustion emission control systems'' be tailored to specify HC fuel CECS connected to manufacturing tools, and include the following language: ''and have the potential to emit fluorinated greenhouse gases.''

Response: The EPA agrees with the commenter and has revised the proposed language to include the term, ''hydrocarbon-fuel-based combustion emissions control systems'' (HC fuel CECS) to align with the nomenclature within 2019 Refinement. The EPA is also clarifying in the final rule that these requirements apply only to equipment that is connected to manufacturing tools that have the potential to emit F_2 or F–GHGs. It is important to include emissions of F_2 as well as F–GHGs since it is F_2 that may combine with hydrocarbon fuels to generate CF_4 emissions. These changes include revising ''hydrocarbon fuel-based emissions control systems'' to ''HC fuel CECS'' in the terms ''EAB_{CF4},'' $a_{F2,j}$,'' ''$UT_{F2,j}$,'' ''$AB_{CF4,F2}$,'' ''$a_{NF3,RPC}$,'' ''and ''$UT_{NF3,RPC,F2}$'' defined in equation I–9.

Comment: One commenter requested the EPA specify that HC fuel CECS uptime during stack testing is ''representative of the emissions stream'' and the EPA specify that HC fuel CECS uptime during stack testing applies to RPC NF_3 or input F_2 processes only. The commenter questioned the EPA's proposed requirement that the uptime during the stack testing period must average at least 90 percent for uncertified hydrocarbon-fueled emissions control systems. The commenters asserted that uptime tracking for uncertified abatement devices is excessive, goes beyond the 2019 Refinement requirements, and does not improve the accuracy of emissions estimates. The commenter requested language to limit this requirement to ''at least 90% uptime of NF_3 remote plasma clean HC fuel CECS devices that are not certified to not form CF_4 during the test.'' The commenter also requested EPA clarify that equation I–9 does not apply in addition to stack testing requirements. The commenter requested that CF_4 emissions from the HC fuel CECS abatement of F_2, as calculated by equation I–9, be specifically exempted from the stack testing method as it would double count CF_4 emissions.

Response: The EPA agrees with the commenter that it would be helpful to clarify of the applicability of the 90-percent uptime requirement for HC fuel CECS. The EPA is revising the rule language at 40 CFR 98.94(j)(1) to further limit the HC fuel CECS 90-percent uptime requirement to systems that were purchased and installed on or after January 1, 2025 and that are used to control emissions from tools that use either NF_3 in remote plasma cleaning processes or F_2 as an input gas in any process type or sub-type. Either of these input gas-process type combinations may exhaust F_2 into HC fuel CECS, potentially leading to the formation of CF_4. The qualification ''that are not certified not to form CF_4'' is being finalized as proposed.

Regarding the commenters' concerns related to the uptime tracking requirements for uncertified abatement devices during stack testing, we reiterate that the uptime tracking requirement during stack testing is for hydrocarbon-fueled abatement devices that are not certified to not form CF_4, because these reporters still need to account for CF_4 emissions even if not accounting the abatement device's F–GHG DRE.

The EPA is also clarifying in this response that equation I–9 is *not* in addition to stack test calculations. The emissions from HC fuel CECS, should they occur, will be captured by the stack testing measurements. Because equation I–9 is not included in or referenced by the stack testing section, the regulatory text in 40 CFR 98.93(i) as currently drafted does not need any additional revision. However, the header paragraph 40 CFR 98.93(a) has been revised to clarify that paragraph (a)(7), which includes equation I–9, is one of the paragraphs used to calculate emissions based on default gas utilization rates and byproduct formations rates.

Comment: One commenter objected to the EPA's proposed calibration requirements for abatement systems, specifically for vacuum pump purge systems. The commenter urged that this would have significant impacts on the semiconductor industry and would drive a major increase in pump replacement and tool downtime. The commenter explained that POU abatement devices and their connected vacuum pumps are separate systems, and while physically connected, POU maintenance and pump replacement schedules are independent of one another. Further, the commenter asserted that pump purge flow calibration is technically and operationally infeasible for device manufacturers to perform. The commenter explained that purge flow indicators are factory calibrated and are part of the pump installation and commissioning; if there is a flow indicator failure, the vacuum pump is replaced with a factory-calibrated pump. The commenter stated that pump maintenance and repair is not typically performed at the manufacturing tool and requires pump disconnection and physical removal, and thus pumps are often repaired off-site. The commenter stressed that pump manufacturers do not provide recommendations or specifications for re-calibration of these pumps. The commenter added that there is no pump redundancy installed on a tool, and to check the calibration and potentially replace the flow transducer, the vacuum pump must be shutdown to safely work on it. The commenter noted that any replacement of the pump would require a tool shutdown and therefore 12 to 48 hours of downtime for manufacturing requalification.

The commenter stated that pumps remain continually in service on the order of years and asserted that pump vendors indicate that pumps can remain in service for many years without requiring calibration of the pump purge. The commenter provided that pump changes and refurbishment costs can be over $5,000 per occurrence and noted that pump repair or calibration activities can require significant coordination with factory and site operations due to the highly specialized equipment and resources needed. The commenter estimated that semiconductor manufacturing sites can have 2,000+ POU abatement devices as well as 4,000+ vacuum pumps in a high-volume-manufacturing site. The commenter subsequently estimated that the EPA's proposed revisions could result in pump downtime, process equipment tool downtime, and maintenance costs to the U.S. semiconductor industry of about $40 million annually.

The commenter also stated that they believe the existing performance certification of POU emissions control devices based on high flow conditions are highly protective of POU system reliability. The commenter reiterated that high flow POU certification is based on maximum device flows, which, for multi-chamber tools, includes all chambers running at once. The commenter urged that significant variations in pump purge flows are unlikely and the magnitude of these variations would be a small component of overall POU flow volumes. As such, the commenter urged that pump purge flows are not necessary to calibrate after initial pump commissioning.

Response: The EPA agrees with the commenter that calibration of N_2 purge flows is normally done during pump service or maintenance, when the pumps are typically: (1) disconnected from the process tool; (2) replaced by a new or refurbished pump; and (3) brought to a ''service center'' for refurbishment (sometimes on-site, sometimes off-site). The EPA also concurs with commenters that requiring N_2 pump purge calibration could be disruptive if done outside of ''normal'' service periods. Consequently, the EPA proposed to require that pump purge flow indicators be calibrated ''each time a vacuum pump is serviced or exchanged'' rather than more frequently. The anticipated frequency of calibration mentioned in the preamble, every six months, was intended to be descriptive rather than prescriptive. Thus, the EPA does not believe that the proposed requirement would have the large economic impacts cited by the commenter. Nevertheless, because it appears that pumps are typically factory calibrated when commissioned and are replaced with factory-calibrated pumps when the flow indicator fails, a calibration requirement is not required. Therefore, the EPA is not taking final action on the proposed calibration requirement.

b. Comments on Revisions To Streamline and Improve Implementation for Subpart I

Comment: One commenter supported finalizing the amendment to 40 CFR 98.96(y) decreasing the frequency of submission of technology assessment reports, before the due date for the next technology assessment report.

Response: The EPA acknowledges the commenter's support and is finalizing revisions to 40 CFR 98.96(y) to decrease the frequency of submission of technology assessment reporters to every 5 years, as proposed. However, because the EPA is not implementing the final revisions until January 1, 2025 (see section V. of this preamble), we have revised the provision to clarify that the first technology assessment report due after January 1, 2025 is due on March 31, 2028. Subsequent reports must be submitted every 5 years no later than March 31 of the year in which it is due.

H. Subpart N—Glass Production

We are finalizing several amendments to subpart N of part 98 (Glass Production) as proposed. The EPA received only supportive comments for the proposed revisions to subpart N. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart N. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the revisions to subpart N, as described in section VI. of this preamble.

The EPA is finalizing two revisions to the recordkeeping and reporting requirements of subpart N of part 98 (Glass Production) as proposed in the 2022 Data Quality Improvement Proposal. The revisions apply to both CEMS and non-CEMS reporters and require that facilities report and maintain records of annual glass production by glass type (*e.g.,* container, flat glass, fiber glass, specialty glass). Specifically, the final amendments revise (1) 40 CFR 98.146(a)(2) and (b)(3) to require the annual quantity of glass produced in tons, by glass type, from each continuous glass melting furnace and from all furnaces combined; and (2) 40 CFR 98.147(a)(1) and (b)(1), to add that records must also be kept on the basis of glass type. Differences in the composition profile of raw materials, use of recycled material, and other factors lead to differences in emissions from the production of different glass types. Collecting data on the annual quantities of glass produced by type will improve the EPA's understanding of emissions variations and industry trends, and improve verification for the GHGRP, as well as provide useful information to improve analysis of this sector in the Inventory. The EPA is also finalizing revisions to the recordkeeping and reporting requirements of subpart N as proposed in the 2023 Supplemental Proposal. The final revisions add reporting provisions at 40 CFR 98.146(a)(3) and (b)(4) to require the annual quantity (in tons), by glass type (*e.g.,* container, flat glass, fiber glass, or specialty glass), of cullet charged to each continuous glass melting furnace and in all furnaces combined, and revises 40 CFR 98.146(b)(9) to require the number of times in the reporting year that missing data procedures were used to measure monthly quantities of cullet used. The final revisions also add recordkeeping provisions to 40 CFR 98.147(a)(3) and (b)(3) to require the monthly quantity of cullet (in tons) charged to each continuous glass melting furnace by product type (*e.g.,* container, flat glass, fiber glass, or specialty glass). Differences in the quantities of cullet used in the production of different glass types can lead to variations in emissions, and, due to lower melting temperatures, can reduce the amount of energy and combustion required to produce glass. As such, the annual quantities of cullet used will further improve the EPA's understanding of variations and differences in emissions estimates, industry trends, and verification, as well as improve analysis for the Inventory. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

I. Subpart P—Hydrogen Production

We are finalizing several amendments to subpart P of part 98 (Hydrogen Production) as proposed. In some cases, we are finalizing the proposed amendments with revisions. In other cases, we are not taking final action on the proposed amendments. Section III.I.1. of this preamble discusses the final revisions to subpart P. The EPA received several comments on the proposed subpart P revisions which are discussed in section III.I.2. of this preamble. We are also finalizing related confidentiality determinations for data elements resulting from the revisions to subpart P, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart P

This section summarizes the final amendments to subpart P. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other final revisions to 40 CFR part 98, subpart P can be found in this section and section III.I.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Revisions To Improve the Quality of Data Collected for Subpart P

In the 2023 Supplemental Proposal, the EPA proposed several amendments to subpart P of part 98 to expand and clarify the source category definition. First, to increase the GHGRP's coverage of facilities in the hydrogen production sector, we are amending, as proposed, the source category definition in 40 CFR 98.160 to include all facilities that produce hydrogen gas regardless of whether the hydrogen gas is sold. The final revisions will address potential gaps in applicability and reporting, allowing the EPA to better understand and track emissions from facilities that do not sell hydrogen gas to other entities. As proposed, these amendments categorically exempt any process unit for which emissions are currently reported under another subpart of part 98, including, but not necessarily limited to, ammonia production units that report emissions under subpart G of part 98 (Ammonia Manufacturing), catalytic reforming units located at petroleum refineries that produce hydrogen as a byproduct for which emissions are reported under subpart Y of part 98 (Petroleum Refineries), and petrochemical production units that report emissions under subpart X of part 98 (Petrochemical Production). As proposed, we are also exempting process units that only separate out diatomic hydrogen from a gaseous mixture and are not associated with a unit that produces diatomic hydrogen created by transformation of feedstocks.

The EPA is also amending the source category definition at 40 CFR 98.160 as proposed to clarify that stationary combustion sources that are part of the hydrogen production unit (*e.g.,* reforming furnaces and hydrogen production process unit heaters) are part of the hydrogen production source category and that their emissions are to be reported under subpart P. These amendments, which include a harmonizing change at 40 CFR 98.162(a), clarify that these furnaces or process heaters are part of the hydrogen production process unit regardless of where the emissions are exhausted (through the same stack or through separate stacks). Similarly, we are finalizing a clarification for hydrogen production units with separate stacks for ''process'' emissions and ''combustion'' emission that use a CEMS to quantify emissions from the process emissions stack. The final amendments at 40 CFR 98.163(c) require reporters to calculate and report the CO_2 emissions from the hydrogen production unit's fuel combustion using the mass balance equations (equations P–1 through P–3) in addition to calculating and reporting the process CO_2 emissions measured by the CEMS. Additional information on these revisions and their supporting basis may be found in section III.G. of the preamble to the 2023 Supplemental Proposal. We are adding one additional revision to address the monitoring of stationary combustion units directly associated with hydrogen production (*e.g.,* reforming furnaces and hydrogen production process unit heaters), following a review of comments received. Based on the EPA's analysis of reported data, there may be a small number of reporters that may not currently measure the fuel use to these combustion units separately. We have decided to add new § 98.164(c) to provide the use of best available monitoring methods (BAMM) for those facilities that may still need to install monitoring equipment to measure the fuel used by each stationary combustion unit directly associated with the hydrogen production process unit. To be eligible to use BAMM, the stationary combustion unit must be directly associated with hydrogen production; the unit must not have a measurement device installed as of January 1, 2025; the hydrogen production unit and the stationary combustion unit are operated continuously; and the installation of a measurement device must require a planned process equipment or unit shutdown or only be able to be done through a hot tap. BAMM can be the use of supplier data, engineering calculation methods, or other company records. We are not requiring facilities to provide an application to use BAMM that would require EPA review and approval to measure the fuel used in the hydrogen production process combustion unit. However, we are adding a new requirement at 40 CFR 98.166(d)(10) to require each facility to indicate in their annual report, for each stationary combustion unit directly associated with hydrogen production, whether they are using BAMM, the date they began using BAMM, and the anticipated or actual end date of BAMM use. Providing the use of BAMM is intended to reduce the burden associated with installation of new equipment, and we do not anticipate that the requirement to report the required indicators of BAMM will add significant burden. See section III.I.2. of this preamble for additional information on related comments and the EPA's response.

In the 2022 Data Quality Improvements Proposal, the EPA proposed several amendments to subpart P to allow the subtraction of the mass of carbon contained in products (other than CO_2 or methanol) and the carbon contained in intentionally produced methanol from the carbon mass balance used to estimate CO_2 emissions. The proposed revisions included new equation P–4 to allow facilities to adjust the calculated emissions from fuel and feedstock consumption in order to calculate net CO_2 process emissions, as well as harmonizing revisions to the introductory paragraph of 40 CFR 98.163 and 98.163(b) and the reporting requirements at 40 CFR 98.167(b)(7). Following review of comments received on similar changes proposed for subpart S (Lime Manufacturing), the EPA is not taking final action at this time on the proposed revisions to allow facilities to subtract out carbon contained in products other than CO_2 or methanol and the carbon contained in methanol. See sections III.E., III.I.2., and III.K.2. of this preamble for additional information on the comments related to subparts G, P and S and the EPA's response. However, the EPA is finalizing the proposed reporting requirement at 40 CFR 98.166(b)(7) (now 40 CFR 98.166(d)(7)), with minor revisions as a result of comments received. See the discussion in this section regarding subpart P reporting requirements for additional information as to why EPA is making revisions as a result of comments received.

The EPA is finalizing several additional revisions to the subpart P reporting requirements to improve the quality of the data collected based on the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal. The final reporting requirements are reorganized to accommodate the final amendments at 40 CFR 98.163(c), which require reporters using CEMS that do not include combustion emissions from the hydrogen production unit to calculate and report the CO_2 emissions from fuel combustion using the material balance equations (equations P–1 through P–3) in addition to the process CO_2 emissions measured by the CEMS. The revisions to 40 CFR 98.166 clarify the reporting elements that must be provided for each hydrogen production process unit based on the calculation methodologies used. Reporters using CEMS to measure combined CO_2 process and fuel combustion emissions will be required to meet the requirements at 40 CFR 98.166(b); reporters using only the material balance method will be required to meet the requirements at 40 CFR 98.166(c); and reporters using CEMS to measure CO_2 process emissions and the material balance method to calculate emissions from fuel combustion emissions using equations P–1 through P–3 will be required to meet the requirements of 40 CFR 98.166(b) and (c). If a common stack CEMS is used to measure emissions from either a common stack for multiple hydrogen production units or a common stack for hydrogen production unit(s) and other source(s), reporters must also report the estimated fraction of CO_2 emissions attributable to each hydrogen production process unit. All other reporting requirements for each hydrogen production process unit (regardless of the calculation method) are consolidated under 40 CFR 98.166(d).

As proposed, we are finalizing the addition of requirements for facilities to report the process type for each hydrogen production unit (*i.e.,* steam methane reforming (SMR), SMR followed by water gas shift reaction (SMR–WGS), partial oxidation (POX), partial oxidation followed by WGS (POX–WGS), Water Electrolysis, Brine Electrolysis, or Other (specify)), and the purification type for each hydrogen production unit (*i.e.,* pressure swing adsorption (PSA), Amine Adsorption, Membrane Separation, Other (specify), or none); the final requirements have been moved to 40 CFR 98.166(d)(1) and (2) and paragraph (d)(1) has been revised to include ''autothermal reforming only'' and ''autothermal reforming followed by WGS'' as additional unit types.

We are amending, as proposed, requirements to clarify that the annual quantity of hydrogen produced is the quantity of hydrogen that is produced ''. . . by reforming, gasification, oxidation, reaction, or other transformations of feedstocks,'' and to add reporting for the annual quantity of hydrogen that is only purified by each hydrogen production unit; the final requirements have been moved to 40 CFR 98.166(d)(3) and (4).

We are finalizing a requirement at 40 CFR 98.166(c) (proposed 40 CFR 98.166(b)(5)), to report the name and annual quantity (metric tons (mt)) of each carbon-containing fuel and feedstock (formerly 40 CFR 98.166(b)(7)). For clarity, we have revised the text of the requirement at 40 CFR 98.166(c) from proposal to specify that the information is required whenever equations P–1 through P–3 are used to calculate CO_2 emissions. We are finalizing revisions that renumber 40 CFR 98.166(c) and (d) (now 40 CFR 98.166(d)(6) and (7)), and are finalizing paragraph (d)(7) with revisions from those proposed to require reporting, on a unit-level: (1) the quantity of CO_2 that is collected and transferred off-site; and (2) the quantity of carbon other than CO_2 or methanol collected and transferred off-site, or transferred to a separate process unit within the facility for which GHG emissions associated with the carbon is being reported under other provisions of part 98. The final rule also requires at 40 CFR 98.166(d)(9) the reporting of the annual net quantity of steam consumed by the unit (proposed as 40 CFR 98.166(c)(9)). This value will be a positive quantity if the hydrogen production unit is a net steam user (*i.e.,* uses more steam than it produces) and a negative quantity if the hydrogen production unit is a net steam producer (*i.e.,* produces more steam than it uses).

Finally, for consistency with the final revisions to the reporting requirements for facilities subject to revised 40 CFR 98.163(c), we are making a harmonizing change to the recordkeeping requirements at 40 CFR 98.167(a) to specify that, if the facility CEMS measures emissions from a common stack for multiple hydrogen production units or emissions from a common stack for hydrogen production unit(s) and other source(s), reporters must maintain records used to estimate the decimal fraction of the total annual CO_2 emissions from the CEMS monitoring location attributable to each hydrogen production unit. We are also finalizing as proposed clarifying edits in 40 CFR 98.167(e) that retention of the file required under that provision satisfies the recordkeeping requirements for each hydrogen production unit. See section III.G.1. of the preamble to the 2022 Data Quality Improvements Proposal and section III.G. of the preamble to the 2023 Supplemental Proposal for additional information on these revisions and their supporting basis.

In the 2023 Supplemental Proposal, the EPA also requested comment on, but did not propose, other potential revisions to subpart P, including revisions that would remove the 25,000 $mtCO_2e$ threshold under 40 CFR 98.2(a)(2), which would result in a requirement that any facility meeting the definition of the hydrogen production category in 40 CFR 98.160 report annual emissions to the GHGRP. The EPA considered these changes in order to collect information on facilities that use electrolysis or other production methods that may have small direct emissions, but that may use relatively large amounts of off-site energy to power the process (*i.e.,* the emissions occurring on-site at these hydrogen production facilities may fall below the existing applicability threshold, while the combined direct emissions (*i.e.,* ''scope 1'' emissions) and emissions attributable to energy consumption (*i.e.,* ''scope 2'' emissions) could be relatively large), as collecting information from these kinds of facilities as well is especially important in understanding hydrogen as a fuel source. To reduce the burden on small producers, the EPA requested comment on applying a minimum annual production quantity within the source category definition to limit the applicability of the source category to larger hydrogen production facilities, such as defining the source category to only include those hydrogen production processes that exceed a 2,500 metric ton (mt) hydrogen production threshold. The EPA also requested comment on potential options to require continued reporting from hydrogen production facilities that use electrolysis or other production methods that may have small direct emissions (*i.e.,* scope 1 emissions) that would likely qualify to cease reporting after three to five years under the part 98 ''off-ramp'' provisions of 40 CFR 98.2(i) (*i.e.,* facilities may stop reporting after three years if their emissions are under 15,000 $mtCO_2e$ or after five years if their emissions are between 15,000 and 25,000 $mtCO_2e$), to enable collection of a more comprehensive data set over time. Following consideration of comments received, the EPA is not taking final action on these potential revisions in this rule. See section III.I.2. of this preamble for additional information on related comments and the EPA's responses. The EPA also considered, but did not propose, further expanding the reporting requirements to include the quantity of hydrogen provided to each end-user (including both on-site use and delivered hydrogen) and, if the end-user reports to GHGRP, the e-GGRT identifier for that customer. The EPA requested comment on the approach to collecting this sales information and the burden such a requirement may impose in the 2023 Supplemental Proposal. Following review of comments received, the EPA is not taking final action on these potential revisions in this rule.

b. Revisions To Streamline and Improve Implementation for Subpart P

The EPA is finalizing several revisions to subpart P to streamline the requirements of this subpart and improve flexibility for reporters. To address the recent use of low carbon content feedstocks, the EPA is finalizing, with revisions from those proposed, revisions to 40 CFR 98.164(b)(2) and (3) to allow the use of product specification information annually as specified in the final provisions for (1) gaseous fuels and feedstocks that have carbon content less than or equal to 20 parts per million by weight (*i.e.,* 0.00002 kg carbon per kg of gaseous fuel or feedstock) (rather than at least weekly sampling and analysis), and (2) for liquid fuels and feedstocks that have a carbon content of less than or equal to 0.00006 kg carbon per gallon of liquid fuel or feedstock (rather than monthly sampling and analysis). As explained in the 2022 Data Quality Improvements Proposal, the fuels and feedstocks below these concentrations have very limited GHG emission potential and are currently an insignificant contribution to the GHG emissions from hydrogen production. The revisions from those proposed were included to remove the term ''non-hydrocarbon'' because it is not necessary since the maximum hydrocarbon concentrations that qualify for the revised monitoring requirements are included in 40 CFR 98.164(b)(2) and (3).

The EPA is finalizing, with revisions from those proposed, the addition of new 40 CFR 98.164(b)(5)(xix) to allow the use of modifications of the methods listed in 40 CFR 98.164(b)(5)(i) through (xviii) or use of other methods that are applicable to the fuel or feedstock if the methods currently in 40 CFR 98.164(b)(5) are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe. The revisions from those proposed were harmonizing changes to remove the term ''non-hydrocarbon'' and tie the proposed revisions back more clearly to the specifications in paragraphs (b)(2) and (3).

The final rule also finalizes as proposed, revisions to § 98.164(b)(2) through (4) to specifically state that the carbon content must be determined ''. . . using the applicable methods in paragraph (b)(5) of this section'' to clarify the linkage between the requirements in § 98.164(b)(2) through (4) and § 98.164(b)(5).

Finally, the EPA is finalizing revisions to the recordkeeping requirements at 40 CFR 98.167(b) to refer to paragraph (b) of 40 CFR 98.166. For facilities using the alternatives at 40 CFR 98.164(b)(2), (3) or (5)(xix), these requirements include retention of product specification sheets, records of modifications to the methods listed in 40 CFR 98.164(b)(5)(i) through (xviii) that are used, and records of the alternative methods used, as applicable. We are also finalizing a revision to remove and reserve redundant recordkeeping requirements in 40 CFR 98.167(c). See section III.G.2. of the preamble to the 2022 Data Quality Improvements Proposal and section III.G. of the preamble to the 2023 Supplemental Proposal for additional information on these revisions and their supporting basis.

2. Summary of Comments and Responses on Subpart P

This section summarizes the major comments and responses related to the proposed amendments to subpart P. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart P.

Comment: Two commenters recommended expanding the source category to include all hydrogen production facilities; this would include non-merchant producers, facilities that use electrolysis or renewable energy, and include process units that do not report to other subparts. Other commenters did not oppose expanding the source category to non-merchant facilities. One commenter on the 2022 Data Quality Improvements Proposal stated that the existing definition may cause confusion in situations where the hydrogen produced is used on-site or otherwise not ''sold as a product to other entities'' and suggested specific revisions to expand the source category to include other types of hydrogen production plants, including those using electrolysis. One commenter stated that reporting energy consumption by hydrogen production sources is necessary to inform decarbonization strategies, *e.g.,* whether producing excessive amounts of green hydrogen may risk delaying fossil fuel retirement by diverting renewable energy from other uses. The commenter recommended a threshold for these facilities based on energy input. The commenter added that any hydrogen production facilities using carbon capture and sequestration technology should be required to report in all instances, as emissions data and energy consumption data from these facilities will be highly relevant to future regulatory action.

Multiple commenters commented on the EPA's request for comment regarding removing the threshold for the hydrogen production source category. One commenter strongly urged the EPA to make subpart P an ''all-in'' subpart to ensure all hydrogen production facilities are covered by reporting requirements, including the requirements proposed to report purchased energy consumption under proposed subpart B to part 98. The commenter pointed to hydrogen electrolysis facilities that may consume very large amounts of grid electricity that could have significant upstream emissions impacts; the commenter stated that many or most of these facilities will already be tracking the attributes of the energy they consume to qualify for Federal incentives and investment, and will therefore have this information readily available. The commenter stressed that understanding this information and the lifecycle emissions of hydrogen production will be critical to informing future actions under the CAA. The commenter also supported a production-based reporting threshold to ensure reporting for high production facilities with lower direct emissions and suggested the production threshold should at least include at least the top 75 percent of production facilities. One commenter suggested a hydrogen production threshold of 5,000 mt/year. Another commenter recommended that the EPA should implement a threshold to limit the applicability of the subpart to larger hydrogen production facilities. One commenter opposed a hydrogen production threshold, and recommended that the EPA retain the existing emissions-based threshold of 25,000 $mtCO_2e$; the commenter suggested this would further incentivize the implementation of low GHG hydrogen manufacturing processes over higher emitting processes such as steam methane reformers.

Several commenters also opposed revisions that would remove the ability of sources to off-ramp. One commenter offered the following recommendations: (1) hydrogen production process units which produce hydrogen but emit no direct GHG emissions should become eligible to cease reporting starting January 1 of the following year after the cessation of direct GHG emitting activities associated with the process; (2) if the direct GHG emissions remain below 15,000 $mtCO_2e$ or between 15,000 and 25,000 $mtCO_2e$, reporting would be required for 3 or 5 years respectively, consistent with the existing off-ramp provisions; or (3) if the EPA establishes a hydrogen production threshold for reporting, then falling below the production threshold should be the trigger for cessation of reporting, either starting January 1 of the following year or on a parallel structure to the three and five year off-ramp emission thresholds. Two other commenters stated that the EPA ignores that the ''off-ramp'' is intended for entities that should no longer be subject to reporting requirements by virtue of the fact that their emissions fall below a reasonable threshold. One commenter stated that it is unclear how the EPA would have authority to continue to require reporting for these entities, and the commenters said that the EPA should justify excluding hydrogen production facilities from the off-ramp. The commenters added that the EPA could use other methods to collect this data, including proposing a separate standard addressing emissions from hydrogen production under CAA section 111.

Response: We agreed with commenters that the language regarding ''hydrogen gas sold as a product to other entities'' could cause confusion, as we intended to require non-merchant hydrogen production units to now report under subpart P. As such, we are finalizing, as proposed in the 2023 Supplemental Proposal, the language in 40 CFR 98.160(a) to focus on hydrogen gas production without referring to the disposition of the hydrogen produced. In the 2023 Supplemental Proposal, we also proposed to significantly revise § 98.160(b) and (c). The supplemental proposal revisions appear to address most of the commenter's suggested revisions, except that we are not including ''electrolysis'' in the list of types of transformations in 40 CFR 98.160(b) because we consider electrolysis as already included under ''. . . reaction, or other transformations of feedstocks.'' This is also supported by the inclusion of water electrolysis and brine electrolysis in the list of hydrogen production unit types in the proposed 40 CFR 98.166(b)(1)(i) (now 40 CFR 98.166(d)(1)). We agree with commenters that subpart P should be applicable to non-merchant facilities and are finalizing the proposed revisions.

The EPA has considered comments both supporting and not supporting changes related to the EPA's request for information regarding removing the emissions-based threshold or introducing an alternative production-based threshold for the hydrogen production source category, including options to require continued reporting from hydrogen production facilities by amending the emissions-based off-ramp provisions at 40 CFR 98.2(i)(1) and (2). The EPA did not propose or provide for review specific revisions to part 98 to expand the source category, beyond the inclusion of non-merchant facilities as discussed in section III.I.1. of this preamble. Therefore, we are not including any revisions to the threshold to subpart P or to the ability of hydrogen production facilities to off-ramp in this final rule. However, the EPA may further consider these comments and the information provided as we evaluate next steps concerning the collection of information from hydrogen production facilities and consider approaches to improving our understanding of hydrogen as a fuel source, including to inform any potential future rulemakings.

Comment: Three commenters did not support the requirement to report combustion from hydrogen production process units under subpart P in lieu of subpart C as proposed in 40 CFR 98.160(c). Two commenters stated that these units may not be metered separately from other combustion units located at an integrated facility, which would require additional metering to comply with subpart P reporting of combustion emissions directly associated with the hydrogen production process. These commenters stated that if combustion emissions directly associated with the hydrogen production process must be reported under subpart P, engineering estimations for fuel consumption should be allowed. One commenter recommended that EPA implement a threshold to limit the applicability of the subpart to larger hydrogen production facilities.

Response: Steam methane reforming (SMR) is an endothermic process, and heating and reheating of fuels and feedstocks to maintain reaction temperatures is an integral part of the steam methane reforming reaction. Therefore, subpart P has always required the reporting of ''fuels and feedstocks'' used in the hydrogen production unit and subpart C should only be used for ''. . . each stationary combustion unit other than hydrogen production process units'' (40 CFR 98.162(c)). We have long noted that the emissions from most SMR furnaces include a mixture of process and combustion emissions.[15] For more accurate comparison of CEMS measured emissions with those estimated using the mass balance method, we required reporting of the combustion emissions from the SMR furnace as part of the subpart P emissions. Our proposed revisions, therefore, were not a new requirement, but a further clarification of the existing requirements in subpart P, as we interpret them. Based on previous reviews of the emissions intensities from hydrogen production as compiled from subpart P reported data, we estimate that there are only a few facilities that do not include the SMR furnace or process heaters combustion emissions in their subpart P emission totals. To allow time for those facilities to measure fuel used in stationary combustion units associated with hydrogen production (*e.g.,* reforming furnaces and hydrogen production process unit heaters), we decided to include in this final rule a limited allowance for BAMM for those facilities that may still need to add appropriate monitoring equipment (as demonstrated through meeting the specified criteria in the final provision). We also note that subpart C units reporting under the common pipe reporting configuration at 40 CFR 98.36(c)(3) may use company records to subtract out the portion of the fuel diverted to other combustion unit(s) prior to performing the GHG emissions calculations for the group of units using the common pipe option. Regarding the recommendation to implement a threshold to limit applicability to larger hydrogen production facilities, we are not taking final action on any revisions to the threshold to subpart P, therefore, facilities with hydrogen production plants will continue to determine applicability to part 98 based on the existing requirements of 40 CFR 98.2(a). A facility that contains a source category listed in table A–4 to subpart A of part 98 (which includes hydrogen production) must report only if the estimated combined annual emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories in tables A–3 and table A–4 of part 98 are 25,000 mtCO$_2$e or more. Therefore, the applicability of the subpart is already limited to larger hydrogen production facilities.

Comment: One commenter stated that EPA's proposed mass balance equation under 40 CFR 98.163(d), equation P–4, requires further revision to ensure that it is accurate for refineries that have non-merchant hydrogen plants (such as those currently reporting under subpart Y). The commenter added that to ensure proper accounting, the variable ''$C_{\mathrm{offsite},n}$'' should be further revised to include language for non-merchant hydrogen plants as follows: ''Mass of carbon other than CO$_2$ or methanol collected from the hydrogen production

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[15] See, *e.g., https://ccdsupport.com/confluence/pages/viewpage.action?pageId=173080691.*

unit and transferred off site or reported elsewhere by the facility under this part, from company records for month n (metric tons carbon).''

Response: Following consideration of comments on similar proposed revisions in other subparts, as discussed in section III.K.2. of this preamble, we are not taking final action at this time on proposed amendments to equation P–4 to allow the subtraction of carbon contained in products other than CO_2 or methanol and the carbon contained in methanol from the carbon mass balance used to estimate CO_2 emissions. However, we acknowledge this concern and agree that an analogous scenario may also occur within a facility that contains a captive (non-merchant) hydrogen production process unit. For example, some hydrogen production processes may operate without the water-gas-shift reaction and produce a syngas of hydrogen and carbon monoxide. For merchant plants, this syngas would be sold as a product for use as a fuel or as a feedstock for chemical production process. For a non-merchant plant, the syngas may be used on-site as a fuel or feedstock rather than sold off-site as a product. If a captive hydrogen production unit produces syngas for use as a fuel for an on-site stationary combustion unit, for example, the rule as proposed would not have allowed the subtraction of the carbon in the syngas from the emissions from the hydrogen production unit, resulting in double counting the CO_2 emissions related to this carbon (from both the hydrogen production unit and from the stationary combustion source). Most refineries with captive hydrogen production units seek to produce hydrogen for use in their refining process units and, therefore, use the water-gas-shift reaction to make pure hydrogen rather than syngas. However, production of syngas is possible under some circumstances. Although we are not finalizing equation P–4 as proposed, because the rule currently requires the reporting of carbon other than CO_2 or methanol that is transferred off site, we have revised the reporting requirements to clarify that the reported value, for non-merchant hydrogen production facilities, should include the quantity of carbon other than CO_2 or methanol that is transferred to a separate process unit within the facility for which GHG emissions associated with this carbon are being reported under other provisions of part 98.

Comment: One commenter supported the separate reporting of hydrogen that is produced and hydrogen that is only purified, but requested that the EPA provide sufficient implementation time and allow for best available monitoring methods to be used until installation of necessary monitoring equipment could occur.

Another commenter was supportive of reporting steam consumption data (*i.e.,* annual net quantity of steam consumed). However, the commenter added that there may be situations where steam is sourced from equipment (*e.g.,* a stand-alone boiler) distinct from a waste heat boiler associated with the SMR process; the commenter stated the rule should allow for flexibility in how the steam production and consumption is measured and quantified, including the ability to utilize best available monitoring methods.

Other commenters opposed reporting steam consumption data. One commenter opposing the requirements stated it could result in duplicative reporting based on what is proposed to be reported under subpart B. Two commenters stated that the EPA failed to provide justification for the requirement. Two commenters stated that it may be necessary for the EPA to issue an additional supplemental notice of proposed rulemaking to take comment on any such justification.

Response: Subpart P only provides monitoring requirements for fuels and feedstocks, it does not specify monitoring requirements for other reported data, for example, ammonia and methanol production. There are often cases in part 98 where there are reporting elements, but not specific monitoring requirements. In such cases, company records, engineering estimates, and similar approaches may be used (in addition to direct measurement methods) to report these quantities. As such, there is no need for BAMM provisions related to additional reporting requirements that require separately reporting produced and purified hydrogen quantities and net steam consumption.

We also note that the subpart P requirement is process unit specific, which is not duplicative of the proposed subpart B facility- or subpart-level reporting requirements. We also disagree that we did not provide rationale for the proposed requirements. These requirements (as with many of the other proposed requirements for subpart P) are aimed to obtain better information to verify reported emissions. For example, if a facility is a net steam purchaser, some emissions resulting from activities that support the hydrogen production process may occur at the steam production site. Thus, knowing the net steam consumption may help explain why the emissions to production ratios for these facilities based on reported data do not fall within the expected ranges. Understanding this could result in less correspondence from the EPA to verify these facilities' reports and therefore reduce the burden to these facilities.

J. Subpart Q—Iron and Steel Production

We are finalizing the amendments to subpart Q of part 98 (Iron and Steel Production) as proposed. This section discusses the final revisions to subpart Q. The EPA received comments on the proposed requirements for subpart Q; see the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart Q. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the revisions to subpart Q as described in section VI. of this preamble.

1. Revisions To Improve the Quality of Data Collected for Subpart Q

The EPA is finalizing revisions to subpart Q, as proposed in the 2022 Data Quality Improvements Proposal, to enhance the quality and accuracy of the data collected. First, we are revising 40 CFR 98.176(g) for all unit types (taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, decarburization vessel, and direct reduction furnace) and all calculation methods (direct measurement using CEMS, carbon mass balance methodologies, or site-specific emission factors) to require that facilities report the type of unit, the annual production capacity, and the annual operating hours for each unit.

The EPA is also finalizing revisions to correct equation Q–5 in 40 CFR 98.173(b)(1)(v) to remove an error introduced into the equation in prior revisions (81 FR 89188, December 9, 2016). The final rule corrects the equation to remove an unnecessary fraction symbol. See section III.H.1. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these revisions and their supporting basis.

2. Revisions To Streamline and Improve Implementation for Subpart Q

The EPA is finalizing two revisions to subpart Q to streamline monitoring. First, we are revising 40 CFR

98.174(b)(2) to provide the option for facilities to determine the carbon content of process inputs and outputs by use of analyses provided by material recyclers that manage process outputs for sale or use by other industries. Material recyclers conduct testing on their inputs and products to provide to entities using the materials downstream, and therefore perform carbon content analyses using similar test methods and procedures as suppliers. The final revisions include a minor harmonizing change to 40 CFR 98.176(e)(2) to require reporters to indicate if the carbon content was determined from information supplied by a material recycler.

The EPA is also finalizing revisions to 40 CFR 98.174(b)(2) to incorporate a new test method, ASTM E415–17, *Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry* (2017), for carbon content analysis of low-alloy steel. The new method is incorporated by reference in 40 CFR 98.7 and 98.174(b)(2) for use for steel, as applicable. The addition of this alternative test method will provide additional flexibility for reporters. We are also finalizing one harmonizing change to the reporting requirements of 40 CFR 98.176(e)(2), to clarify that the carbon content analysis methods available to report are those methods listed in 40 CFR 98.174(b)(2). See section III.H.2. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these revisions and their supporting basis.

K. Subpart S—Lime Production

We are finalizing several amendments to subpart S of part 98 (Lime Production) as proposed. In some cases, we are finalizing the proposed amendments with revisions. Section III.K.1. of this preamble discusses the final revisions to subpart S. The EPA received several comments on the proposed subpart S revisions which are discussed in section III.K.2. of this preamble. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the revisions to subpart S, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart S

The EPA is finalizing several revisions to subpart S of part 98 (Lime Manufacturing) as proposed to improve the quality of the data collected from this subpart. First, we are finalizing the addition of reporting requirements for reporters using the CEMS methodology, in order to improve our understanding of source category emissions and our ability to verify reported data. The EPA is adding data elements under 40 CFR 98.196(a) to collect annual averages of the chemical composition input data on a facility-basis, including the annual arithmetic average calcium oxide content (mt CaO/mt tons lime) and magnesium oxide content (mt MgO/mt lime) for each type of lime produced, for each type of calcined lime byproduct and waste sold, and for each type of calcined lime byproduct and waste not sold. These data elements rely on an arithmetic average of the measurements rather than requiring reporters to weight by quantities produced in each month. Collecting average chemical composition data for CEMS facilities will provide the EPA the ability to develop a process emission estimation methodology for CEMS reporters, which can be used to verify the accuracy of the reported CEMS emission data.

The EPA is also finalizing additional data elements for reporters using the mass balance methodology (*i.e.,* reporters that comply using the requirements at 40 CFR 98.193(b)(2)). The final rule includes new data elements under 40 CFR 98.196(b) to collect the annual average results of the chemical composition analysis of all lime byproducts or wastes not sold (*e.g.,* a single facility average calcium oxide content calculated from the calcium oxide content of all lime byproduct types at the facility), and the annual quantity of all lime byproducts or wastes not sold (*e.g.,* a single facility total calculated as the sum of all quantities, in tons, of all lime byproducts at the facility not sold during the year). These amendments will allow the EPA to build verification checks for the actual inputs entered (*e.g.,* MgO content). Because the final data elements rely on annual averages of the chemical composition measurements and an annual quantity of all lime byproducts or wastes at the facility, they are distinct from the data entered into the EPA's verification software tool. Additional information on these revisions and their supporting basis may be found in section III.I. of the preamble to the 2022 Data Quality Improvements Proposal.

In the 2022 Data Quality Improvements Proposal, the EPA proposed to improve the methodology for calculation of annual CO_2 process emissions from lime production to account for CO_2 that is captured from lime kilns and used on-site. Specifically, we proposed to modify equation S–4 to subtract the CO_2 that is captured and used in on-site processes, with corresponding revisions to the recordkeeping requirements in 40 CFR 98.197(c) (to record the monthly amount of CO_2 from the lime manufacturing process that is captured for use in all on-site processes), minor amendments to the reporting elements in 40 CFR 98.196(b)(1) (to clarify reporting of annual net emissions), 40 CFR 98.196(b)(17) (to clarify reporters do not need to account for CO_2 that was not captured but was used on-site), and to clarify that reporters must account for CO_2 usage from all on-site processes, including for manufacture of other products, in the total annual amount of CO_2 captured. Following consideration of comments received, the EPA is not taking final action at this time on the proposed revisions to equation S–4, or the corresponding revisions to 40 CFR 98.196(b)(1) and 98.197(c). We are finalizing the clarifying revisions to 40 CFR 98.196(b)(17), as proposed. We are also finalizing an editorial correction to equation S–4 to add a missing equation symbol. See section III.K.2. of this preamble for additional information on related comments and the EPA's response.

2. Summary of Comments and Responses on Subpart S

This section summarizes the major comments and responses related to the proposed amendments to subpart S. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart S.

Comment: One commenter opposed the proposed modifications to equation S–4 requiring monthly subtraction of CO_2 used on-site, stating it would be considerably more burdensome for lime producers that currently track and report this usage on an annual basis. The commenter requested that the EPA continue to allow the annual reporting of CO_2 usage, and thus implement an annual subtraction from total process emissions from all lime kilns combined.

Response: The EPA proposed revisions to subparts G (Ammonia Manufacturing), P (Hydrogen Production), and S (Lime Manufacturing) that would have required monthly measurement of captured CO_2 used to manufacture other products on-site or non-CO_2 carbon sent off-site to external users. It would also have modified the subpart-level equations to require that these amounts be subtracted from the emissions total. However, the EPA needs additional time to consider these comments and whether a consistent approach across these three subparts should be required or whether there are circumstances where alternative approaches might be warranted. Therefore, the EPA is not taking final action on these proposed revisions to subparts G, P, and S for at this time but may consider implementing these or similar revisions in future rulemakings.

L. Subpart U—Miscellaneous Uses of Carbonate

The EPA is finalizing one minor change to subpart U of part 98 (Miscellaneous Uses of Carbonate). The revision in this final rule is a harmonizing change following review of comments received on proposed subpart ZZ to part 98 (Ceramics Manufacturing) (see section III.EE. of this preamble for additional information on the related comments and the EPA's response). We are revising the source category definition for subpart U at 40 CFR 98.210(b) to clarify that ceramics manufacturing is excluded from the source category. Section 98.210(b) excludes equipment that uses carbonates or carbonate-containing materials that are consumed in production of cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc. We are adding the text ''or ceramics'' to ensure that there is no duplicative reporting between subpart U and new subpart ZZ.

M. Subpart X—Petrochemical Production

We are finalizing several amendments to subpart X of part 98 (Petrochemical Production) as proposed. This section summarizes the final revisions to subpart X. The EPA received only minor comments on the proposed requirements for subpart X. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart X.

We are finalizing as proposed several amendments to subpart X to improve the quality of data reported and to clarify the calculation, recordkeeping, and reporting requirements. First, we are finalizing a clarification to the emissions calculation requirements for flares in 40 CFR 98.243(b)(3) and (d)(5) to cross-reference 40 CFR 98.253(b) of subpart Y; these revisions clarify that subpart X reporters are not required to report emissions from combustion of pilot gas and from gas released during startup, shutdown, and malfunction (SSM) events of <500,000 standard cubic feet (scf)/day that are excluded from equation Y–3.

Next, we are finalizing as proposed the addition of new reporting requirements intended to improve the quality of the data collected under the GHGRP. First, we are finalizing reporting a new data element in 40 CFR 98.246(b)(7) and (c)(3). For each flare that is reported under the CEMS and optional ethylene combustion methodologies, facilities must report the estimated fractions of the total CO_2, CH_4, and N_2O emissions from each flare that are due to combusting petrochemical off-gas. The final rule will allow the fractions attributed to each petrochemical process unit that routes emissions to the flare to be estimated using engineering judgment. This change will allow more accurate quantification of emissions both from individual petrochemical process units and from the industry sector as a whole. Next, the EPA is finalizing addition of a requirement in 40 CFR 98.246(c)(6) to report the names and annual quantity (in metric tons) of each product produced in each ethylene production process for emissions estimated using the optional ethylene combustion methodology; this improves consistency with the product reporting requirements under the CEMS and mass balance reporting options.

We are finalizing, as proposed, a number of amendments that are intended to remove redundant or overlapping requirements and to clarify the data to be reported, as follows:

- For facilities that use the mass balance approach, we are finalizing amendments to 40 CFR 98.246(a)(2) to remove the requirement to report feedstock and product names, which previously overlapped with reporting requirements in 40 CFR 98.246(a)(12) and (13).
- We are finalizing revisions to 40 CFR 98.246(a)(5) to clarify the petrochemical and product reporting requirements for integrated ethylene dichloride/vinyl chloride monomer (EDC/VCM) process units. The amendments clarify the rule for facilities with an integrated EDC/VCM process unit that withdraw small amounts of the EDC as a separate product stream. The final rule is revised at 40 CFR 98.246(a)(5) to specify that (1) the portion of the total amount of EDC produced that is an intermediate in the production of VCM may be either a measured quantity or an estimate; (2) the amount of EDC withdrawn from the process unit as a separate product (*i.e.,* the portion of EDC produced that is not utilized in the VCM production) is to be measured in accordance with 40 CFR 98.243(b)(2) or (3); and (3) the sum of the two values is to be reported under 40 CFR 98.246(a)(5) as the total quantity of EDC petrochemical from an integrated EDC/VCM process unit.
- We are finalizing a change in 40 CFR 98.246(a)(13) to clarify that the amount of EDC product to report from an integrated EDC/VCM process unit should be only the amount of EDC, if any, that is withdrawn from the integrated process unit and not used in the VCM production portion of the integrated process unit.
- For facilities that use CEMS, we are finalizing amendments to 40 CFR 98.246(b)(8) to clarify the reporting requirements for the amount of EDC petrochemical when using an integrated EDC/VCM process unit, by removing language related to considering the petrochemical process unit to be the entire integrated EDC/VCM process unit.
- For facilities that use the optional ethylene combustion methodology to determine emissions from ethylene production process units, we are finalizing revisions to 40 CFR 98.246(c)(4) to clarify that the names and annual quantities of feedstocks that must be reported will be limited to feedstocks that contain carbon.
- We are finalizing changes to 40 CFR 98.246(a)(15) to more clearly specify that molecular weight must be reported for gaseous feedstocks and products only when the quantity of the gaseous feedstock or product used in equation X–1 is in standard cubic feet; the molecular weight does not need to be reported when the quantity of the gaseous feedstock or product is in kilograms.

Additional information on the EPA's rationale for these revisions may be found in section III.K. of the preamble to the 2022 Data Quality Improvements Proposal.

We are also finalizing as proposed confidentiality determinations for new data elements resulting from the revisions to subpart X, as described in section VI. of this preamble.

N. Subpart Y—Petroleum Refineries

We are finalizing several amendments to subpart Y of part 98 (Petroleum Refineries) as proposed. This section summarizes the final revisions to subpart Y. The EPA received several comment letters on the proposed requirements for subpart Y. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart Y.

We are also finalizing as proposed confidentiality determinations for new data elements resulting from the revisions to subpart Y, as described in section VI. of this preamble.

1. Revisions To Improve the Quality of Data Collected for Subpart Y

The EPA is finalizing as proposed several amendments to subpart Y of part 98 to improve data collection, clarify rule requirements, and correct an error in the rule. First, we are finalizing amendments to the provisions for delayed coking units (DCU) to add reporting requirements for facilities using mass measurements from company records to estimate the amount of dry coke at the end of the coking cycle in 40 CFR 98.256(k)(6)(i) and (ii). These new paragraphs will require facilities to additionally report, for each DCU: (1) the internal height of the DCU vessel; and (2) the typical distance from the top of the DCU vessel to the top of the coke bed (*i.e.,* coke drum outage) at the end of the coking cycle (feet). These new elements will allow the EPA to estimate and verify the reported mass of dry coke at the end of the cooling cycle as well as the reported DCU emissions.

We are also finalizing revisions to equation Y–18b in 40 CFR 98.253(i)(2), to include a new variable ''f_{coke}'' to allow facilities that do not completely cover the coke bed with water prior to venting or draining to accurately estimate the mass of water in the drum. The ''f_{coke}'' variable is defined as the fraction of coke-filled bed that is covered by water at the end of the cooling cycle just prior to atmospheric venting or draining, where a value of one (1) represents cases where the coke is completely submerged in water. The second term in equation Y–18b represents the volume of coke in the drum, and is subtracted from the water-filled coke bed volume to determine the volume of water. We are also finalizing revisions to the equation terms ''M_{water}'' and ''H_{water}'' to add the phase ''or draining'' to specify that these parameters reflect the mass of water and the height of water, respectively, at the end of the cooling cycle just prior to atmospheric venting or draining. We are finalizing harmonizing revisions to the recordkeeping requirements at 40 CFR 98.257(b)(45) and (46) and a corresponding recordkeeping requirement at 40 CFR 98.257(b)(53).

To help clarify that the calculation methodologies in 40 CFR 98.253(c) and 98.253(e) are specific to coke burn-off emissions, we are finalizing the addition of ''from coke burn-off'' immediately after the first occurrence of ''emissions'' in the introductory text of 40 CFR 98.253(c) and 98.253(e).

We are also finalizing corrections to an inconsistency inadvertently introduced into subpart Y by amendments published on December 9, 2016 (81 FR 89188), which created an apparent inconsistency about whether to include or exclude SSM events less than 500,000 scf/day in equation Y–3. This final rule clarifies in 40 CFR 98.253(b) that SSM events less than 500,000 scf/day may be excluded, but only if reporters are using the calculation method in 40 CFR 98.253(b)(1)(iii). We are also finalizing revisions to remove the recordkeeping requirements in existing 40 CFR 98.257(b)(53) through (56) and to reserve 40 CFR 98.257(b)(54) through (56). These requirements should have been removed in the December 9, 2016 amendments, which removed the corresponding requirement in 40 CFR 98.253(j) to calculate CH_4 emissions from DCUs using the process vent method (equation Y–19). The EPA is also finalizing corrections to an erroneous cross-reference in 40 CFR 98.253(i)(5), which inaccurately defines the term ''M_{stream}'' in equation Y–18f for DCUs, to correct the cross-reference to § 98.253(i)(4) instead of § 98.253(i)(3). Additional information on the EPA's rationale for these revisions may be found in section III.L.1. of the preamble to the 2022 Data Quality Improvements Proposal.

The EPA is finalizing as proposed one additional revision to improve data quality from the 2023 Supplemental Proposal. Specifically, we are finalizing the addition of a requirement to report the capacity of each asphalt blowing unit, consistent with the existing reporting requirements for other emissions units under subpart Y. The final rule requires that facilities provide the maximum rated unit-level capacity of the asphalt blowing unit, measured in mt of asphalt per day, in 40 CFR 98.256(j)(2). Additional information on the EPA's rationale for these revisions may be found in section III.H. of the preamble to the 2023 Supplemental Proposal.

2. Revisions To Streamline and Improve Implementation for Subpart Y

The EPA is finalizing one change to subpart Y to streamline monitoring. We are finalizing an option for reporters to use mass spectrometer analyzers to determine gas composition and molecular weight without the use of a gas chromatograph. The final rule adds the inclusion of direct mass spectrometer analysis as an allowable gas composition method in 40 CFR 98.254(d). This change will allow reporters to use the same analyzers used for process control or for compliance with continuous sampling which are proposed to be provided under the National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR part 63, subpart CC), to comply with GHGRP requirements in subpart Y. Additional information on these revisions and their supporting basis may be found in section III.L.2. of the preamble to the 2022 Data Quality Improvements Proposal.

Consistent with changes we are finalizing to subpart P of part 98 (Hydrogen Production) from the 2023 Supplemental Proposal, we are finalizing revisions to remove references to non-merchant hydrogen production plants in 40 CFR 98.250(c) and to delete and reserve 40 CFR 98.252(i), 98.255(d), and 98.256(b). We are also finalizing as proposed revisions to remove references to coke calcining units in 40 CFR 98.250(c) and 98.257(b)(16) through (19) and to remove and reserve 40 CFR 98.252(e), 98.253(g), 98.254(h), 98.254(i), 98.256(i), and 98.257(b)(27) through (31). As proposed in the 2023 Supplemental Proposal, we are finalizing the addition of new subpart WW to part 98 (Coke Calciners), and these provisions are no longer necessary under subpart Y. Additional information on these revisions and their supporting basis may be found in section III.H. of the preamble to the 2023 Supplemental Proposal.

O. Subpart AA—Pulp and Paper Manufacturing

We are finalizing the amendments to subpart AA of part 98 (Pulp and Paper Manufacturing) as proposed. The EPA received no comments regarding the proposed revisions to subpart AA. Additional rationale for these amendments is available in the preamble to the 2023 Supplemental Proposal. The EPA is revising 40 CFR 98.273 to add a biogenic calculation methodology for estimation of CH_4, N_2O, and biogenic CO_2 emissions for units that combust biomass fuels (other than spent liquor solids) from table C–1 to subpart C of part 98 or that combust biomass fuels (other than spent liquor solids) with other fuels. We are also revising 40 CFR 98.276(a) to remove incorrect references to biogenic CH_4 and N_2O and correcting a typographical error at 40 CFR 98.277(d), as proposed. Additional rationale for these amendments is available in the preamble to the 2023 Supplemental Proposal.

P. Subpart BB—Silicon Carbide Production

We are finalizing the amendments to subpart BB of part 98 (Silicon Carbide Production) as proposed. The EPA received no comments regarding the proposed revisions to subpart BB. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal. The EPA is finalizing a reporting requirement at 40 CFR 98.286(c) such that if CH_4 abatement technology is used at silicon carbide production facilities, then facilities must report: (1) the type of CH_4 abatement technology used and the date of installation for each technology; (2) the CH_4 destruction efficiency (percent destruction) for each CH_4 abatement technology; and (3) the percentage of annual operating hours that CH_4 abatement technology was in use for all silicon carbide process units or production furnaces combined. For each CH_4 abatement technology, reporters must either use the manufacturer's specified destruction efficiency or the destruction efficiency determined via a performance test; if the destruction efficiency is determined via a performance test, reporters must also report the name of the test method that was used during the performance test. Following the initial annual report containing this information, reporters will not be required to resubmit this information unless the information changes during a subsequent reporting year, in which case, the reporter must update the information in the submitted annual report. The final revisions to subpart BB also add a recordkeeping requirement at 40 CFR 98.287(d) for facilities to maintain a copy of the reported information. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal. The EPA is also finalizing, as proposed, confidentiality determinations for the additional data elements to be reported as described in section VI. of this preamble.

Q. Subpart DD—Electrical Transmission and Distribution Equipment Use

We are finalizing several amendments to subpart DD of part 98 (Electrical Transmission and Distribution Equipment Use) as proposed. In some cases, we are finalizing the proposed amendments with revisions. Section III.Q.1. of this preamble discusses the final revisions to subpart DD. The EPA received several comments on the proposed subpart DD revisions which are discussed in section III.Q.2. of this preamble. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the final revisions to subpart DD, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart DD

This section summarizes the final amendments to subpart DD. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other final revisions to 40 CFR part 98, subpart DD can be found in this section and section III.Q.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal.

a. Revisions To Improve the Quality of Data Collected for Subpart DD

The EPA is finalizing several revisions to subpart DD to improve the quality of the data collected under this subpart. First, we are generally finalizing the proposed revisions to the calculation, monitoring, and reporting requirements of subpart DD to require reporting of additional F–GHGs, except insulating gases with weighted average GWPs less than or equal to one will remain excluded from reporting under subpart DD. These final amendments will help to account for use and emissions of replacements for SF_6, including fluorinated gas mixtures, with lower but still significant GWPs. We are revising 40 CFR 98.300(a) to redefine the source category to include equipment containing ''fluorinated GHGs (F–GHGs), including but not limited to sulfur-hexafluoride (SF_6) and perfluorocarbons (PFCs).'' These changes include:

- Revising the threshold determination in 40 CFR 98.301 by adding new equations DD–1 and equation DD–2 (see section III.Q.1.b. of this preamble).
- Revising the GHGs to report at 40 CFR 98.302 by adding a new equation DD–3, which is also used in the definition of ''reportable insulating gas,'' discussed below.
- Redesignating equation DD–1 as equation DD–4 at 40 CFR 98.303 and revising the equation to estimate emissions from all F–GHGs within the existing calculation methodology, including F–GHG mixtures. Equation DD–4 will maintain the facility-level mass balance approach of tracking and accounting for decreases, acquisitions, disbursements, and net increase in total nameplate capacity for the facility each year, but will apply the weight fraction of each F–GHG to determine the user emissions by gas. In the final rule, we are making two clarifications to equation DD–4 in addition to the revisions that were proposed. These are discussed further below.
- Updating the monitoring and quality assurance requirements at 40 CFR 98.304(b) to account for emissions from additional F–GHGs.
- To address references to F–GHGs and F–GHG mixtures, we are finalizing the term ''insulating gas'' which is defined as ''any fluorinated GHG or fluorinated GHG mixture, including but not limited to SF_6 and PFCs, that is used as an insulating and/or arc quenching gas in electrical equipment.''
- To clarify which insulating gases are subject to reporting requirements, we are adding the term ''reportable insulating gas,'' which is defined as ''an insulating gas whose GWP, as calculated in equation DD–3, is greater than one. A fluorinated GHG that makes up either part or all of a reportable insulating gas is considered to be a component of the reportable insulating gas.'' In many though not all cases, we are replacing occurrences of the proposed phrase ''fluorinated GHGs, including PFCs and SF_6'' with ''fluorinated GHGs that are components of reportable insulating gases.''
- Adding harmonizing requirements to the term ''facility'' in the definitions section at 40 CFR 98.308 and the requirements at 40 CFR 98.302, 98.305, and 98.306 to require reporters to account for the mass of each F–GHG for each electric power system.

As noted above, following consideration of comments received, the EPA is revising these requirements from proposal to continue to exclude insulating gases with weighted average 100-year GWPs of less than one. Based on a review of the subpart DD data submitted to date, the EPA has concluded that excluding insulating gases with GWPs of less than one from reporting under subpart DD will have little effect on the accuracy or completeness of the GWP-weighted totals reported under subpart DD or under the GHGRP generally at this time, and will decrease the reporting burden for facilities. See section III.Q.2. of this preamble for a summary of the related comments and the EPA's response.

Also as noted above, we are making two clarifications to equation DD–4 in addition to the revisions that were proposed. First, to account for the possibility that the same fluorinated GHG could be a component of multiple reportable insulating gases, we are inserting a summation sign at the beginning of the right side of equation DD–4 to ensure that emissions of each fluorinated GHG ''i'' are summed across all reportable insulating gases ''j.'' Second, upon further consideration of equation DD–4 and its relationship to the newly defined terms ''new equipment'' and ''retiring equipment,'' we are modifying the terms for acquisitions and disbursements of reportable insulating gas j to account for acquisitions and disbursements of reportable insulating gas that are linked to the acquisition or sale of all or part of an electric power system. These include acquisitions or disbursements of reportable insulating gas inside equipment that is transferred while in use, acquisitions or disbursements of insulating gas inside equipment that is transferred from or to entities other than electrical equipment manufacturers and distributors while the equipment is not in use, and acquisitions or disbursements of insulating gas in bulk from or to entities other than chemical producers or distributors. Accounting for these acquisitions and disbursements in equation DD–4 ensures that the terms for acquisitions and disbursements of reportable insulating gas will be mathematically consistent with other terms in the equation, including the terms for the net increase in total nameplate capacity and the quantity of gas stored in containers at the end of the year. The term for the net increase in the total nameplate capacity will reflect the new definitions of ''new equipment'' and ''retiring equipment,'' which include transfers of equipment while in use. Similarly, the term for the quantity of reportable insulating gas stored in containers at the end of the year will reflect acquisitions or disbursements of reportable insulating gas stored in containers from or to all other entities, including other electric power systems. If these acquisitions or disbursements of gas in equipment or in bulk are not accounted for in the equation, the result will be incorrect. The revised terms are consistent with the definitions of ''new'' and ''retired'' in their treatment of hermetically sealed pressure equipment, with such equipment being included in terms related to equipment that is transferred while not in use, but excluded from terms related to equipment that is transferred while in use. We are also making harmonizing changes to the reporting requirements at 40 CFR 98.306, revising paragraphs (f), (g), and (i) (to be redesignated as paragraph (k)), and adding paragraphs (i), (n), and (o). These harmonizing revisions do not substantively change the reporting requirements as proposed and therefore would not substantively impact the burden to reporters.

With minor changes, we are finalizing the proposed requirements in 40 CFR 98.303(b) for users of electrical equipment to follow certain procedures when they elect to measure the nameplate capacities (in units of mass of insulating gas) of new and retiring equipment rather than relying on the rated nameplate capacities provided by equipment manufacturers. As proposed, this option will be available only for closed pressure equipment with a voltage capacity greater than 38 kilovolts (kV), not for hermetically sealed pressure equipment or smaller closed-pressure equipment. These procedures are intended to ensure that the nameplate capacity values that equipment users measure match the full and proper charges of insulating gas in the electrical equipment. These procedures are similar to and compatible with the procedures for measuring nameplate capacity adopted by the California Air Resources Board (CARB) in its Regulation for Reducing Greenhouse Gas Emissions from Gas Insulated Switchgear.[16]

Specifically, electrical equipment users electing to measure the nameplate capacities of any new or retiring equipment will be required at 40 CFR 98.303(b)(1) to measure the nameplate capacities of all eligible new and retiring equipment in that year and in all subsequent years. For each piece of equipment, the electrical equipment user will be required to calculate the difference between the user-measured and rated nameplate capacities, verifying that the rated nameplate capacity was the most recent available from the equipment manufacturer. Where a user-measured nameplate capacity differs from the rated nameplate capacity by two percent or more, the electrical equipment user will be required at 40 CFR 98.303(b)(2) to adopt the user-measured nameplate capacity for that equipment for the remainder of the equipment's life. Where a user-measured nameplate capacity differs from the rated nameplate capacity by less than two percent, the electrical equipment user will have the option at 40 CFR 98.303(b)(3) to adopt the user-measured nameplate capacity, but if they chose to do so, they must adopt the user-measured nameplate capacities for all new and retiring equipment whose user-measured nameplate capacity differed from the rated nameplate capacity by less than two percent.

With minor changes, the EPA is finalizing the proposed requirements at 40 CFR 98.303(b)(4) and (5) for when electrical equipment users measure the nameplate capacity of new equipment that they install and for when they measure the nameplate capacity of retiring equipment. These final requirements ensure that electrical equipment users:

- Correctly account for the mass of insulating gas contained in new equipment upon delivery from the manufacturer (*i.e.,* the holding charge), and correctly account for the mass of insulating gas contained in equipment upon retirement, measuring the actual temperature-adjusted pressure and comparing that to the temperature-adjusted pressure that reflects the correct filling density of that equipment.
- Use flowmeters or weigh scales that meet certain accuracy and precision requirements to measure the mass of insulating gas added to or recovered from the equipment;
- Use pressure-temperature charts and pressure gauges and thermometers that meet certain accuracy and precision requirements to fill equipment to the density specified by the equipment manufacturer or to recover the insulating gas from the equipment to the correct blank-off pressure, allowing appropriate time for temperature equilibration; and
- Ensure that insulating gas remaining in the equipment, hoses and gas carts is correctly accounted for.

After consideration of comments, we are including a requirement to follow the procedure specified by the equipment manufacturer to ensure that the measured temperature accurately reflects the temperature of the insulating gas, *e.g.,* by measuring the insulating gas pressure and vessel temperature after allowing appropriate time for the temperature of the transferred gas to equilibrate with the vessel temperature. Also after consideration of comments, we are (1) adding a requirement that facilities that use flow meters to measure the mass of insulating gas added to new equipment must keep the

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[16] See *https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2020/sf6/fro.pdf.*

mass flow rate within the range specified by the flowmeter manufacturer, and (2) not finalizing the option to use mass flowmeters to measure the mass of the insulating gas recovered from equipment. We are making both changes because the accuracy and precision of flowmeters can decrease significantly when the mass flow rate declines below the minimum specified by the flow meter manufacturer for accurate and precise measurements.

As proposed, we are allowing equipment users to account for any leakage from the equipment using one of two approaches. In both approaches, users must measure the temperature-compensated pressure of the equipment before they remove the insulating gas from that equipment and compare the measured temperature-compensated pressure to the temperature-compensated pressure corresponding to the full and proper charge of the equipment (the design operating pressure). If the measured temperature-compensated pressure is different from the temperature-compensated pressure corresponding to the full and proper charge of the equipment, the equipment user may either (1) add or remove insulating gas to or from the equipment until the equipment reaches its full and proper charge; recover the gas until the equipment reached a pressure of 0.068 pounds per square inch, absolute (psia) (3.5 Torr) or less; and weigh the recovered gas (charge adjustment approach), or (2) if (a) the starting pressure of the equipment is between its temperature-compensated design operating pressure and five (5) pounds per square inch (psi) below that pressure, and (b) the insulating gas is recovered to a pressure no higher than 5 psia (259 Torr),[17] recover the gas that was already in the equipment; weigh it; and account mathematically for the difference between the quantity of gas recovered from the equipment and the full and proper charge (mathematical adjustment approach, equation DD–5).

In the final rule, we are allowing use of the mathematical adjustment approach in somewhat more limited circumstances than proposed. We proposed that to use the mathematical adjustment approach to calculate the nameplate capacity, facilities would need to recover a quantity of insulating gas equivalent to at least 90 percent of the full manufacturer-rated nameplate capacity of the equipment, which would have provided more flexibility on the starting and ending pressures of the equipment during the recovery process. The proposed requirement was based on an analysis of the proposed accuracies and precisions of measuring devices and their impacts on the accuracy and precision of the mathematical adjustment approach, which indicated that 90 percent of the gas must be recovered to limit the uncertainty of the calculation to below 2 percent. We also recognized that departures from the ideal gas law could result in additional, systematic errors in the mathematical adjustment approach and therefore requested comment on the option of adding compressibility factors, which account for these departures, to equation DD–5 (proposed as equation DD–4). Such compressibility factors are not constant but are functions of the pressure and temperature of the insulating gas based on an equation of state specific to that insulating gas. We did not receive any comment on this option, and after considering the matter further, we believe that performing calculations using compressibility factors would prove too complex to implement in the field to obtain accurate nameplate capacity values. Without compressibility factors, departures of the insulating gas from the ideal gas law limit the reliability of the mathematical adjustment approach except within the ranges of starting and ending pressures described above. Consequently, we are finalizing the mathematical adjustment method as proposed but are restricting its use to the specified ranges of starting and ending pressures. Under these circumstances, any systematic errors in the mathematical adjustment approach are generally expected to fall below 0.5 percent, leading to maximum total errors (accounting for both departures from the ideal gas law and limits on the accuracy and precision of measuring devices) of approximately two percent. (For more discussion of this issue, see ‘‘Update to the Technical Support for Proposed Revisions to Subpart DD, Electrical Transmission and Distribution Equipment Use,’’ included in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424).

Given these restrictions, the mathematical adjustment approach cannot be used to calculate the nameplate capacity of equipment that cannot have the insulating gas inside of it recovered below atmospheric pressure. However, as noted above, the approach can still be used for situations where the blank-off pressure of a gas cart is above 3.5 Torr (0.068 psia) but below 5 psia and/or where the starting pressure of the electrical equipment is no more than 5 psi lower than its temperature-compensated design operating pressure. (Note that equipment whose starting pressure is above the temperature-compensated design operating pressure will need to have the excess gas recovered until it reaches the design operating pressure, at which point the nameplate capacity measurement can begin.)

We are finalizing as proposed requirements at 40 CFR 98.303(b)(6) that allow users to measure the nameplate capacity of electrical equipment earlier during maintenance activities that require opening the gas compartment. The equipment user will still be required to follow the measurement procedures required for retiring equipment at 40 CFR 98.303(b)(5) to measure the nameplate capacity, and the measured nameplate capacity must be recorded, but will not be used in equation DD–3 until that equipment is actually retired.

We are finalizing as proposed requirements at 40 CFR 98.303(b)(7) and (8) to require that, where the electrical equipment user is adopting the user-measured nameplate capacity, the user must affix a revised nameplate capacity label showing the revised nameplate value and the year the nameplate capacity adjustment process was performed to the device by the end of the calendar year in which the process was completed. For each piece of electrical equipment whose nameplate capacity is adjusted during the reporting year, the revised nameplate capacity value must be used in all rule provisions wherein the nameplate capacity is required to be recorded, reported, or used in a calculation.

To ensure that the mass balance method is based on consistent nameplate capacity values throughout the life of the equipment, we are finalizing at 40 CFR 98.303(b)(9) that electrical equipment users are allowed to measure and revise the nameplate capacity value of any given piece of equipment only once, unless the nameplate capacity itself is likely to have changed due to changes to the equipment (*e.g.,* replacement of the equipment bushings).

To help ensure that electrical equipment users obtain accurate measurements of their equipment's nameplate capacities, we are finalizing requirements at 40 CR 98.303(b)(10) that

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[17] While the mathematical adjustment approach is expected to yield accurate results if the final pressure is 5 psia or less, facilities are encouraged to recover the insulating gas until they reach the blank-off pressure of the gas cart, which is generally expected to fall below 5 psia. Note that where the final pressure is equal to or less than 0.068 psia, the gas remaining in the equipment is estimated to account for a negligible share of the total and therefore facilities are not required to use the Mathematical Adjustment Method to account for it.

electrical equipment users must use measurement devices that meet the following accuracy and precision requirements when they measure the nameplate capacities of new and retiring equipment:

- Flow meters must be certified by the manufacturer to be accurate and precise to within one percent of the largest value that the flow meter can, according to the manufacturer's specifications, accurately record.
- Pressure gauges must be certified by the manufacturer to be accurate and precise to within 0.5 percent of the largest value that the gauge can, according to the manufacturer's specifications, accurately record.
- Temperature gauges must be certified by the manufacturer to be accurate and precise to within ±1.0 °F; and
- Scales must be certified by the manufacturer to be accurate and precise to within one percent of the true weight.

Additional information on these revisions and their supporting basis may be found in section III.N.1. of the preamble to the 2022 Data Quality Improvements Proposal.

We are finalizing at 40 CFR 98.306(r) and (s) (proposed as 40 CFR 98.306(o) and (p)) requirements for equipment users who measure and adopt nameplate capacity values to report the total rated and measured nameplate capacities across all the equipment whose nameplate capacities were measured and for which the measured nameplate capacities have been adopted in that year.

We are finalizing requirements in 40 CFR 98.307(b) as proposed for equipment users to keep records of certain identifying information for each piece of equipment for which they measure the nameplate capacity: the rated and measured nameplate capacities, the date of the nameplate capacity measurement, the measurements and calculations used to obtain the measured nameplate capacity (including the temperature-pressure curve and/or other information used to derive the initial and final temperature adjusted pressures of the equipment), and whether or not the measured nameplate capacity value was adopted for that piece of equipment.

To clarify the mass balance methodology in 40 CFR 98.303, we are adding definitions for ''energized,'' ''new equipment,'' and ''retired equipment,'' at 40 CFR 98.308 as proposed. We are finalizing the definition of ''energized'' as proposed to mean ''connected through busbars or cables to an electrical power system or fully-charged, ready for service, and being prepared for connection to the electrical power system. Energized equipment does not include spare gas insulated equipment (including hermetically-sealed pressure switchgear) in storage that has been acquired by the facility, and is intended for use by the facility, but that is not being used or prepared for connection to the electrical power system.'' The final definition more clearly designates what equipment is considered to be installed and functioning as opposed to being in storage.

With two minor changes, we are finalizing the proposed definition for ''new equipment.'' ''New equipment'' is defined as ''either (1) any gas insulated equipment, including hermetically-sealed pressure switchgear, that is not energized at the beginning of the reporting year but is energized at the end of the reporting year, or (2) any gas insulated equipment other than hermetically-sealed pressure switchgear that has been transferred while in use, meaning it has been added to the facility's inventory without being taken out of active service (*e.g.,* when the equipment is sold to or acquired by the facility while remaining in place and continuing operation).'' Similarly, we are finalizing the definition for ''retired equipment'' with two minor changes. ''Retired Equipment'' is defined as ''either (1) any gas insulated equipment, including hermetically-sealed pressure switchgear, that is energized at the beginning of the reporting year but is not energized at the end of the reporting year, or (2) any gas insulated equipment other than hermetically-sealed pressure switchgear that has been transferred while in use, meaning it has been removed from the facility's inventory without being taken out of active service (*e.g.,* when the equipment is acquired by a new facility while remaining in place and continuing operation).'' The proposed definitions both included two sentences, where the first sentence specified that the equipment changed from ''not energized'' to ''energized'' (or vice versa), and the second sentence preceded the phrase ''that has been transferred while in use'' with ''This includes.'' Upon review of the proposed definitions, we realized that they could lead to confusion because equipment that is transferred while in use does not change from ''not energized'' to ''energized'' or vice versa, and therefore cannot be ''included'' in the sets of equipment that change from ''not energized'' to ''energized'' or vice versa. We therefore replaced ''This includes'' with ''or.'' We also realized that including hermetically-sealed pressure switchgear in equipment that is transferred while in use would trigger requirements to inventory the acquired (new) or disbursed (retired) hermetically-sealed pressure switchgear for purposes of the mass balance calculation (equation DD–4) and the reporting requirements at 40 CFR 98.306(a)(2) and (4). We did not intend to trigger these requirements for hermetically sealed pressure equipment that is transferred during use. Such requirements would be inconsistent with the intent and effect of the current provision at 40 CFR 98.306(a)(1), which excludes existing hermetically-sealed pressure switchgear from the requirement to report the existing nameplate capacity total at the beginning of the year. We therefore excepted hermetically sealed switchgear from equipment that is transferred while in use in both definitions. With these minor changes, the definitions clarify how the terms ''new'' and ''retired'' should be interpreted for purposes of equation DD–3.

b. Revisions To Streamline and Improve Implementation for Subpart DD

The EPA is finalizing several revisions to subpart DD to streamline requirements. First, we are revising the applicability threshold of subpart DD at 40 CFR 98.301 largely as proposed, in order to align with revisions to include additional F–GHGs in subpart DD. However, as discussed above, insulating gases with weighted average GWPs less than or equal to 1 will remain excluded from reporting under subpart DD. We are replacing the existing nameplate capacity threshold with an emissions threshold of 25,000 $mtCO_2e$ per year of F–GHGs that are components of reportable insulating gases (*i.e.,* insulating gases whose weighted average GWPs, as calculated in equation DD–3, are greater than one (1)). To calculate their F–GHG emissions for comparison with the threshold, electrical equipment users will use one of two new equations finalized in subpart DD at 40 CFR 98.301, equations DD–1 and DD–2. The equations explicitly include not only the nameplate capacity of the equipment but also an updated default emission factor and the GWP of each insulating gas.

We are also finalizing revisions to the existing calculation, monitoring, and reporting requirements of subpart DD to require reporting of additional F–GHGs beyond SF_6 and PFCs that are components of reportable insulating gases. The new equations DD–1 and DD–2 that we are finalizing for the applicability threshold require potential reporters to account for the total nameplate capacity of all equipment containing reportable insulating gases (located on-site and/or under common ownership or control), including equipment containing F–GHG mixtures, and multiply by the weight fraction of each F–GHG (for gas mixtures), the GWP for each F–GHG, and an emission factor of 0.10 (representing an emission rate of 10 percent).

We are finalizing harmonizing changes in multiple sections of subpart DD to renumber equation DD–1 and maintain cross-references to the equation. We are also finalizing revisions to the existing threshold in 40 CFR 98.301 and table A–3 to subpart A (General Provisions). Additional information on these revisions and their supporting basis may be found in section III.N.2. of the preamble to the 2022 Data Quality Improvements Proposal.

Finally, we are removing an outdated monitoring provision at 40 CFR 98.304(a), which reserves a prior requirement for use of BAMM that applied solely for RY2011.

2. Summary of Comments and Responses on Subpart DD

This section summarizes the major comments and responses related to the proposed amendments to subpart DD. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart DD.

a. Comments on Revisions To Improve the Quality of Data Collected for Subpart DD

Comment: One commenter asked for clarification regarding whether the equipment user needs to account for insulating gas remaining inside gas-insulated equipment (GIE) that are transferred to another entity (vendor) for repair or salvage. The commenter asserted that since the equipment is leaving the inventory with gas inside, it should be counted as both retired equipment and a gas disbursement. The commenter suggested the ''Disbursements'' term in equation DD–3 be modified to include similar language to the ''Acquisitions'' term, to clarify that gas inside equipment that is transferred to another entity for repair or salvage, in addition to equipment that is sold, counts as a disbursement.

Response: The EPA agrees with the commenter and is revising the ''Disbursements'' term in equation DD–3 (being finalized as equation DD–4) to account for gas ''transferred'' as well as ''sold'' to ''other entities.'' As discussed in section III.Q.1. of this preamble, we are making a number of clarifications to the ''Acquisitions'' and ''Disbursements'' terms in equation DD–4 to accommodate the full range of possible acquisitions and disbursements by electric power systems, which will improve the accuracy and completeness of equation DD–4 and the associated reporting and recordkeeping requirements.

Comment: One commenter suggested that the EPA revise the nameplate capacity adjustment text as follows: first, to remove the word ''covered'' prior to ''insulating gas'' in 40 CFR 98.303(b)(4)(ii)(A), since ''covered'' is not included in the EPA's definition of insulating gas.

Response: The EPA agrees with the commenter and is revising 40 CFR 98.303(b)(4)(ii)(A) as suggested to reflect the language which is used in the definitions and to minimize confusion. As discussed in section III.Q.1. of this preamble, we are introducing the term ''reportable insulating gas'' to distinguish between insulating gas that is included in subpart DD (''reportable'') because it has a weighted average GWP greater than 1 and insulating gas that is not reportable because it has a weighted average GWP of 1 or less.

Comment: Two commenters suggested the EPA change the language in 40 CFR 98.303(b)(5)(ii), which was proposed as a requirement to ''convert the initial system pressure to a temperature-compensated initial system pressure by using the temperature/pressure curve for that insulating gas.'' The commenters stated that the temperature/pressure curve is not intended for conversions of initial system pressure to temperature-compensated pressure. The commenters suggested that the requirement should be to compare the measured initial system pressure and vessel temperature to the equipment manufacturer's temperature-pressure curve specific for the equipment to confirm the equipment is at the proper operating pressure, prior to recovery of the insulating gas. One commenter recommended two options for measuring initial gas pressure: (1) use external pressure and temperature gauges according to 40 CFR 98.303(b)(5)(i); or (2) if an integrated temperature-compensated gas pressure gauge was used for the initial gas fill and to monitor and maintain the gas at the proper operating pressure over the service life of the circuit breaker, use the same gauge to determine whether the circuit breaker is at the proper operating pressure.

Response: The EPA agrees with the commenters regarding the language at 40 CFR 98.303(b)(5)(ii) and is finalizing the requirement as follows: ''Compare the initial system pressure and temperature to the equipment manufacturer's temperature/pressure curve for that equipment and insulating gas.'' Regarding allowing use of an integrated temperature-compensated gas pressure gauge, use of such a gauge is allowed if the gauge is certified by the gauge manufacturer to be accurate and precise to within 0.5 percent of the largest value that the gauge can, according to the manufacturer's specifications, accurately record. It is EPA's understanding that many gauges that are built into the electrical equipment do not meet these accuracy and precision requirements. However, if they do, the rule does not prohibit their use in nameplate capacity measurements.

Comment: One commenter objected to the proposed requirement to recover the insulating gas to a blank-off pressure not greater than 3.5 Torr during the nameplate capacity measurement. The commenter noted that not all facilities own gas carts capable of reaching 3.5 Torr, and, for some GIE, that level of pressure is not necessary for an accurate reading. The commenter recommended that the GIE recovery be performed to allow for 99.1 percent or greater recovery of the insulating gas.

Response: As discussed above, the EPA is finalizing a requirement that facilities measuring the nameplate capacity of their equipment recover the gas to a pressure of at most 5 psia (258.6 Torr). This will accommodate gas carts that are not capable of reaching 3.5 Torr. To ensure that the gas remaining in the equipment at pressures above 3.5 Torr is accounted for, facilities that recover the gas to a pressure between 5 psia and 3.5 Torr will be required to use the mathematical adjustment approach (equation DD–5) to calculate the full nameplate capacity. As discussed in the preamble to the proposed rule, the EPA estimates that 0.1 percent of the full and proper charge of insulating gas would remain in the equipment at 3.5 Torr (assuming that a full and proper charge has a pressure of 3800 Torr), a negligible fraction. However, the fraction of gas remaining after recovery of 99.1 percent of the gas, 0.9%, is not negligible, but represents a significant systematic underestimate compared to the 2% tolerance for nameplate capacity measurements. Since it is straightforward to correct for this systematic underestimate by using the mathematical adjustment approach, we are requiring use of equation DD–5 in such situations.

Comment: One commenter representing manufacturers of electrical equipment recommended that after insulating gas was added to a piece of electrical equipment, facilities should allow at least 24 hours to allow the gas to condition itself to its container in order to confirm the correct density has been met.

Response: The EPA is adding a requirement to 40 CFR 98.303(b)(4)(ii) that facilities follow the procedure specified by the electrical equipment manufacturer to ensure that the measured temperature accurately reflects the temperature of the insulating gas, *e.g.,* by measuring the insulating gas pressure and vessel temperature after allowing appropriate time for the temperature of the transferred gas to equilibrate with the vessel temperature. This allows for the possibility that some electrical equipment, *e.g.,* electrical equipment with smaller charge sizes, may require less than 24 hours for the insulating gas temperature to equilibrate with the temperature of the vessel. Because achieving the correct density of the insulating gas in the equipment is important to the proper functioning of the equipment, the guidance provided by the equipment manufacturer should be sufficient to ensure that the appropriate density is achieved for purposes of the nameplate capacity measurement.

Comment: Commenters representing electrical equipment users and manufacturers provided input on the use of mass flow meters to measure the nameplate capacities of new and retiring electrical equipment. One commenter provided recommended edits to the proposed text to add requirements to ensure that a minimum gas flow is maintained while measuring the mass of insulating gas being added to new equipment. The commenter stated that to ensure that the flowmeter was properly configured for its application, the maximum and minimum flow rates of the meter, as well as the displacement of the pumps and compressors on the gas cart being used, must be taken into consideration. The commenter added that, in general, mass flow meters designed for high flow applications will not be suitable for low flow conditions and meters designed for low flow applications will not be suitable for high flow conditions. This commenter also recommended adding the use of an in-calibration cylinder scale as an alternative option for measuring the gas transferred during the equipment filling process. Two commenters recommended removing the option to use a mass flow meter to measure the mass of insulating gas recovered from retiring equipment due to the potential for errors when a mass flow meter is used in this process. The commenters stated that use of a mass flow meter to measure the insulating gas recovered is not recommended since a mass flow meter does not accurately measure gas at low flow rates. Instead, the commenters recommended that the gas container weighing method should be used to accurately measure the total weight of insulating gas recovered from the equipment. One commenter added that the process of weighing all gas removed from a GIE and transferred into a cylinder includes weighing all the gas trapped in hoses and in gas cart, which would not be accounted for by the flow meter; the commenter pointed out that the gas (trapped in hoses and in the gas cart) would need to be moved into cylinders to be accurately weighed with a cylinder scale.

Response: After consideration of these comments, the EPA is finalizing the proposed provisions for measuring the nameplate capacities of new and retiring equipment with two changes. First, we are requiring that facilities that use mass flow meters to measure the mass of insulating gas added to new equipment must keep the mass flow rate within the range specified by the mass flow meter manufacturer to assure an accurate and precise mass flow meter reading. Second, we are removing the option to use mass flow meters to measure the quantity of gas recovered from retiring equipment. We have analyzed the impact of the uncertainty of flowmeters at low flow rates on overall nameplate capacity measurements, and we have concluded that this impact may lead to large errors under some circumstances. As noted by the commenters, the relative error for flowmeters can increase when the flowmeter is used to measure mass flow rates below a certain fraction of the maximum full-scale value, and the mass flow rate will gradually decline as the insulating gas is transferred from the container to the equipment or vice versa, reducing the density of the gas inside the source vessel. For measuring the quantity of insulating gas added to new equipment, this issue can be addressed by requiring that the mass flow rate be kept within the range specified by the mass flow meter manufacturer, which can be accomplished by, *e.g.,* switching to a full container when the density of the insulating gas in the current container falls below the minimum level. However, for measuring the quantity of insulating gas recovered from retiring equipment, the insulating gas is being transferred from the equipment itself, and the recovery process therefore inevitably lowers the mass flow rate below the minimum level. For this reason, we are not taking final action on the option to use flowmeters to measure the quantity of insulating gas recovered from retiring equipment.

In our analysis of this issue, we reviewed our proposal at 40 CFR 98.303(b)(10) that mass flow meters must be accurate and precise to within one percent of the largest value that the flow meter can, according to the manufacturer's specifications, accurately record, *i.e.,* the maximum full-scale value. This means that the relative error of the flowmeter could rise hyperbolically from one percent of the measured value (when the measured value equals the maximum value) to much higher levels at lower flow rates, *e.g.,* 2 percent of the flow rate at half the maximum, 4 percent of the flow rate at one quarter of the maximum, 10 percent of the flow rate at one tenth the maximum, etc. These rising relative errors lead to overall errors in the mass flow measurement that are far above one percent. Even if the flow meter is accurate to within one percent of the measured value over a ten-fold range of flow rates, errors at lower flow rates can be significant. In an example provided to us by a company that provides insulating gas recovery equipment (gas carts) and insulating gas recovery services to electric power systems, the relative error of the measurement of the flow rate rose by a factor of five when the flow rate fell below 10 percent of the maximum full-scale value. If the error of a flowmeter climbed from 1 percent to 5 percent when the flow rate fell below 10 percent of the maximum full-scale value, the measurement of the total mass recovered would have a maximum uncertainty of 1.4 percent, which can result in overall errors above 2 percent in the nameplate capacity measurement as a whole (accounting also for the uncertainties of measured pressures, etc.).

Regarding one commenter's recommendation that we allow weigh scales to be used to measure the quantity of gas filled into new equipment, we are finalizing our proposal at 40 CFR 98.303(b)(4)(ii)(A) to allow use of weigh scales for this measurement.

Comment: Two commenters requested the EPA remove the term ''precise'' from proposed 40 CFR 98.303(b)(10). Both commenters stressed that accuracy is more important. One commenter stated that equipment certified to be accurate and precise may be difficult to find, and another additionally asserted there is little value in precision.

Response: In the final rule, we are finalizing as proposed the accuracy and precision requirements for gauges, flow meters, and weigh scales used to measure nameplate capacities. To obtain an accurate measurement of the nameplate capacity of a piece of equipment, measurement devices must be both accurate and precise. As discussed in the technical support document for the proposed rule,[18] the term ''accurate'' indicates that multiple measurements will yield an average that is near the true value, while the term ''precise'' indicates that multiple measurements will yield consistent results. A measurement device that is accurate without being precise may show inconsistent results from measurement to measurement, and these individual inconsistent results may be significantly different from the true value even if their average is not. Since measurements of nameplate capacity are generally expected to be taken only once for a particular piece of equipment, the devices on which the individual measurements are taken must be both accurate and precise for the measurements to yield results that are near the true values.

Comment: One commenter suggested redefining the definition of ''insulating gas'' to including any gas with a GWP greater than one (1) and not any fluorinated GHG or fluorinated GHG mixture. The commenter urged that the proposed definition ignores other potential gases that may come onto the market that are not fluorinated but still have a GWP. The commenter stated that defining insulating gas to include any gas with a GWP greater than 1 used as an insulating gas and/or arc quenching gas in electrical equipment would mirror the threshold implemented by the California Air Resources Board and would provide consistency for reporters across Federal and State reporting rules.

Response: In the final rule, the EPA is not requiring electric power systems to track or report emissions of insulating gases with weighted average 100-year GWPs of one or less. Based on a review of the subpart DD data submitted to date, the EPA has concluded that excluding insulating gases with weighted average GWPs of one or less from reporting under subpart DD will have little effect on the accuracy or completeness of the GWP-weighted totals reported under subpart DD or under the GHGRP generally. Between 2011 and 2021, the highest emitting facilities reporting under subpart DD reported SF_6 emissions ranging from 8 to 23 mt (unweighted) or 190,000 to 540,000 $mtCO_2e$. Over the same period, total emissions across all facilities have ranged from 96 to 171 mt (unweighted) or 2.3 to 4.1 million $mtCO_2e$. At GWPs of one, these weighted totals would be equivalent to the unweighted quantities reported, which constitute approximately 0.004% (1/23,500) of the GWP-weighted totals. This does not account for the fact that for the first few years it is sold, equipment containing insulating gases with weighted average GWPs of one or less will make up a small fraction of the total nameplate capacity of the electrical equipment in use. (Electrical equipment has a lifetime of about 40 years, so only a small fraction of the total stock of equipment is retired and replaced each year.) Even in a worst-case scenario where the annual emission rate of the equipment containing a very low-GWP insulating gas was assumed to equal the total nameplate capacity of all the equipment installed (implying an emission rate of 100 percent, higher than any ever reported under the GHGRP), the total GWP-weighted emissions reported under subpart DD would be considerably smaller than those reported under any other subpart: total unweighted nameplate capacities reported across all facilities to date have ranged between 4,847 and 6,996 mt. At GWPs of 1, these totals would fall under the 15,000 and 25,000 $mtCO_2e$ quantities below which individual facilities are eventually allowed to exit the program under the off-ramp provisions, as applicable.

To monitor trends in the replacement of SF_6 by insulating gases with weighted average GWPs less than one, the EPA will continue to track supplies of such insulating gases under subparts OO and QQ and will track deliveries of such insulating gases in equipment or containers under subpart SS.

b. Comments on Revisions To Streamline and Improve Implementation for Subpart DD

Comment: One commenter supported the proposed threshold for subpart DD but wanted the EPA to clarify that reporters that do not think they will fall below the revised reporting threshold or are not otherwise using F–GHGs other than SF_6 do not need to recalculate their emissions to show they must report.

Response: The applicability threshold is for determining whether entities must initially begin reporting to the GHGRP. Facilities that have reported have calculated their emissions more precisely using the mass balance approach. If those calculations have shown that they are eligible to exit the program under the off-ramp provisions of subpart A of part 98 (40 CFR 98.2(i)), they do not need to report again unless facility emissions exceed 25,000 $mtCO_2e$. On the other hand, if the calculations have shown that the facility does not meet the existing off-ramp conditions to exit the program, they must continue reporting regardless of the results of the threshold calculation at 40 CFR 98.301.

R. Subpart FF—Underground Coal Mines

We are finalizing the amendments to subpart FF of part 98 (Underground Coal Mines) as proposed. The EPA received no comments objecting to the proposed revisions to subpart FF; therefore, there are no changes from the proposal to the final rule. The EPA is finalizing two technical corrections to: (1) correct the term ''MCF_i'' in equation FF–3 to subpart FF to revise the term ''$1\text{-}(fH2O)_1$'' to ''$1\text{-}(fH2O)_i$'', and (2) to correct 40 CFR 98.326(t) to add the word ''number'' after the word ''identification'' to clarify the reporting requirement. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal.

S. Subpart GG—Zinc Production

This section discusses the final revisions to subpart GG. We are finalizing amendments to subpart GG of part 98 (Zinc Production) as proposed. The EPA received only supportive comments for the proposed revisions to subpart GG. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart GG. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal.

The EPA is finalizing one revision to add a reporting requirement at 40 CFR 98.336(a)(6) and (b)(6) for the total amount of electric arc furnace (EAF) dust annually consumed by all Waelz kilns at zinc production facilities. The final data elements will only require segregation and reporting of the mass of EAF dust consumed for all kilns. These requirements apply to reporters using either the CEMS direct measurement or mass balance calculation

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[18] See ''Technical Support for Proposed Revisions to Subpart DD (2021),'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

methodologies. Reporters currently collect information on the EAF dust consumed on a monthly basis as part of their existing operations as a portion of the inputs to equation GG–1 to subpart GG; reporters will only be required to sum all EAF dust consumed on a monthly basis for each kiln and then for all kilns at the facility for reporting and entering the information into e-GGRT. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the final revisions to subpart GG, as described in section VI. of this preamble.

T. Subpart HH—Municipal Solid Waste Landfills

We are finalizing several amendments to subpart HH of part 98 (Municipal Solid Waste Landfills) as proposed. In some cases, we are finalizing the proposed amendments with revisions. In other cases, we are not taking final action on the proposed amendments. Section III.T.1. of this preamble discusses the final revisions to subpart HH. The EPA received several comments on proposed subpart HH revisions which are discussed in section III.T.2. of this preamble. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the final revisions to subpart HH, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart HH

This section summarizes the final amendments to subpart HH. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart HH can be found in this section and section III.T.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

The EPA is finalizing several revisions to subpart HH to improve the quality of data collected under the GHGRP. First, the EPA is finalizing revisions to update the factors used in modeling CH_4 generation from waste disposed at landfills in table HH–1 to subpart HH. As explained in the 2022 Data Quality Improvements Proposal, subpart HH uses a model to estimate CH_4 generation that considers the quantity of MSW landfilled, the degradable organic carbon (DOC) content of that MSW, and the first order decay rate (k) of the DOC. Table HH–1 to subpart HH provides DOC and k values that a reporter must use to calculate their CH_4 generation based on the different categories of waste disposed at that landfill and the climate in which the landfill is located. The EPA previously conducted a multivariate analysis of data reported under subpart HH to estimate updated DOC and k values for each waste characterization option. Details of this analysis are available in the memorandum from Meaghan McGrath, Kate Bronstein, and Jeff Coburn, RTI International, to Rachel Schmeltz, EPA, ''Multivariate analysis of data reported to the EPA's Greenhouse Gas Reporting Program (GHGRP), Subpart HH (Municipal Solid Waste Landfills) to optimize DOC and k values,'' (June 11, 2019), available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424. The EPA is finalizing the following changes as proposed:

- For the Bulk Waste option, amending the bulk waste DOC value in table HH–1 from 0.20 to 0.17.
- For the Modified Bulk Waste option, for bulk MSW waste without inerts and (C&D) waste, amending the DOC value from 0.31 to 0.27.
- For the Waste Composition option, adding a DOC for uncharacterized MSW of 0.32, and revising 40 CFR 98.343(a)(2) to reference using this uncharacterized MSW DOC value rather than the bulk MSW value for waste materials that could not be specifically assigned to the streams listed in table HH–1 for the Waste Composition option.

The EPA is also revising the default decay rate values in table HH–1 for the Bulk Waste option and the Modified Bulk MSW option and adding k value ranges for uncharacterized MSW for the Waste Composition Option. The final k values, which have been revised from those proposed, are shown in table 4 of this preamble. The revised defaults represent the average optimal k values derived through an additional optimization analysis conducted in response to comments where the bulk waste DOC value was set to the revised value of 0.17 and optimal k values were determined for each precipitation category.

TABLE 4—REVISED DEFAULT k VALUES

Factor	Subpart HH default	Units
k values for Bulk Waste option and Modified Bulk MSW option		
k (precipitation plus recirculated leachate <20 inches/year)	0.033	yr − 1.
k (precipitation plus recirculated leachate 20–40 inches/year)	0.067	yr − 1.
k (precipitation plus recirculated leachate >40 inches/year)	0.098	yr − 1.
k value range for Waste Composition option		
k (uncharacterized MSW)	0.033 to 0.098	yr − 1.

The revisions to the DOC and k values in table HH–1 reflect the compositional changes in materials that are disposed at landfills. These updated factors will allow MSW landfills to more accurately model their CH_4 generation. We are also clarifying in the final rule that starting in RY2025 these new DOC and k values are to be applied for disposal years 2010 and later, consistent with when the compositional changes occurred. Additional information on these revisions and their supporting basis may be found in section III.Q. of the preamble to the 2022 Data Quality Improvements Proposal and in the memorandum ''Revised Analysis and Calculation of Optimal k Values for Subpart HH MSW Landfills Using a 0.17 DOC Default and Timing Considerations'' included in Docket ID. No. EPA–HQ–OAR–2019–0424.

We are also finalizing, as proposed, revisions to account for CH_4 emission events that are not well quantified under the GHGRP including: (1) a poorly operating or non-operating gas collection system; and (2) a poorly operating or non-operating destruction device. The EPA is finalizing, as proposed, revisions and additions to address these scenarios as follows:

- Revising equations HH–7 and HH–8 to more clearly indicate that the ''f_{Rec}'' term is dependent on the gas collection system, to clarify how the equation applies to landfills that may have more than one gas collection system and may have multiple measurement locations associated with a single gas collection system.

- Clarifying in ''f_{Rec}'' that the recovery system operating hours only include those hours when the system is operating normally. Facilities should not include hours when the system is shut down or when the system is poorly operating (*i.e.,* not operating as intended). Poorly operating systems can be identified when pressure, temperature, or other parameters indicative of system performance are outside of normal variances for a significant portion of the system's gas collection wells.
- For equations HH–6, HH–7, and HH–8, revising the term ''f_{Dest}'' to clarify that the destruction device operating hours exclude periods when the destruction device is poorly operating. Facilities should only include those periods when flow was sent to the destruction device and the destruction device was operating at its intended temperature or other parameter that is indicative of effective operation. For flares, periods when there is no flame present must be excluded from the annual operating hours.

Following consideration of comments received, the EPA is finalizing two minor clarifications of the term ''$f_{Dest,n}$'' in equations HH–7 and HH–8. First, we are removing the redundant phrase ''as measured at the nth measurement location.'' Second, we are removing the word ''pilot'' to clarify that for flares used as a destruction device, the annual operating hours must exclude any period in which no flame is present, either pilot or main. These changes account for variances in flare operation, *e.g.,* flares which may only use a pilot on startup. See section III.T.2. of this preamble for additional information on related comments and the EPA's response.

In the 2023 Supplemental Proposal, we proposed that facilities that conduct surface-emissions monitoring must use that data and correct the emissions calculated in equations HH–6, HH–7, and HH–8 to account for excess emissions when the measured surface methane concentration exceeded 500 ppm based on a correction term added to those equations. We also proposed for facilities not conducting surface-emissions monitoring to use collection efficiencies that are 10-percentage points lower than the historic collection efficiencies in table HH–3 to subpart HH. Following consideration of comments received, we are not taking final action on the surface-emissions monitoring correction term that was proposed. Instead, we are finalizing the proposed lower collection efficiencies in table HH–3 to subpart HH, but applying the reduced collection efficiencies for all reporters under subpart HH. See section III.T.2. of this preamble for additional information on related comments and the EPA's response.

The EPA is also finalizing several revisions to the reporting requirements for subpart HH, including more clearly identifying reporting elements associated with each gas collection system, each measurement location within a gas collection system, and each control device associated with a measurement location. First, we are finalizing revisions to landfills with gas collection systems consistent with the proposed revisions in the methodology, *i.e.,* to separately require reporting for each gas collection systems and for each measurement location within a gas collection system. We are requiring, for each measurement location that measures gas to an on-site destruction device, certain information be reported about the destruction device, including: type of destruction device; the total annual hours where gas was sent to the destruction device; a parameter indicative of effective operation, such as the annual operating hours where active gas flow was sent to the destruction device and the destruction device was operating at its intended temperature; and the fraction of the recovered methane reported for the measurement location directed to the destruction device. We are also requiring reporting of identifying information for each gas collection system, each measurement location within a gas collection system, and each destruction device. We are also finalizing reporting requirements for landfills with gas collection systems to indicate the applicability of the NSPS (40 CFR part 60, subparts WWW or XXX), state plans implementing the EG (40 CFR part 60, subparts Cc or Cf), and Federal plans (40 CFR part 62, subparts GGG and OOO).

In the 2023 Supplemental Proposal, the EPA also sought comment on how other CH_4 monitoring technologies, *e.g.,* satellite imaging, aerial measurement, vehicle-mounted mobile measurement, or continuous sensor networks, might enhance subpart HH emissions estimates. The EPA did not propose, and therefore is not taking final action on, any amendments to subpart HH to this effect. However, the EPA did seek comment on the availability of existing monitoring technologies, and regulatory approaches and provisions necessary to incorporate such data into subpart HH for estimating annual emissions. We will continue to review the comments received along with other studies and may amend subpart HH to allow the incorporation of additional measurement or monitoring methodologies in the future.

2. Summary of Comments and Responses on Subpart HH

This section summarizes the major comments and responses related to the proposed amendments to subpart HH. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart HH.

Comment: Numerous commentors stated that methane detection technology, specifically top-down direct measurement from aerial studies, has greatly improved the ability to observe and quantify emissions from landfills (*e.g.,* Krautwurst, et al., 2017; Cusworth, et al., 2022).[19] [20] Some commenters noted that, among several studies in California, Maryland, Texas, and Indiana, there are discrepancies between observed data collected from these new detection technologies and the estimated emissions from the models that the EPA currently uses. Several commenters pointed to a recent study (Nesser, et al., 2023) using satellite data that highlighted that at 33 of 70 landfills studied, U.S. GHG Inventory landfill emissions are underestimated by 50 percent when compared to the current top-down approaches.[21] These discrepancies indicate methane emissions from landfills may be considerably higher than currently recorded. Some commenters stated that advanced methane monitoring technology has improved significantly in effectiveness and cost, and provided specific input regarding advanced methane monitoring technologies available for landfills and how their data might enhance subpart

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[19] Krautwurst, S., et al., (2017). ''Methane emissions from a Californian landfill, determined from airborne remote sensing and in situ measurements.'' Atmos. Meas. Tech. 10:3429–3452. *https://doi.org/10.5194/amt-10-3429-2017.*

[20] Cusworth, D., et al., (2020). ''Using remote sensing to detect, validate, and quantify methane emissions from California solid waste operations.'' Environ. Res. Lett. 15: 054012.

[21] Nesser, H., et al. 2023. High-resolution U.S. methane emissions inferred from an inversion of 2019 TROPOMI satellite data: contributions from individual states, urban areas, and landfills, *EGUsphere* [preprint], *https://doi.org/10.5194/egusphere-2023-946,* 2023.

HH emissions reporting. The commenters pointed to both screening and close-range technologies that would be beneficial for pinpointing leaks or emission sources, and outlined several technologies including satellite imaging, aerial measurements, vehicle-mounted mobile measurement, and continuous sensor networks. The commenters recommended comprehensive monitoring with both screening and close-range technologies to provide full coverage. The commenters suggested the use of these technologies to catch large emission events that are not accounted for in the existing reporting requirements. Commenters noted that the EPA could review submitted reports and activity data to determine how to best quantify the observed large release events as compared to annual reported emissions (*e.g.,* updating f_{Rec} or f_{Dest} values to account for periods of downtime or poor performance not captured that contributed to a large discrepancy).

Other commenters recommended that the EPA create a mechanism under subpart HH for receiving and considering third-party observational data that the EPA could then use to revise reported emissions as necessary. Some commenters suggested the EPA base a threshold for these sources of 100 kg/hour. Commenters also recommended setting assumptions for the duration of the emissions similar to those proposed for subpart W of part 98 (Petroleum and Natural Gas Systems). Some commenters suggested the EPA should embrace for landfills the same tiered methane emissions monitoring approach as is utilized in its proposed rulemaking for the oil and gas sector. Commenters also suggested a tiered approach that combines continuous monitoring ground systems with periodic remote sensing along with approaches for translating methane concentrations from top-down sources to source-specific emission rates. Commenters urged that the sooner the EPA can move toward top-down or facility-wide measurement of emissions for reporting or validation of reported values, the sooner reported and measured emissions would be reconcilable and verifiable. A few commenters also recommended that the EPA facilitate the flow of information from other agencies (the National Aeronautics and Space Administration (NASA), National Oceanic and Atmospheric Administration (NOAA), National Institute of Standards and Technology (NIST), and U.S. Department of Energy (DOE)), third parties, and operators to find and mitigate plumes faster.

Several commenters provided recommendations for additional reporting requirements such as gas collection and capture system (GCCS) type and design, destruction device type and characteristics, monitoring technologies, site cover type, construction periods, and compliance issues which may relate to closures of control devices.

Response: The EPA agrees that recent aerial studies indicate methane emissions from landfills may be considerably higher than bottom-up emissions reported under subpart HH for some landfills. Emissions may be considerably higher due to emissions from poorly operating gas collection systems or destruction devices and leaking cover systems. The supplemental proposal included revisions to the monitoring and calculation methodologies in subpart HH to account for these scenarios. In particular, proposed equations HH–6, HH–7, and HH–8 included modifications to incorporate direct measurement data collected from methane surface-emissions monitoring. In the supplemental proposal, we also requested information about other direct measurement technologies and how their data may enhance emissions reporting under subpart HH. We received many responses to our request. Based on the comments received, we are not taking final action at this time regarding the incorporation of other direct measurement technologies for the following reasons. First, most top-down, facility measurements are taken over limited durations (a few minutes to a few hours) typically during the daylight hours and limited to times when specific meteorological conditions exist (*e.g.,* no cloud cover for satellites; specific atmospheric stability and wind speed ranges for aerial measurements). These direct measurement data taken at a single moment in time may not be representative of the annual CH_4 emissions from the facility, given that many emissions are episodic. If emissions are found during a limited duration sampling, that does not necessarily mean they are present for the entire year. And if emissions are not found during a limited duration sampling, that does not mean significant emissions are not occurring at other times. Extrapolating from limited measurements to an entire year therefore creates risk of either over or under counting actual emissions. Second, while top-down measurement methods, including satellite and aerial methods, have proven their ability to identify and measure large emissions events, their detection limits may be too high to detect emissions from sources with relatively low emission rates or that are spread across large areas, which is common for landfills.[22] This is likely why only seven percent of the landfills in the Duren, et al. (2019) study had detectable emissions. The EPA will continue to review additional information on existing and advanced methodologies and new literature studies, and consider ways to effectively incorporate these methods and data in future revisions under subpart HH for estimating annual emissions.

For the oil and gas sector, the super-emitter program that allows third-party measurement data to be submitted was proposed under 40 CFR part 60, subpart OOOOb (87 FR 74702, December 6, 2022). The GHGRP looked to use this information, but we did not develop or propose such a program under the GHGRP. As such, this type of program is beyond the scope of the proposed rule. We will consider whether developing and implementing a similar super-emitter program within subpart HH of part 98 or the overall GHGRP is appropriate under future rulemakings.

We proposed, and are finalizing, several additional reporting elements including, for landfills with a gas collection system, information on the applicability of the NSPS (40 CFR part 60, subparts WWW or XXX), state plans implementing the EG (40 CFR part 60, subparts Cc or Cf), and Federal plans (40 CFR part 62, subparts GGG and OOO). We note that several of the items suggested are already reporting elements. For example, we already require reporting of a description of the gas collection system, such as the manufacturer, capacity, and number of wells, which provides requested information on GCCS type and design. We also proposed and are finalizing reporting requirements for the type of destruction device. We already require reporting of cover type. We consider the reporting requirements to be sufficient based on the current methodologies used to estimate CH_4 emissions. We will consider the need for additional reporting elements if we incorporate additional measurement or monitoring methodologies in future rulemakings.

Comment: Several commentors expressed limited support for the proposed use of surface emission monitoring data to help account for

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[22] Duren, et al. 2019. ''California's methane super-emitters.'' *Nature,* Vol. 575, Issue 7781, pp. 180–184, available at *https://doi.org/10.1038/s41586-019-1720-3.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

emissions from cover leaks. These commenters either recommended that the EPA use more quantitative emission measurement methods instead of surface-emissions monitoring or to require that the surface-emissions monitoring be conducted at 25-foot intervals consistent with California and other state requirements, and to use a lower leaks definition of 25 parts per million volume (ppmv), rather than using the proposed 30-meter intervals (about 98-foot intervals) with leaks defined as concentrations of 500 ppmv or more above background, to help ensure the surface-emissions monitoring identifies all leaks from the landfill's surface. Other commenters opposed the proposed use of a surface-emissions monitoring correction term in equations HH–6, HH–7, and HH–8. One commenter noted that the correction term that the EPA proposed relied on one study conducted over 20 years ago at one landfill in Canada. This commenter cited several other studies [23][24][25][26] that showed significant variability in correlations between surface methane concentrations and methane emissions and indicated that the EPA should not rely on the results of this limited single study. Another commenter suggested that there is nothing special from a technical perspective of 500 ppmv surface concentration that should drive a step function change in correcting for emissions and surface oxidation, as proposed by the EPA. This commenter indicated that there is already uncertainty in the gas collection efficiencies and that including the proposed surface methane concentration term simply adds to the uncertainty. The commenter recommended mandating the use of lower collection efficiencies when there is evidence of a high number of exceedances or a high surface methane concentration, rather than adding the surface methane concentration term to equations HH–6, HH–7, and HH–8. This commenter also cited the work of Dr. Tarek Abichou (Kormi, et al., 2017 and 2018) for using surface concentration measurements to estimate emissions.[27][28]

Response: After considering comments received and reviewing additional studies, including those cited by the commenters, we are not taking final action on the proposed surface-emissions monitoring correction term at this time.[29] Upon review of the literature studies cited by one commenter (Abichou, et al., 2011; Abidini, 2014; Lando, et al., 2017; Hettiarachchi, et al., 2023), we confirmed that there is significant variability in measured surface concentrations and methane emissions flux across different landfills. The proposed correction factor, attributed to Heroux, et al. (2010),[30] was the smallest of the correlation factors found across the other cited literature studies we reviewed. Based on a preliminary review of the additional study data, a more central tendency estimate of the correction factor term would be four to six times higher than the correction term proposed.

Due to the high uncertainty in the proposed correction factor, we are assessing whether the correction term proposed for equations HH–6, HH–7, and HH–8 is the most appropriate method for developing a site-specific correction for the overall gas collection efficiency for reporters under subpart HH. The approach presented by Kormi, et al. (2017, 2018) uses a Gaussian plume model in conjunction with surface methane concentration measurements to estimate emissions. This approach appears too complex to incorporate into subpart HH. We are also evaluating other direct measurement technologies for assessing more accurate, landfill-specific gas collection efficiencies. Therefore, we decided not to take final action on the proposed correction term for equations HH–6, HH–7, and HH–8 at this time while we consider and evaluate other options. The EPA will continue to review additional information on existing and advanced methodologies and new literature studies and consider ways to effectively incorporate these methods and data in future revisions under subpart HH for estimating annual emissions.

Comment: Numerous commenters cited studies suggesting that subpart HH underestimates the actual methane emissions released from landfills.[31][32] These commenters noted that the underestimation in subpart HH emissions is primarily due to high default gas collection efficiencies in subpart HH. Two commenters asserted that gas collection efficiencies over 90 percent should not be used. One of these commenters noted that despite its own two-year study indicating otherwise, the EPA uses a 95 percent collection efficiency for landfills with final covers.[33] Two commenters opposed the EPA's use of the Maryland landfill data to support the proposed 10-percentage point decrease in landfill gas collection efficiencies, noting that these gas collection efficiencies were calculated based on modeled methane generation rather than actual methane emissions measurements. One commenter further suggested that the Maryland study was not properly peer-reviewed and is not suitable for use by the EPA in rulemaking according to the EPA's Summary of General Assessment Factors For Evaluating the Quality of Scientific and Technical Information (hereinafter referred to as ''General Assessment Factors'').[34] The commenter further stated that the Maryland study is based on a small subset of landfills that is likely not representative of the sector and the EPA's reliance on that study to support a change to the default collection efficiency table (table HH–3

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[23] Abichou, T., J. Clark, and J. Chanton. 2011. ''Reporting central tendencies of chamber measured surface emission and oxidation.'' *Waste Management,* 31: 1002–1008. *https://doi.org/10.1016/j.wasman.2010.09.014.*

[24] Abedini, A.R. 2014. Integrated Approach for Accurate Quantification of Methane Generation at Municipal Solid Waste Landfills. Ph.D. thesis, Dept. of Civil Engineering, University of British Columbia.

[25] Lando, A.T., H. Nakayama, and T. Shimaoka. 2017. ''Application of portable gas detector in point and scanning method to estimate spatial distribution of methane emission in landfill.'' *Waste Management,* 59: 255–266. *https://doi.org/10.1016/j.wasman.2016.10.033.*

[26] Hettiarachchi, H., E. Irandoost, J.P. Hettiaratchi, and D. Pokhrel. 2023. ''A field-verified model to estimate landfill methane flux using surface methane concentration measurements.'' *J. Hazard. Toxic Radioact. Waste,* 27(4): 04023019. *https://doi.org/10.1061/JHTRBP.HZENG-1226.*

[27] Kormi, T., N.B.H. Ali, T. Abichou, and R. Green. 2017. ''Estimation of landfill methane emissions using stochastic search methods.'' *Atmospheric Pollution Research,* 8(4): 597–605. *https://dx.doi.org/10.1016/j.apr.2016.12.020.*

[28] Kormi, T., et al. 2018. ''Estimation of fugitive landfill methane emissions using surface emission monitoring and Genetic Algorithms optimization.'' *Waste Management* 2018, 72: 313–328. *https://dx.doi.org/10.1016/j.wasman.2016.11.024.*

[29] Irandoost, E. (2020). An Investigation on Methane Flux in Landfills and Correlation with Surface Methane Concentration (Master's thesis, University of Calgary, Calgary, Canada). Retrieved from *https://prism.ucalgary.ca. http://hdl.handle.net/1880/111978.*

[30] Héroux, M., C. Guy and D. Millette. 2010. ''A statistical model for landfill surface emissions.'' *J. of the Air & Waste Management Assoc.* 60:2, 219–228. *https://doi.org/10.3155/1047-3289.60.2.219.*

[31] Oonk, H., 2012. ''Efficiency of landfill gas collection for methane emissions reduction.'' *Greenhouse Gas Measurement and Management,* 2:2–3, 129–145. *https://doi.org/10.1080/20430779.2012.730798.*

[32] Nesser, H., et al., 2023. ''High-resolution U.S. methane emissions inferred from an inversion of 2019 TROPOMI satellite data: contributions from individual states, urban areas, and landfills.'' *EGUsphere* [preprint], *https://doi.org/10.5194/egusphere-2023-946.*

[33] ARCADIS, 2012. Quantifying Methane Abatement Efficiency at Three Municipal Solid Waste Landfills; Final Report. Prepared for U.S. EPA, Office of Research and Development, Research Triangle Park, NC. EPA Report No. EPA/600/R–12/003. January. *https://nepis.epa.gov/Exe/ZyPDF.cgi/P100DGTB.PDF?Dockey=P100DGTB.PDF.*

[34] Available at *https://www.epa.gov/sites/default/files/2015-01/documents/assess2.pdf.* Accessed January 9, 2024.

to subpart HH) is inappropriate and will lead to inaccurate reporting of GHG emissions from the sector. This commenter stated that the EPA should continue to rely on the gas collection efficiencies recommended in the Solid Waste Industry for Climate Solutions (''SWICS'') white paper entitled *Current MSW Industry Position and State-of-the-Practice on LFG Collection Efficiency, Methane Oxidation, and Carbon Sequestration in Landfills.*[35] According to the commenter, the SWICS white paper is more comprehensive and relevant than the Maryland study. The commenters noted that the SWICS white paper is being revised and encouraged the EPA to delay revisions to the gas collection efficiency until the revised SWICS white paper is released.

Response: We reviewed the various studies cited by commenters, including available versions of the SWICS white paper. Upon review of these papers and comments received, we maintain our position that the historical collection efficiencies are overstated and that it is appropriate to apply the lower collection efficiency to all landfills. In our review of the SWICS white paper, which was the basis for the historical gas collection efficiencies, we noted that data were omitted due to poor operation of gas collection system. Thus, we consider the historical gas collection efficiencies to be representative of ideal gas collection efficiencies. In our proposal, we required facilities that conduct surface-emission monitoring data to apply a correction factor that would reduce the overall collection efficiency, clearly indicating that we thought the current collection efficiencies are overstated, even for regulated landfills. While we expected that the surface emission correction factor would result in lower emissions than those calculated using the 10-percentage point decrease in collection efficiency, based on our review of other studies correlating surface methane concentrations with methane flux, a more central tendency correlation factor is projected to yield emissions similar to a 10-percentage point decrease in collection efficiency. All the measurement study data we reviewed suggests that current GHGRP collection efficiencies are overstated on average by 10-percentage points or more (Duan, et al., 2022 and Nesser, et al., 2023).[36] In reviewing the data from Nesser, et al. (2023), including the supplemental information,[37] we found that all 38 landfills for which gas collection systems were reported were subject to the NSPS or EG. Comparing the gas collection efficiencies directly reported in the GHGRP, 35 of the 38 landfills had lower or similar measured gas collection efficiencies to those reported in subpart HH. With a 10-percentage point decrease in the default gas collection efficiencies, measured gas collection efficiencies were still at least 10-percentage points lower for 20 of the 38 landfills, approximately equivalent for 13 landfills, and only higher than subpart HH proposed lower default collection efficiencies for 5 of the landfills. Similar low average collection efficiencies were noted by Duan, et al., (2022). Therefore, based on direct measurement data for landfills, we determined it is appropriate to finalize the lower default gas collection efficiencies and apply the lower gas collection efficiency for all landfills.

While the Maryland study data suggests that the gas collection efficiency for voluntary systems may be lower than for regulated gas collection systems, we agree with commenters that these gas collection efficiencies are based on modeled generation rather than measured emissions. The DOC values for individual landfills can vary significantly and the differences observed could be due to differences in the wastes managed at the different Maryland landfills. We could not identify direct measurement study data by which to support further reductions in gas collection efficiencies for voluntary gas collection systems. Therefore, we are providing a single set of gas collection efficiencies for subpart HH reporters to use.

In conclusion, we are finalizing gas collection efficiencies that are lower than those historically provided in subpart HH by 10-percentage points based on comments received and review of recent landfill methane emission measurement studies for landfills with gas collection systems. We had proposed these collection efficiencies for facilities not conducting surface emission monitoring, but we are now finalizing these lower gas collection efficiencies for all landfills.

Comment: Several commenters provided input on the proposed revisions to equations HH–6 through HH–8 to subpart HH to capture emissions from other large release events. Two commenters suggested that the EPA should require monitoring of both the pilot light and flow rate and that the ''f_{Dest}'' term should be excluded during any period the combustion device is not operating properly. The commenters specified that ''f_{Dest}'' should be excluded during any period when the reporter has operational data indicating that the combustion device is not operating according to manufacturer specifications or when the reporter has received credible monitoring data showing an unlit or malfunctioning control device.

One commenter stated that the proposed revisions would be difficult to implement and tend to capture very limited or marginal data. The commenter asserted that gas collection systems by nature require constant adjustment of temperature, pressure, and other parameters or may be subject to frequent repairs that would not be expected to affect the overall control efficiency. The commenter asked the EPA to remove ''normally'' from the first sentence of the proposed definition of ''f_{Rec}'' and remove ''or poor operation, such as times when pressure, temperature, or other parameters indicative of operation are outside of normal variances,'' from the second sentence.

The commenter also expressed concerns regarding how the proposed revisions to ''f_{Dest}'' applies to flares, stating that a large portion of landfill controls use open flares, or are equipped with automatic shutoffs, which have no parameters for monitoring effective operation other than the presence of a flame. The commenter requested the sentence addressing the pilot flame (''For flares, times when there is no pilot flame present must be excluded from the annual operating hours for the destruction device.'') be removed from the proposed revision of ''f_{Dest},'' because it is confusing, unnecessary, and technically incorrect, as a pilot is typically only required during startup.

One commenter also requested the EPA remove the phrase ''. . . as measured at the nth measurement location'' from the first sentence of ''f_{Dest}'' description; the commenter stated the text adds confusion by implying that the time gas is sent to the nth measurement location is equal to the time gas is sent to the control device, which may be incorrect for measurement locations with more than one control device. The commenter also

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[35] SCS Engineers. 2009. Current MSW Industry Position and State-of-the-Practice on LFG Collection Efficiency, Methane Oxidation, and Carbon Sequestration in Landfills. Prepared for Solid Waste Industry for Climate Solutions (SWICS). Version 2.2. *https://www.scsengineers.com/wp-content/uploads/2015/03/Sullivan_SWICS_White_Paper_Version_2.2_Final.pdf.*

[36] Duan, Z., Kjeldsen, P., & Scheutz, C. (2022). Efficiency of gas collection systems at Danish landfills and implications for regulations. Waste management (New York, N.Y.), 139, 269–278. *https://doi.org/10.1016/j.wasman.2021.12.023.*

[37] See *https://egusphere.copernicus.org/preprints/2023/egusphere-2023-946/egusphere-2023-946-supplement.pdf.*

proposed a definition striking out ''The annual operating hours for the destruction device should include only those periods when flow was sent to the destruction device and the destruction device was operating at its intended temperature or other parameter indicative of effective operation.'' The commenter added that because flares and other destruction devices are designed with fail-closed valves or other devices to prevent venting of gas when they are not operating, applying the definition as written overestimates emissions when a measurement location has more than one destruction device and all devices are not operating at the same time.

Response: The EPA agrees with the commenters regarding monitoring the flow rate of the landfill gas; however, a change to the proposed rule is not necessary in this case as the continuous monitoring of the gas flow is already required in 40 CFR 98.343. The EPA disagrees with the comment that ''EPA should likewise specify that f_{Dest} must be excluded during any period when the pilot light and flow rate are not meeting manufacturer specifications for complete combustion.'' Adding this specification to the rule is not necessary as the revision to the definition of f_{Dest} already accounts for this scenario. The proposed revision to the f_{Dest} definition in the supplemental proposal states, ''The annual operating hours for the destruction device should include only those periods when flow was sent to the destruction device and the destruction device was operating at its intended temperature or other parameter indicative of effective operation.'' Thus, if the destruction device has manufacturer specifications for effective operation that are not met during its operation, the revision to the f_{Dest} definition requires those periods to be excluded in the hours for f_{Dest}. We will further evaluate how credible monitoring data may be defined and excluded from f_{Dest} in a future rulemaking.

The EPA disagrees with the proposed edits to the definition of f_{Rec}, which are to remove the word ''normally'' from the first sentence and remove the phrase ''or poor operation, such as times when pressure, temperature, or other parameters indicative of operation are outside of normal variances'' from the second sentence. These edits would allow for all operating hours in the calculation regardless of how the system operated. We asked for comment on what set of parameters should be used to identify poorly operating periods and whether a threshold on the proportion of wells operating outside of their normal operating variance should be included in the definition of f_{Rec} to define periods of poor performance.

With regards to the commenters' input on the definition of f_{Dest}, the EPA agrees with removing ''as measured at the nth measurement location'' from the first sentence of the definition as the commenter notes, ''flares and other destruction devices are designed with fail-closed valves or other devices to prevent venting of gas when they are not operating, keeping that phrase can overestimate emissions when a measurement location has more than one destruction device and all devices are not operating at the same time.'' We are revising this sentence to remove ''as measured at the nth measurement location.'' We disagree with removing from the definition ''For flares, times when there is no pilot flame present must be excluded from the annual operating hours for the destruction device.'' Instead, we are revising this sentence to read ''For flares, times when there is no flame present must be excluded from the annual operating hours for the destruction device.'' We believe the lack of a flame is an indication the flare is not operating effectively. Lastly, we disagree with removing the sentence, ''The annual operating hours for the destruction device should include only those periods when flow was sent to the destruction device and the destruction device was operating at its intended temperature or other parameter indicative of effective operation.'' We believe this sentence is necessary to ensure the calculation of f_{Dest} represents proper operation of the destruction device.

Comment: We received several comments regarding the revised DOC values. Some commenters supported lowering of the default DOC for bulk waste from 0.20 to 0.17, citing similar findings in a 2019 Environmental Research and Education Foundation (EREF) study.[38] These commenters generally opposed the proposed default value of 0.27 for bulk MSW (excluding inerts and construction and demolition (C&D) waste) and the proposed default value of 0.32 for uncharacterized wastes and recommended the use of either the value of 0.19 from the EREF report or the 0.17 value for bulk wastes for these other general waste categories. According to these commenters, the EPA's method for determining the DOC for bulk MSW (excluding inerts and C&D waste) does not comport with how landfills characterize and manage input waste streams, and the high default DOC value for bulk MSW makes the modified bulk MSW option unusable. Other commenters opposed the proposed reduction in bulk waste and bulk MSW default DOC values, indicating that this will lead to lower emissions over the life of the landfill when research indicates emissions inventories of landfill emissions underestimate actual emissions. One commenter referenced a paper (Bahor, et al., 2010) that, according to the commenter, validated the default DOC of MSW to be 0.20.[39] Other commenters noted that many landfill reporters were taking advantage of the composition method by only reporting inerts and uncharacterized wastes. These commenters supported the proposed default value of 0.32 for uncharacterized wastes.

Response: The EPA included a DOC of 0.20 for bulk waste in subpart HH because the data we reviewed circa 2000 to 2010 indicated that was the best fit DOC value.[40] As noted in the memorandum ''Modified Bulk MSW Option Update'' included in Docket ID. No. EPA–HQ–OAR–2019–0424, we have seen a significant decrease in the percentage of paper and paperboard products being landfilled due to increased recycling of these waste streams. This change in the composition of MSW landfilled supports and confirms the drop in DOC from 0.20 to 0.17 over the time period between 2005 and 2011. With respect to the Bahor, et al. (2010) study, it appears that the HHV measurement data was made using data from 1996 to 2006, with biogenic correction factors developed over 2007 and 2008. Based on the timing of the measurements made, agreement with the DOC value of 0.20 is not surprising and consistent with the findings by which we originally used a default DOC value of 0.20. We specifically sought to reassess the average DOC values considering more recent data to account for potential changes in DOC values over the past decade. Based on our analysis, an average DOC value of 0.17 provides a better fit with current landfill practices. Therefore, we are finalizing a revision of the default DOC value to

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[38] The Environmental Research & Education Foundation (2019). ''Analysis of Waste Streams Entering MSW Landfills: Estimating DOC Values & the Impact of Non-MSW Materials.'' Available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

[39] Bahor, Brian, et al. 2010. ''Life-cycle assessment of waste management greenhouse gas emissions using municipal waste combustor data.'' *Journal of Environmental Engineering* 136.8 (2010): 749–755. *https://doi.org/10.1061/(ASCE)EE.1943-7870.0000189.*

[40] RTI International (2004). Solid Waste Inventory Support—Review Draft: Documentation of Methane Emission Estimates. Prepared for U.S. EPA, Office of Atmospheric Programs, Washington, DC. September 29.

0.17 as proposed. However, we note that the proposed revision was not clear regarding how the new DOC value should be incorporated into the facility's emissions estimate. Some reporters may only begin applying the new DOC value to new wastes being disposed of in 2025 and later years. Other reporters may opt to revise the DOC value for all wastes disposed of in the landfill for all previous disposal years. This could lead to significant discrepancies between emissions reported by reporters with similar landfills and also between the emissions reported for different years by a given reporter. As noted in this discussion, we expect that wastes disposed of prior to 2010 are best characterized using a default DOC value of 0.20 and that wastes disposed of in 2010 and later years are best characterized using a default DOC of 0.17. Therefore, while we are finalizing a revision in the default bulk waste DOC value to 0.17, we are also finalizing clarifications to these revisions to incorporate these revisions consistently across reporters and consistent with the timeframe where the reduction in DOC occurred. Specifically, we are maintaining the historic DOC value of 0.20 for historic disposal years (prior to 2010) and, starting with RY2025, requiring the use of the revised DOC value of 0.17 for disposal years 2010 and later (see memorandum ''Revised Analysis and Calculation of Optimal k values for Subpart HH MSW Landfills Using a 0.17 DOC Default and Timing Considerations'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424).

With respect to the proposed DOC value for bulk MSW (excluding inerts and C&D waste), the approach we used to develop the proposed DOC value is consistent with the approach we used when we originally developed and provided the modified bulk waste option following consideration of comments received (75 FR 66450, October 28, 2010). This option was specifically provided to address comments that the waste composition option was too detailed for most landfill operators to use and that landfill operators should have the opportunity to characterize some of the waste received as inerts under the bulk waste option. Because the DOC values for bulk waste option were derived based on the full quantity of waste disposed at landfills, that DOC value for bulk waste intrinsically includes inerts. Therefore, we sought to develop a representative MSW DOC value that excludes inerts for use in the modified bulk MSW option. We disagree that this makes the modified bulk waste option inaccurate or unusable. On the contrary, we find that using the bulk waste DOC value in the modified bulk MSW option would be less accurate for predicting the CH_4 generation for the modified bulk MSW option because the DOC value for bulk waste was determined by the full quantity of waste disposed at landfills including inerts and C&D waste. We also agree with commenters that some reporters are misusing the waste composition option in order to separately account for inerts but then use the bulk waste DOC value for the rest of the MSW. We conducted a multivariant analysis to project the DOC of uncharacterized MSW in landfills for which reporters used the waste composition method and the DOC for this uncharacterized waste was estimated to be 0.32. This agrees well with the proposed DOC value for bulk MSW of 0.27 and confirms that, when facilities separately report inert waste quantities, the DOC for the remaining MSW (excluding inerts and C&D waste) is much higher than suggested by some of the commenters. Consequently, we concluded that our proposed values of 0.27 for bulk MSW (excluding inerts and C&D waste) and 0.32 for uncharacterized waste should be finalized as proposed. Similar to our clarification regarding how the revision in bulk waste DOC must be implemented, we are finalizing requirements to use the current bulk MSW (excluding inerts and C&D waste) DOC value of 0.31 for historic disposal years (prior to 2010) and requiring the use of the revised bulk MSW (excluding inerts and C&D waste) DOC value of 0.27 for disposal years 2010 and later, consistent with the timeline for which these values were determined. Because we have no method to indicate a change in DOC for uncharacterized wastes, we are requiring the use of the new DOC for uncharacterized waste using the composition option of 0.32 for all years for which the composition option was used.

We also disagree with commenters that having a high bulk MSW default DOC value makes the modified bulk MSW method unusable. Based on waste characterization data as reported for RY2022, approximately 23 percent use the modified bulk MSW method, which suggests a quarter of the reports find the modified bulk MSW option useful. While this option was specifically provided for landfills that accept large quantities of C&D waste or inert waste streams, we disagree that its use should be restricted to that scenario. There is significant variability in the DOC of bulk waste from landfill to landfill. There are many cases when the quantity of landfill gas recovered exceeds the modeled methane generation rates. This is a clear indication that the default DOC (and/or k value) is too low. For reporters with high actual CH_4 generation rates, as noted by the quantity of CH_4 recovered at the landfill, we find that the use of the modified bulk MSW option is appropriate for these reporters and would likely provide a more accurate estimate of modeled CH_4 generation, even if these reporters do not have large quantities of inert or C&D wastes. We encourage reporters that have CH_4 recovery rates exceeding their modeled CH_4 generation rates to evaluate and use, as appropriate, the modified bulk MSW or waste composition options in order to more accurately estimate modeled methane generation.

Comment: Several comments supported revisions to decay rate constants (k values) that more closely match the IPCC recommendations. Other comments were critical of the revisions, suggesting the proposed k values were too high. One commenter noted that the original k values were developed using a separate analysis considering the use of the CH_4 generation potential (Lo, analogous to the DOC input for the first order decay model used in subpart HH). The commenter noted that optimizing k and DOC values simultaneously can lead to extreme and unrealistic values because an error in one value causes an offsetting error in the other. The commenter also stated that the EPA allowed an extremely wide range for the ''optimized'' k values (*e.g.,* 0.001 to 0.400 for dry climates) and should have constrained the k values to more realistic values. The commenter also suggested that the EPA rely on its own research as published in PLoS ONE (Jain et al., 2021).[41] Finally, the commenter suggested that multivariant analysis was not peer-reviewed and therefore does not appear to comply with the General Assessment Factors.

Response: The EPA reviewed the documentation supporting the existing DOC and k value defaults used for subpart HH (RTI International, 2004). Importantly, the memorandum documents that the development of the DOC and k values utilized a two-step process. The first step was a

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[41] Jain, P., et al. 2021. ''Greenhouse gas reporting data improves understanding of regional climate impact on landfill methane production and collection.'' PLoS ONE, at 1–3, 10–11 (Feb. 26, 2021), available at *https://journals.plos.org/plosone/article?id=10.1371/journal.pone.0246334.*

multivariant analysis, similar to the analysis conducted in 2019 (McGrath et al., 2019), which was used to determine an optimal DOC value. The second step was to determine optimal k values for each precipitation range using the optimal DOC value from the multivariant analysis. At proposal, we used the DOC and k values determined directly from the multivariant analysis. After consideration of the comments received and the approach used historically, we determined that it would be more appropriate to determine optimal k values once the default DOC value is established. We agree with the commenter that using a fixed DOC value (set at the proposed bulk waste DOC value of 0.17), we expect that the optimal k values in a single-variable analysis would have less variability and better predict methane generation across landfills when using the revised DOC default. Therefore, we conducted this second step of the analysis using the original data set for facilities using the bulk waste approach to determine the optimal k values for these landfills, given a default DOC value of 0.17 (the bulk waste DOC value recommended in the McGrath et al. (2019) memo based on the multivariant analysis).

We also reviewed additional literature to assess reasonable ranges for k values. We found that the lowest allowed k value of 0.001 yr^{-1} was unrealistic and much lower than any k value reported in the literature. We identified some studies suggesting a k value of 0.4 yr^{-1} is possible for wet landfills (or landfills using leachate recirculation). After our review of the additional literature, we revised the allowable k value range from 0.001–0.4 yr^{-1} to 0.007–0.3 yr^{-1}. The results of applying this second step of the analysis, consistent with the approach used previously to develop default k values, indicate that the optimal k values for dry, moderate, and wet climates were 0.033, 0.067, and 0.098 yr^{-1}, respectively (see memorandum ‘‘Revised Analysis and Calculation of Optimal k Values for Subpart HH MSW Landfills Using a 0.17 DOC Default and Timing Considerations’’ available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424). These values are lower than those developed from the multivariant analysis, but still significantly higher than the current defaults in subpart HH. These values also align well with IPCC recommended k value ranges for moderately decaying waste and the k values reported by Jain, et al. (2021). Table 5 of this preamble presents a comparison of the old subpart HH and revised k values with the values recommended by the IPCC and Jain, et al. (2021).

TABLE 5—COMPARISON OF FINALIZED DECAY RATE CONSTANTS (k VALUES IN YRS^{-1}) BY PRECIPITATION RANGE

Precipitation zone	Historic subpart HH and inventory default decay value (k)	Revised subpart HH default decay value (k)	IPCC default decay value (k) ranges for moderately decaying waste	Jain, et al. (2021), recommended k value (and 95% confidence range)
Dry (<20 inches/year)	0.02	0.033	0.04–0.05	0.043 (0.033–0.054)
Moderate (20–40 inches/year)	0.038	0.067	0.04–0.1	0.074 (0.061–0.088)
Wet (>40 inches/year)	0.057	0.098	0.07–0.17	0.090 (0.077–0.105)

Similar to the incorporation of the new DOC values, we note that the proposed revision was not clear regarding how the new k values for bulk waste under the ‘‘Bulk waste option’’ and bulk MSW under the ‘‘Modified bulk MSW option’’ should be incorporated into the facility's emissions estimate. While we are finalizing revisions for the default bulk waste k values for dry, moderate, and wet climates as 0.033, 0.067, and 0.098 yr^{-1}, respectively, we are also finalizing clarifications to these revisions to incorporate these revisions consistently across reporters and consistent with the timeframe where the reduction in DOC occurred. Specifically, starting in RY2025, we are maintaining the historic k values of 0.20, 0.038, and 0.057 yr^{-1} for historic disposal years (prior to 2010) and requiring the use of the revised k values of 0.033, 0.067, and 0.098 yr^{-1} for disposal years 2010 and later. We are finalizing requirements under the modified bulk waste MSW option to use the current bulk MSW (excluding inerts and C&D waste) k values of 0.02 to 0.057 yr^{-1} for historic disposal years (prior to 2010) and requiring the use of the revised bulk MSW (excluding inerts and C&D waste) k values of 0.033 to 0.098 yr^{-1} for disposal years 2010 and later, consistent with the timeline for which these values were determined. Because we have no method to indicate a change in k value for uncharacterized wastes, we are requiring the use of the new k values for uncharacterized waste using the composition option of 0.033 to 0.098 for all years for which the composition option was used.

With respect to compliance with the General Assessment Factors, we considered a wide variety of information, including peer-reviewed material, when developing our proposed and final k values. While our technical support documents are not formally peer reviewed at proposal, we consider the proposal/public review process to be an adequate forum for public review of our analysis and conclusions. After considering the public comments received, we revised our analysis to more closely match the original approach used to determine default k values. We also adjusted our allowable range for k values based on public comment and additional literature review. All information we have reviewed indicate that the historic subpart HH k values are too low and that the values we determined in our re-analysis of the data will provide improved methane generation estimates. For these reasons, we are finalizing revised k values for subpart HH of 0.033, 0.067, and 0.098 yr^{-1} for dry, moderate, and wet climates, respectively. These k values apply to bulk waste, bulk MSW, and uncharacterized MSW, as proposed.

U. Subpart OO—Suppliers of Industrial Greenhouse Gases

We are finalizing several amendments to subpart OO of part 98 (Suppliers of Industrial Greenhouse Gases) as proposed. Section III.U.1. of this preamble discusses the final revisions to subpart OO. The EPA received comments on the proposed revisions to subpart OO which are discussed in section III.U.2. of this preamble. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the revisions to subpart OO as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart OO

This section summarizes the final amendments to subpart OO. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart OO can be found in this section and section III.U.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

The EPA is finalizing several revisions to subpart OO of part 98 that will improve the quality of the data collection under the GHGRP. First, we are adding a requirement at 40 CFR 98.417(c)(7) for bulk importers of F–GHGs to include, as part of the information required for each import in the annual report, the customs entry number. The customs entry number is provided as part of the U.S. Customs and Border Protection (CBP) Form 7501: Entry Summary and is assigned for each filed CBP entry for each shipment. The EPA has made one minor clarification from proposal. We initially proposed the requirement as the ''customs entry summary number''; the final rule modifies 40 CFR 98.416(a)(7) to clarify the requirement to the ''customs entry number,'' which is associated with the CBP Form 7501, ''Entry Summary.''

As proposed, we are adding a reporting requirement at 40 CFR 98.416(k) that suppliers of N_2O, saturated PFCs, SF_6, and fluorinated HTFs identify the end uses for which the N_2O, SF_6, saturated PFC, or fluorinated HTF is used and the aggregated annual quantities of N_2O, SF_6, each saturated PFC, or each fluorinated HTF transferred to each end use, if known. As discussed in the proposed rules, this requirement is based on a similar requirement in subpart PP to part 98 (Suppliers of Carbon Dioxide) and is intended to provide additional insight into the identities and magnitudes of the uses of these compounds, which are currently less well understood than those of other industrial GHGs such as HFCs, although the GWP-weighted totals supplied are relatively large.

The EPA is also finalizing a clarification to the reporting requirements for importers and exporters of F–GHGs, F–HTFs, or N_2O, to revise the required reporting of ''commodity code,'' which is required for importers at 40 CFR 98.416(c)(6) and for exporters at 40 CFR 98.416(d)(4), to clarify that reporters should submit the Harmonized Tariff System (HTS) code for each F–GHG, F–HTF, or N_2O shipped. Reporters will enter the full 10-digit HTS code with decimals, to extend to the statistical suffix, as it was entered on related customs forms. See section III.S. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on the EPA's rationale for these changes.

As discussed in section III.A.1.b. of this preamble, we are finalizing related revisions to the definition of ''fluorinated HTF,'' previously included in subpart I of part 98 (Electronics Manufacturing), and to move the definition to subpart A of part 98 (General Provisions), to harmonize with the changes to subpart OO.

Finally, we are finalizing revisions to 40 CFR 98.416(c) and (d) to clarify that certain exceptions to the reporting requirements for importers and exporters are voluntary, consistent with our original intent. To implement this change, we are finalizing revisions to insert ''importers may exclude'' between ''except'' and ''for shipments'' in the first sentence of § 98.416(c) and (d), deleting the ''for.'' We are also finalizing revisions to clarify that imports and exports of transshipments will both have to be either included or excluded for any given importer or exporter, and we are finalizing a similar clarification for heels. These changes ensure that importers and exporters treat the exceptions consistently. See section III.K. of the preamble to the 2023 Supplemental Proposal for additional information on these revisions and their supporting basis.

In the 2023 Supplemental Proposal, the EPA proposed a requirement at 40 CFR 98.416(c) for bulk importers of F–GHGs to provide, for GHGs that are not regulated substances under 40 CFR part 84 (Phasedown of Hydrofluorocarbons), copies of the corresponding U.S. CBP entry forms (*e.g.,* CBP Form 7501) in their annual report. Following consideration of public comments received on a similar proposed revision to subpart QQ of part 98 (Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment and Closed-Cell Foams), including concerns regarding the availability of this information and the potential burden of submitting large volumes of entry forms, the EPA is not taking final action on the proposed revision to subpart OO. See section III.W. of this preamble for additional information.

2. Summary of Comments and Responses on Subpart OO

This section summarizes the major comments and responses related to the proposed amendments to subpart OO. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart OO.

Comment: One commenter requested that we clarify that chemical supply ''end use'' refers to industry category only, such as electronics or semiconductor use, and does not refer to more specific uses. The commenter recommended that specific purchases and purposes of chemical use should be considered industry confidential business information and therefore protected from public disclosure. The commenter also noted that chemical suppliers or distributors do not typically have visibility to end use, particularly specific end use categories.

Response: As discussed in section VI. of this preamble, we are planning to finalize our proposed determination that the two new subpart OO data elements (the end use(s) to which the N_2O, SF_6, each PFC, or each fluorinated HTF is transferred and the aggregated annual quantity of the GHG that is transferred to that end use application) are ''Eligible for Confidential Treatment.'' This will protect the data from public disclosure. Regarding suppliers' knowledge of the uses of compounds within each industry, suppliers are required to report the end uses only ''if known.'' For N_2O, SF_6, and saturated PFCs, the end uses that we identified in the proposed rule coincided with individual industries and not specific uses within those industries. For fluorinated HTFs, the end uses that we identified in the proposed rule coincided with some specific uses within industries, such as cleaning versus temperature control within the electronics industry. This was because different end uses, even within the same industry, have different emission patterns, which affect the relationship between emissions and consumption of these compounds. (For example, end uses that quickly emit the F–HTF, such as cleaning, are expected to have emissions that are close to consumption, whereas end uses that store the F–HTF, such as process cooling, may have emissions that are less than half of consumption.) However, the electronics industry, unlike other industries that use F–HTFs, reports its F–HTF emissions to EPA. Thus, in the subpart OO electronic reporting form, we are planning to list ‘‘electronics manufacturing’’ (including manufacturing of semiconductors, MEMS, photovoltaic cells, and displays), and not specific uses within electronics manufacturing, among the end uses whose consumption of the fluorinated HTF will be reported.

V. Subpart PP—Suppliers of Carbon Dioxide

We are finalizing several amendments to subpart PP of part 98 (Suppliers of Carbon Dioxide) as proposed. This section discusses the final revisions to subpart PP. The EPA received comments on the proposed revisions to subpart PP. See the document ‘‘Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule’’ in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart PP.

The EPA is finalizing several revisions to subpart PP to improve the quality of the data collected from this subpart. As proposed, we are adding new 40 CFR 98.420(a)(4) and a new definition to 40 CFR 98.6 to explicitly include direct air capture (DAC) as a capture option under subpart PP. Unlike conventional capture sources where CO_2 is separated during the manufacturing or treatment phase of product stream, DAC captures CO_2 from ambient air using aqueous or solid sorbents, which is then processed into a concentrated stream for utilization or injection underground. This final rule provides that DAC, ‘‘with respect to a facility, technology, or system, means that the facility, technology, or system uses carbon capture equipment to capture carbon dioxide directly from the air. DAC does not include any facility, technology, or system that captures carbon dioxide (1) that is deliberately released from a naturally occurring subsurface spring or (2) using natural photosynthesis.’’

The EPA is also finalizing an amendment to the definition of ‘‘carbon dioxide stream’’ in 40 CFR 98.6 to add ‘‘captured from ambient air (*e.g.,* direct air capture)’’ to the definition so that it reads, ‘‘Carbon dioxide stream means carbon dioxide that has been captured from an emission source (*e.g.,* a power plant or other industrial facility), captured from ambient air (*e.g.,* direct air capture), 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.’’

We are finalizing harmonizing changes to 40 CFR 98.422, 98.423, 98.426, and 98.427 to add references to DAC into the reporting requirements. The final rule also amends 40 CFR 98.426 as proposed to add additional reporting requirements in paragraph (i) to require DAC facilities to report the annual quantities and sources (*e.g.,* non-hydropower renewable sources, natural gas, oil, coal) of on-site and off-site sourced electricity, heat, and combined heat and power used to power the DAC plant. These quantities must represent the electricity and heat used starting from the air intake at the facility and ending with the compressed CO_2 stream (*i.e.,* the CO_2 stream ready for supply for commercial applications or, if maintaining custody of the stream, sequestration or injection of the stream underground). These quantities must be provided per energy source, if known. For electricity provided to the DAC plant from the grid, reporters must additionally provide identifying information for the facility and electric utility company. In addition, for on-site sourced electricity, heat, and combined heat and power, DAC facilities must indicate whether flue gas is also captured by the DAC process unit. These changes will aid the EPA in understanding this emerging technology at facilities that utilize DAC and in better understanding potential net emissions impacts associated with DAC facilities (particularly given that interest in DAC is primarily intended to be a carbon removal technology to achieve climate benefits). See section III.T. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on the EPA's rationale for these changes.

The EPA is finalizing two additional revisions to improve data quality. First, we are finalizing the addition of a data element to 40 CFR 98.426(f) that will require suppliers to report the annual quantity of CO_2 in metric tons that is transferred for use in geologic sequestration with EOR subject to new subpart VV to part 98 (Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916). To inform the revision of the subpart PP electronic reporting form, the EPA also sought comment on potential end use applications to add to 40 CFR 98.426(f), such as algal systems, chemical production, and mineralization processes, such as the production of cements, aggregates, or bicarbonates. However, because 40 CFR 98.426(f) already includes a reporting category for ‘‘other,’’ the existing rule already provides flexibility for this reporting, and we are not taking final action on the addition of specific end-use applications to 40 CFR 98.426 at this time. The EPA may consider the addition of other end-use applications in a future rulemaking.

Second, the EPA is finalizing as proposed that 40 CFR 98.426(h) will apply to any facilities that capture a CO_2 stream from a facility subject to 40 CFR part 98 and supply that CO_2 stream to facilities that are subject to either subpart RR (Geologic Sequestration of Carbon Dioxide) or new subpart VV. The revised paragraph will no longer apply only to suppliers that capture CO_2 from EGUs subject to subpart D (Electricity Generation), but also to suppliers that capture CO_2 from any direct emitting facility that is subject to 40 CFR part 98 and transfer to facilities subject to subparts RR or VV. Reporters must provide the facility identification number associated with the facility that is the source of the captured CO_2 stream, each facility identification number associated with the annual GHG reports for each subpart RR and subpart VV facility to which CO_2 is transferred, and the annual quantity of CO_2 transferred to each subpart RR and VV facility. See section III.L. of the preamble to the 2023 Supplemental Proposal for additional information.

The EPA also requested comment on, but did not propose, expanding the requirement at 40 CFR 98.426(h) such that facilities subject to subpart PP would report transfers of CO_2 to any facilities reporting under 40 CFR part 98, not just those subject to subparts RR and VV. This would include reporting the amount of CO_2 transferred on an annual basis as well as the relevant GHGRP facility identification numbers. The EPA further requested comment on whether information regarding additional end uses would be available to facilities. Following consideration of public comments, we are not extending the reporting requirements at this time but may consider doing so in a future rulemaking.

We are finalizing, with revisions, related confidentiality determinations for data elements resulting from the revisions to subpart PP as described in section VI. of this preamble.

W. Subpart QQ—Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment and Closed-Cell Foams

We are finalizing the amendments to subpart QQ of part 98 (Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged

Equipment and Closed-Cell Foams) as proposed. In some cases, we are finalizing the proposed amendments with revisions. Section III.W.1. discusses the final revisions to subpart QQ. The EPA received several comments on proposed subpart QQ revisions which are discussed in section III.W.2. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the final revisions to subpart QQ, as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart QQ

This section summarizes the final amendments to subpart QQ. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart QQ can be found in this section and section III.W.2. of this preamble. Additional rationale for these amendments are available in the preamble to the 2023 Supplemental Proposal.

We are finalizing two revisions from the 2023 Supplemental Proposal. We are finalizing requirements for importers and exporters of fluorinated GHGs contained in pre-charged equipment or closed-cell foams to include, for each import and export, the HTS code (for importers, at 40 CFR 98.436(a)(7)) and the Schedule B code (for exporters, at 40 CFR 98.436(b)(7)) used for shipping each equipment type. These requirements are consistent with the final revisions to subpart OO of part 98 (Suppliers of Industrial Greenhouse Gases), which clarify that reporters should submit the HTS code for each shipment, as discussed in section III.U. of this preamble. See section III.S. of the preamble to the 2023 Supplemental Proposal for additional information on the EPA's rationale for these changes.

The EPA also proposed to revise 40 CFR 98.436 to add a requirement to include collecting copies of the U.S. CBP entry form (*e.g.,* CBP form 7501) for each reported import, which are currently maintained as records under 40 CFR 98.437(a). Following consideration of public comments, the EPA is not taking final action on the proposed requirement to submit copies of each U.S. CBP entry form. See section III.W.2. of this preamble for a summary of the related comments and the EPA's response.

2. Summary of Comments and Responses on Subpart QQ

This section summarizes the major comments and responses related to the proposed amendments and supplemental amendments to subpart QQ. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart QQ.

Comment: Several commenters contested the EPA's proposed requirements to collect a copy of the corresponding U.S. CBP entry form (*e.g.,* Form 7501) for each reported import in 40 CFR 98.436. Some commenters asserted that the information available in the forms is currently provided electronically to CBP through the Automated Commercial Environment (ACE) and should be available to the EPA within the need for reporters to develop or submit copies. The commenters noted that this information should be sufficient to identify which entries are subject to data requirements under subpart QQ. Commenters recommended that the EPA should coordinate with CBP through established bodies (*e.g.,* the Border Interagency Executive Council and Commercial Targeting and Analysis Center, to which the EPA already participates) to identify and utilize this data. One commenter specifically recommended that the EPA review the Entry Summary Line Detail Report, which would show the total quantity reported for entry summary lines by tariff number for the reported unit of measure. The commenters stated that such reports capture the actual data in CBP's system, as filed by importers, and should be sufficient to ensure that the Agency is able to improve the verification and accuracy of the data it collects. One commenter expressed that if the EPA is unable to identify applicable entries through more efficient means, importers should only be asked to identify specific entry numbers that will allow the EPA to identify the applicable electronic submissions within ACE.

Commenters objected to the implied submission of hard-copy entry records as an unnecessary administrative burden. Commenters stated that the proposed requirement runs counter to CBP's longstanding effort to collect import data and documents electronically. One commenter stated that submittal of the border crossing document would necessitate a substantial amount of additional work and resources to comply, including gathering documentation from multiple sources prior to annual reporting. Another commenter noted that in some cases, importers could be required to file over 70,000 entries or forms. One commenter stated that this would require at least 1,300 manual searches for the appropriate forms for each entry. Commenters urged that this would be prohibitively expensive and burdensome. One commenter pointed out that this would require substantial modifications to automakers' existing information systems and processes for their GHG and related reporting obligations. Other commenters noted that paper form requirements would obfuscate industry efforts to further automate their record-keeping and reporting systems. One commenter added that the increased volume of documentation would likely put much more pressure on businesses than they can manage based on the current requirement to file data by March 31st of the year following the reporting year.

One commenter stated that the CBP forms would merely confirm the amount of foam board imported or exported and would not validate the F–GHG quantity which is the intent of the report. The commenter continued that, even if border documents were provided, it would be impossible for the EPA to validate the current reports as the calculations involved to provide the volume of F–gas per board foot would require detailed technical knowledge, including density of the foam board.

Some commenters asserted that the entry form requirement runs counter to Executive Order 13659 and 19 U.S.C. 1411(d), as amended by sections 106 and 107 of the Trade Facilitation and Trade Enforcement Act of 2015, which advance the goal of providing for electronic transmission of import data and seek to eliminate the need for duplicative information submissions across U.S. government agencies with regulatory authority related to goods entered or imported into the United States.

Other commenters questioned the EPA's requirements to require reporting of the HTS) code for each type of pre-charged equipment or closed-cell foam imported and/or the Schedule B code for each type of pre-charged equipment or closed-cell foam exported. One commenter questioned whether the inclusion of both HTS codes and Schedule B codes is necessary for validation of the data that is currently collected, as all polystyrene foams use the same codes. The commenter urged that requiring more than one type of document would prove redundant in showing product type; be burdensome for manufacturers and for the EPA; and would not provide any additional clarity or validation to the current report.

Another commenter stated that only the border crossing document (which includes the customs tariff number, with the first six digits of an HTS and Schedule B number) should be required as part of the annual report. The commenter noted that these border crossing documents share highly sensitive information such as quantity and price, so should be handled securely. One commenter reiterated that all data proposed to be collected is, and would be, considered highly confidential business information. The commenter added that access to this type of information is restricted internally, which adds complexity to who could manage and deal with the processing of this documentation within facilities.

Response: The EPA is revising the final rule to remove the requirement for reporters to submit copies of their U.S. CBP form 7501. Following consideration of comments received, it has been determined that annually reporting these documents could pose a significant burden for many reporters. Therefore, the EPA is not adopting the proposed data reporting requirement in the final rule.

The EPA is finalizing the proposed requirement to report HTS codes (for imports) and Schedule B codes (for exports) to assist the Agency in verification of data. This requirement will allow the EPA to better compare reported GHGRP data with data from other government sources, specifically CBP records. As only one type of code (HTS or Schedule B) will be required based on whether the shipment is an import or export, this will not require the reporting of redundant information to the EPA. Furthermore, we are making ''No Determination'' of confidentiality for this data element. ''No Determination'' means that the EPA is not making a confidentiality determination through rulemaking at this time. If necessary, the EPA will evaluate and determine the confidentiality status of this data on a per-facility basis in accordance with the provisions of 40 CFR part 2, subpart B.

X. Subpart RR—Geologic Sequestration of Carbon Dioxide

We are finalizing amendments to subpart RR of part 98 (Geologic Sequestration of Carbon Dioxide) as proposed. This section discusses the substantive final revisions to subpart RR. The EPA received only one supportive comment for subpart RR. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart RR. Additional rationale for these amendments is available in the preamble to the 2023 Supplemental Proposal.

We are adding a definition for ''offshore'' to 40 CFR 98.449 to mean ''seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.'' This definition clarifies the applicability of subpart RR to offshore geologic sequestration activities, including on the outer continental shelf. Additional rationale for these amendments is available in the preamble to the 2023 Supplemental Proposal.

Y. Subpart SS—Electrical Equipment Manufacture or Refurbishment

We are finalizing several amendments to subpart SS of part 98 (Electrical Equipment Manufacture or Refurbishment) as proposed. In some cases, we are finalizing the proposed amendments with revisions. Section III.Y.1. of this preamble discusses the substantive final revisions to subpart SS. The EPA received several comments on the proposed revisions to subpart SS which are addressed in section III.Q.2. of this preamble. We are also finalizing as proposed confidentiality determinations for new data elements resulting from the revisions to subpart SS as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart SS

This section summarizes the final amendments to subpart SS. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other final revisions to 40 CFR part 98, subpart SS can be found in this section and section III.Y.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal.

a. Revisions To Improve the Quality of Data Collected for Subpart SS

The EPA is finalizing several revisions to subpart SS to improve the quality of the data collected from this subpart. We are generally finalizing as proposed revisions to the calculation, monitoring, and reporting requirements of subpart SS (at 40 CFR 98.452, 98.453, 98.454, and 98.456) to require reporting of additional F–GHGs as defined under 40 CFR 98.6, except electrical equipment manufacturers and refurbishers will not be required to report emissions of insulating gases with weighted average GWPs of one (1) or less. However, they will be required to report the quantities of insulating gases with weighted average GWPs of one or less, as well as the nameplate capacities of the associated equipment, that they transfer to their customers. To implement these revisions, we are finalizing revisions that redefine the source category at 40 CFR 98.450 to include equipment containing ''fluorinated GHGs (F–GHG), including but not limited to sulfur-hexafluoride (SF_6) and perfluorocarbons (PFCs).'' The changes also apply to the threshold in 40 CFR 98.451, which we are revising as discussed in section III.Y.1. of this preamble. Facilities also must consider additional F–GHGs purchased by the facility in estimating emissions for comparison to the threshold.

The revisions to subpart SS include the addition of a new equation SS–1 in the reporting threshold at 40 CFR 98.451 (discussed in section III.Y.b. of this preamble) and a new equation SS–2 in the GHGs to report at 40 CFR 98.452. Equation SS–2 is also used in the definition of ''reportable insulating gas,'' discussed in this section of the preamble. We are also making minor revisions to equations SS–1 through SS–6 (which we are renumbering as SS–3 through SS–8 to accommodate new equations SS–1 and SS–2) to incorporate the estimation of emissions from all F–GHGs within the existing calculation methodology. To account for the possibility that the same fluorinated GHG could be a component of multiple reportable insulating gases, we are inserting in the final rule a summation sign at the beginning of the right side of equation SS–3 to ensure that emissions of each fluorinated GHG i are summed across all reportable insulating gases j. In addition, we are updating the monitoring and quality assurance requirements to account for emissions from additional F–GHGs, and harmonizing revisions to the reporting requirements such that reporters account for the mass of each F–GHG at the facility level.

We are also finalizing the proposed definition of ''insulating gas'' and adding the term ''reportable insulating gas,'' which is defined as ''an insulating gas whose weighted average GWP, as calculated in equation SS–2, is greater than one. A fluorinated GHG that makes up either part or all of a reportable insulating gas is considered to be a component of the reportable insulating gas.'' This term is intended to distinguish between insulating gases whose emissions must be reported under subpart SS and insulating gases whose emissions are not required to be reported under subpart SS (although, as noted above, the quantities of all insulating gases supplied to customers must be reported). In many though not all cases, we are also replacing occurrences of the proposed phrase ''fluorinated GHGs, including PFCs and SF_6'' with ''fluorinated GHGs that are components of reportable insulating gases.'' In addition, we are finalizing revisions to add reporting of an ID number or descriptor for each insulating gas and the name and weight percent of each insulating gas reported. The EPA has also made one minor clarification from proposal. We initially proposed 40 CFR 98.456(u) to require reporting of an ID number or descriptor for each unique insulating gas. To clarify the applicability of this requirement for those gases mixed on-site, the final rule clarifies that facilities must report an ID number or other appropriate descriptor that is unique to the reported insulating gas, and for each ID number or descriptor reported, the name and weight percent of each fluorinated gas in the insulating gas. See section III.U.1. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these revisions and their supporting basis.

b. Revisions To Streamline and Improve Implementation for Subpart SS

To account for changes in the usage of certain GHGs and reduce the likelihood that the reporting threshold will cover facilities with emissions well below 25,000 $mtCO_2e$, we are generally finalizing revisions to the applicability threshold of subpart SS as proposed. (The one change is the introduction of the term ''reportable insulating gas,'' as described in this section III.Y. of the preamble.) The revisions remove the consumption-based threshold at 40 CFR 98.451 and instead require facilities to estimate total annual GHG emissions for comparison to the 25,000 $mtCO_2e$ threshold by introducing a new equation, equation SS–1. The equation SS–1 continues to be based on the total annual purchases of insulating gases, but establishes an updated comparison to the threshold, and accounts for the additional fluorinated gases reported by industry. Potential reporters are required to account for the total annual purchases of all reportable insulating gases and multiply the purchases of each reportable insulating gas by the GWP for each F–GHG and the emission factor of 0.10 (or 10 percent). The final rule threshold methodology is more appropriate because it represents the actual fluorinated gases used by a reporter; these revisions also streamline the reporting requirements to focus Agency resources on the substantial emission sources within the sector. Additionally, the changes revise the inclusion of subpart SS in the existing table A–3 to subpart A. Because we are providing a method for direct comparison to the 25,000 $mtCO_2e$ threshold, we are removing subpart SS from table A–3 and including the subpart in table A–4 to subpart A. This will require facilities to determine applicability according to 40 CFR 98.2(a)(2) and consider the combined emissions from stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and other applicable source categories. Including subpart SS in table A–4 to subpart A is consistent with other GHGRP subparts that use the 25,000 $mtCO_2e$ threshold included under 40 CFR 98.2(a)(2) to determine applicability. See section III.U.2. of the preamble to the 2022 Data Quality Improvements Proposal for additional information on these revisions and their supporting basis.

2. Summary of Comments and Responses on Subpart SS

This section summarizes the major comments and responses related to the proposed amendments to subpart SS. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart SS.

Comment: One commenter suggested redefining the definition of ''insulating gas'' to including any gas with a GWP greater than one and not any fluorinated GHG or fluorinated GHG mixture. The commenter urged that the proposed definition ignores other potential gases that may come onto the market that are not fluorinated but still have a GWP potential. The commenter stated that defining insulating gas under subpart SS to include any gas with a GWP greater than one used as an insulating gas and/or arc quenching gas in electrical equipment would mirror the threshold implemented by the California Air Resources Board and would provide consistency for reporters across Federal and State reporting rules.

Response: In the final rule, the EPA is not requiring electrical equipment manufacturers and refurbishers to report emissions of insulating gases with weighted average 100-year GWPs of one or less, but the EPA is requiring such facilities to report the quantities of insulating gases with GWPs of one or less, as well as the nameplate capacity of the associated equipment, that they transfer to their customers. Based on a review of the subpart SS data submitted to date, the EPA has concluded that excluding emissions of insulating gases with weighted average GWPs of one or less from reporting under subpart SS will have little effect on the accuracy or completeness of the GWP-weighted totals reported under subpart SS or under the GHGRP generally. Between 2011 and 2021, total SF_6 and PFC emissions across all facilities reporting under subpart SS have ranged from 5 to 15 mt (unweighted) or 120,000 to 350,000 $mtCO_2e$. At GWPs of one, these weighted totals would be equivalent to the unweighted quantities reported, which constitute approximately 0.004% (1/23,500) of the GWP-weighted totals. Even in a worst-case scenario where the annual manufacturer emissions of a very low-GWP insulating gas were assumed to equal the total quantity of that gas transferred from manufacturers to customers (implying an emission rate of 100%, higher than any ever reported under subpart SS), the total GWP-weighted emissions reported under subpart SS would be considerably smaller than those reported under any other subpart: total unweighted quantities shipped to customers reported across all facilities to date have ranged between 196 and 372 mt. At GWPs of 1, these totals would fall well below the 15,000- and 25,000 $mtCO_2e$ quantities below which individual facilities are eventually allowed to exit the program under the off-ramp provisions of subpart A of part 98 (40 CFR 98.2(i)), as applicable.

While the EPA is not requiring electrical equipment manufacturers and refurbishers to report their emissions of insulating gases with GWPs of one or less, the EPA is requiring such facilities to report the quantities of insulating gases with weighted average GWPs of one or less, as well as the nameplate capacity of the associated equipment, that they transfer to their customers. Tracking such transfers is important to understanding the extent to which substitutes for SF_6 are replacing SF_6 as an insulating gas, which will inform future policies and programs under provisions of the CAA. The EPA anticipates that tracking transfers to customers will involve a lower burden than tracking emissions and other quantities in addition to transfers.

Z. Subpart UU—Injection of Carbon Dioxide

We are finalizing the amendments to subpart UU of part 98 (Injection of Carbon Dioxide) as revised in the 2023 Supplemental Proposal. This section discusses the final revisions to subpart UU. The EPA received only one supportive comments on the proposed revision to subpart UU in the 2023 Supplemental Proposal. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart UU.

The EPA initially proposed amendments to subpart UU in the 2022 Data Quality Improvements Proposal that were intended to harmonize with revisions to add new subpart VV to part 98 (Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916). Subpart VV is described further in section III.Z. of this preamble. However, we received comments on the 2022 Data Quality Improvements Proposal saying that the applicability of proposed subpart VV was unclear. The EPA subsequently re-proposed revisions to 40 CFR 98.470 in the 2023 Supplemental Proposal. As described in sections III.O. of the preamble of the 2023 Supplemental Proposal, the EPA proposed, and is finalizing, revisions to § 98.470 of subpart UU of part 98 to clarify the applicability of each subpart when a facility quantifies their geologic sequestration of CO_2 in association with EOR operations through the use of the CSA/ANSI ISO 27916:19 method. Specifically, we are clarifying that facilities with a well or group of wells that must report under subpart VV shall not also report data for those same wells under subpart UU. These changes also clarify how CO_2–EOR projects that may transition to use of the CSA/ANSI ISO 27916:19 method during a reporting year will be required to report for the portion of the reporting year before they began using CSA/ANSI ISO 27916:19 and for the portion after they began using CSA/ANSI ISO 27916:19. Additional rationale for these amendments is available in the preamble to the 2023 Supplemental Proposal.

AA. Subpart VV—Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916

We are finalizing several amendments to add subpart VV (Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916) to part 98 as proposed. Section III.Z.1. of this preamble discusses the final requirements of subpart VV. The EPA received several comments on the proposed subpart VV which are discussed in section III.V.2. of this preamble. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the revisions to subpart VV as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart VV

This section summarizes the substantive final amendments to subpart VV. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart VV can be found in this section. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal 2023 Supplemental Proposal.

a. Source Category Definition

In the 2022 Data Quality Improvements Proposal, the EPA proposed adding a new source category, subpart VV, to part 98 to add calculation and reporting requirements for quantifying geologic sequestration of CO_2 in association with EOR operations, which would only apply to facilities that quantify the geologic sequestration of CO_2 in association with EOR operations in conformance with the ISO standard designated as CSA/ANSI ISO 27916:19, *Carbon dioxide capture, transportation and geological storage—Carbon dioxide storage using enhanced oil recovery.*[42] In our initial proposal, the EPA outlined the source category definition, rationale for no threshold, calculation methodology, and monitoring, recordkeeping, and reporting requirements. We noted at that time that under existing GHGRP requirements, facilities that receive CO_2 for injection at EOR operations report under subpart UU (Injection of Carbon Dioxide), and facilities that geologically sequester CO_2 through EOR operations may instead opt-in to subpart RR (Geologic Sequestration of Carbon Dioxide). The EPA proposed to add new subpart VV to require reporting of incidental CO_2 storage associated with EOR based on the CSA/ANSI ISO 27916:19 standard. We subsequently received detailed comments saying that the applicability of proposed subpart VV was unclear, specifically, proposed 40 CFR 98.480 ''Definition of the Source Category.'' The commenters were uncertain whether the EPA had intended to require facilities using CSA/ANSI ISO 27916:19 to report under subpart VV or whether facilities that used CSA/ANSI ISO 27916:19 would have the option to choose under which subpart they would report to: subpart RR, subpart UU, or subpart VV.

In the 2023 Supplemental Proposal, the EPA subsequently reproposed §§ 98.480 and 98.481 of subpart VV to clarify the applicability to each subpart. As explained in section III.P. of the preamble the 2023 Supplemental Proposal, the EPA clarified that if a facility elects to use the CSA/ANSI ISO 27916:19 method for quantifying geologic sequestration of CO_2 in association with EOR operations, then the facility would be required under the GHGRP to report under new subpart VV (unless the facility chooses to report under subpart RR and has received an approved Monitoring, Reporting, and Verification Plan (MRV Plan) from EPA). The EPA further clarified that subpart VV is not intended to apply to facilities that use the content of CSA/ANSI ISO 27916:19 for a purpose other than demonstrating secure geologic storage, such as only as a reference material or for informational purposes. Following review of subsequent comments received on the reproposed source category definition, we are finalizing the definition of the source category as proposed in the 2023 Supplemental Proposal.

b. Reporting Threshold

In the 2022 Data Quality Improvements Proposal, the EPA proposed no threshold for reporting under subpart VV (*i.e.,* that subpart VV would be an ''all-in'' reporting subpart). The EPA also proposed under 40 CFR 98.480(c) that facilities subject only to subpart VV would not be required to report emissions under subpart C or any other subpart listed in 40 CFR 98.2(a)(1) or (2), consistent with the requirements for existing reporters under subpart UU. In the 2023 Supplemental Proposal, the EPA maintained no threshold is required for reporting, but amended the regulatory text to clarify that all CO_2–

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[42] Although the title of the standard references only EOR, Clause 1.1 of CSA/ANSI ISO 27916:19 indicates that the standard can apply to enhanced gas recovery as well. Therefore, any reference to EOR in subpart VV also applies to enhanced gas recovery.

EOR projects using CSA/ANSI ISO 27916:19 as a method of quantifying geologic sequestration that do not report under subpart RR would report under subpart VV. We also proposed text at 40 CFR 98.481(c) to clarify how CO_2–EOR projects previously reporting under subpart UU that begin using CSA/ANSI ISO 27916:19 part-way through a reporting year must report. The EPA is finalizing these requirements as reproposed in the 2023 Supplemental Proposal.

Additionally, we are finalizing revisions at 40 CFR 98.481(b) that facilities subject to subpart VV will not be subject to the off-ramp requirements of 40 CFR 98.2(i). Instead, once a facility opts-in to subpart VV, the owner or operator must continue for each year thereafter to comply with all requirements of the subpart, including the requirement to submit annual reports, until the facility demonstrates termination of the CO_2–EOR project following the requirements of CSA/ANSI ISO 27916:19. The operator must notify the Administrator of its intent to cease reporting and provide a copy of the CO_2–EOR project termination documentation prepared for CSA/ANSI ISO 27916:19.

c. Calculation Methods

In the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal, the EPA proposed incorporating the quantification methodology of CSA/ANSI ISO 27916:19 for calculation of emissions. Under CSA/ANSI ISO 27916:19, the mass of CO_2 stored is determined as the total mass of CO_2 received minus the total mass of CO_2 lost from project operations and the mass of CO_2 lost from the EOR complex. The EOR complex is defined as the project reservoir, trap, and such additional surrounding volume in the subsurface as defined by the operator within which injected CO_2 will remain in safe, long-term containment. Specific losses include those from leakage from production, handling, and recycling facilities; from infrastructure (including wellheads); from venting/flaring from production operations; and from entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected. We are finalizing the calculation requirements as proposed.

d. Monitoring, QA/QC, and Verification Requirements

The EPA is finalizing as proposed the requirement for reporters to use the applicable monitoring and quality assurance requirements set forth in CSA/ANSI ISO 27916:19.

e. Procedures for Estimating Missing Data

The EPA is finalizing as proposed the requirement for reporters to use the applicable missing data and quality assurance procedures set forth in CSA/ANSI ISO 27916:19.

f. Data Reporting Requirements

The EPA is finalizing, as proposed, that facilities will report the amount of CO_2 stored, inputs included in the mass balance equation used to determine CO_2 stored using the CSA/ANSI ISO 27916:19 methodology, and documentation providing the basis for that determination as set forth in CSA/ANSI ISO 27916:19. Documentation includes providing the CSA/ANSI ISO 27916:19 EOR Operations Management Plan (OMP), which is required to specify: (1) a geological description of the site and the procedures for field management and operational containment during the quantification period; (2) the initial containment assurance plan to identify potential leakage pathways; (3) the plan for monitoring of potential leakage pathways; and (4) the monitoring methods for detecting and quantifying losses and how this will serve to provide the inputs into site-specific mass balance equations. Reporters must also specify any changes made to containment assurance and monitoring approaches and procedures in the EOR OMP made within the reporting year.

We are also finalizing the reporting of the following information per CSA/ANSI ISO 27916:19: (1) the quantity of CO_2 stored during the year; (2) the formula and data used to quantify the storage, including the quantity of CO_2 delivered to the CO_2–EOR project and losses during the year; (3) the methods used to estimate missing data and the amounts estimated; (4) the approach and method for quantification utilized by the operator, including accuracy, precision and uncertainties; (5) a statement describing the nature of validation or verification, including the date of review, process, findings, and responsible person or entity; and (6) the source of each CO_2 stream quantified as storage. The final rule also requires that reporters provide a copy of the independent engineer or geologist's certification as part of reporting to subpart VV, if such a certification has been made.

Finally, the EPA is finalizing a notification for project termination. The final rule specifies that the time for cessation of reporting under subpart VV is the same as under CSA/ANSI ISO 27916:19; the operator must notify the Administrator of its intent to cease reporting and provide a copy of the CO_2–EOR project termination documentation.

g. Records That Must Be Retained

The EPA is finalizing as proposed the requirement that reporters meet the record retention requirements of 40 CFR 98.3(g) and the applicable recordkeeping retention requirements set forth in CSA/ANSI ISO 27916:19.

2. Summary of Comments and Responses on Subpart VV

The EPA received several comments for subpart VV; the majority of these comments were received on the 2022 Data Quality Improvements Proposal and were previously addressed in the preamble to the 2023 Supplemental Proposal (see section III.P. of the preamble to the 2023 Supplemental Proposal). The EPA received only supportive comments on the proposed revisions to subpart VV in the 2023 Supplemental Proposal; see the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart VV.

BB. Subpart WW —Coke Calciners

We are finalizing the addition of subpart WW to part 98 (Coke Calciners) with revisions in some cases. Section III.BB.1. of this preamble discusses the final requirements of subpart WW. The EPA received several comments on the proposed subpart WW which are discussed in section III.BB.2. of this preamble. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the revisions to subpart WW as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart WW

This section summarizes the substantive final amendments to subpart WW. Major changes in this final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart WW can be found in this section. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Source Category Definition

The EPA is finalizing the source category definition as proposed, with one minor clarification. Specifically, we proposed that the coke calciner source category consists of process units that heat petroleum coke to high temperatures in the absence of air or oxygen for the purpose of removing impurities or volatile substances in the petroleum coke feedstock. Following review of comments received, the EPA is revising the source category definition from that proposed to remove the language ‘‘in the absence of air or oxygen.’’ See section III.BB.2. of this preamble for additional information on related comments and the EPA's response. The final definition of the coke calciner source category includes, but is not limited to, rotary kilns or rotary hearth furnaces used to calcine petroleum coke and any afterburner or other equipment used to treat the process gas from the calciner. The source category includes all coke calciners, not just those co-located at petroleum refineries, to provide consistent requirements for all coke calciners.

b. Reporting Threshold

In the 2023 Supplemental Proposal, the EPA proposed no threshold for reporting under subpart WW. Because coke calciners are large emission sources, they are expected to emit over the 25,000 $mtCO_2e$ threshold generally required to report under existing GHGRP subparts with thresholds, and nearly all of them are also projected to exceed the 100,000 $mtCO_2e$ threshold. Therefore, the EPA projects that there are limited differences in the number of reporting facilities based on any of the emission thresholds considered. For this reason, the EPA is finalizing the coke calciner source category as an ‘‘all-in'' subpart (*i.e.,* regardless of their emissions profile).

c. Calculation Methods

Coke calciners primarily emit CO_2, but also have CH_4 and N_2O emissions as part of the process gas emission control combustion device operation. The EPA is finalizing, as proposed in the 2023 Supplemental Proposal, that CO_2, CH_4, and N_2O emissions from each coke calcining unit be estimated.

The EPA reviewed a number of different emissions estimation methods for coke calciners. We subsequently proposed, and are finalizing, to require either one of two separate calculation methods, the use of a CEMS or the carbon mass balance method for estimating emissions. Each of these methodologies are used to estimate CO_2 emissions. We are also finalizing, as proposed, that coke calciners also estimate process CH_4 and N_2O emissions based on the total CO_2 emissions determined for the coke calciner and the ratio of the default CO_2 emission factor for petroleum coke in table C–1 to subpart C of part 98 to the default CH_4 and N_2O emission factors for petroleum products in table C–2 to subpart C of part 98. Under the final methods, petroleum refineries with coke calciners are able to maintain their current calculation methods. Additional detail on the calculation methods reviewed are available in section IV.B. of the preamble to the 2023 Supplemental Proposal.

Direct measurement using CEMS. The CEMS approach directly measures CO_2 concentration and total exhaust gas flow rate for the combined process and combustion source emissions. CO_2 mass emissions are calculated from these measured values using equation C–6 and, if necessary, equation C–7 in 40 CFR 98.33(a)(4).

The EPA proposed that the CEMS method under subpart WW would be implemented consistent with subpart Y of part 98 (Petroleum Refineries), which required reporters to determine CO_2 emissions from auxiliary fuel use discharged in the coke calciner exhaust stack using methods in subpart C of part 98, and to subtract those emissions from the measured CEMS emissions to determine the process CO_2 emissions. We are finalizing this requirement.

Carbon balance method. For those facilities that do not have a qualified CEMS in-place, facilities may use the carbon mass balance method, using data that is expected to be routinely monitored by coke calcining facilities. The carbon mass balance method uses the mass of green coke, calcined coke and petroleum coke dust removed from the dust collection system, along with the carbon content of the green and calcined coke, to estimate process CO_2 emissions; the methodology is the same as current equation Y–13 of 40 CFR 98.253(g)(2) that is used for coke calcining processes co-located at petroleum refineries.

d. Monitoring, QA/QC, and Verification Requirements

The EPA is finalizing the monitoring methods to subpart WW as proposed.

Direct measurement using CEMS. For direct measurement using CEMS, the CEMS method requires both a continuous CO_2 concentration monitor and a continuous volumetric flow monitor. Reporters required to or electing to use CEMS must install, operate, and calibrate the monitoring system according to subpart C (General Stationary Fuel Combustion Sources), which is consistent with the current requirements for coke calciner CO_2 CEMS monitoring requirements within subpart Y. We are finalizing that all CO_2 CEMS and flow rate monitors used for direct measurement of GHG emissions should comply with QA/QC procedures for daily calibration drift checks and quarterly or annual accuracy assessments, such as those provided in Appendix F to part 60 or similar QA/QC procedures. These requirements ensure the quality of the reported GHG emissions and are consistent with the current requirements for CEMS measurements within subparts A (General Provisions) and C of the GHGRP.

Carbon balance method. The carbon mass balance method requires monitoring of mass quantities of green coke fed to the process, calcined coke leaving the process, and coke dust removed from the process by dust collection systems. It also requires periodic determination of carbon content of the green and calcined coke. For coke mass measurements, we are finalizing that the measurement device be calibrated according to the procedures specified by the updated NIST HB 44–2023: *Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices,* 2023 edition (we have clarified the title and publication date of this method in the final rule) or the procedures specified by the manufacturer. We are requiring the measurement device be recalibrated either biennially or at the minimum frequency specified by the manufacturer. These requirements are to ensure the quality of the reported GHG emissions and to be consistent with the current requirements for coke calciner mass measurements within subpart Y.

For carbon content of coke measurements, the owner or operator must follow approved analytical procedures and maintain and calibrate instruments used according to manufacturer's instructions and to document the procedures used to ensure the accuracy of the measurement devices used. These requirements are to ensure the quality of the reported GHG emissions and to be consistent with the current requirements for coke calciner mass measurements within subpart Y. These determinations must be made monthly. If carbon content measurements are made more often than monthly, all measurements made within the calendar month must be used to determine the average for the month.

e. Procedures for Estimating Missing Data

The EPA is finalizing as proposed the procedures for estimating missing data. For the CEMS methodology, 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. For missing CEMS data, the missing data procedures in subpart C must be used.

Under the carbon mass balance method, for each missing value of mass or carbon content of coke, reporters must use the average of the data measurements before and after the missing data period. If, for a particular parameter, no quality assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period. Similarly, if no quality-assured data are available after the missing data incident, the substitute data value must be the most recently acquired quality-assured value obtained prior to the missing data period.

f. Data Reporting Requirements

The EPA is finalizing the data reporting requirements of subpart WW as proposed. For coke calcining units, the owner and operator shall report the coke calciner unit ID number and maximum rated throughput of the unit, the method used to calculate GHG emissions, and the calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted. We are also requiring the owner and operator to report the annual mass of green coke fed to the coke calcining unit, the annual mass of marketable petroleum coke produced by the coke calcining unit, the annual mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit, the annual average mass fraction carbon content of green coke fed to the unit, and the annual average mass fraction carbon content of the marketable petroleum coke produced by the coke calcining unit.

g. Records That Must Be Retained

The EPA is finalizing the record retention requirements of subpart WW as proposed. Facilities are required to maintain records documenting the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

For the coke calciners source category, we are finalizing that the verification software specified in 40 CFR 98.5(b) be used to fulfill the recordkeeping requirements for the following five data elements:

- Monthly mass of green coke fed to the coke calcining unit;
- Monthly mass of marketable petroleum coke produced by the coke calcining unit;
- Monthly mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit;
- Average monthly mass fraction carbon content of green coke fed to the coke calcining unit; and
- Average monthly mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit.

2. Summary of Comments and Responses on Subpart WW

This section summarizes the major comments and responses related to the proposed subpart WW. The EPA previously requested comment on the addition of coke calciners production source category as a new subpart to part 98 in the 2022 Data Quality Improvements Proposal. The EPA received several comments for subpart WW on the 2022 Data Quality Improvements Proposal; many of these comments were previously addressed in the preamble to the 2023 Supplemental Proposal, wherein the EPA proposed to add new subpart WW for coke calciners (see section IV.B. of the preamble to the 2023 Supplemental Proposal). The EPA received additional comments regarding the proposed subpart WW following the 2023 Supplemental Proposal. See the document ‘‘Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule’’ in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart WW.

Comment: One commenter stated that the description of coke calciners may be overly narrow. The commenter contended that the language ‘‘in the absence of air or oxygen’’ is not necessarily accurate. The commenter stated that air/oxygen is necessary for combustion to occur, and that the high temperatures required for proper calcination are from the combustion of volatiles and carbon in the green coke.

Response: We understand that air is introduced in the coke calciner to burn the volatiles from the coke, but the air is introduced in a limited fashion (limited oxygen) so that the complete combustion of coke in the calciner does not occur. However, we agree with the commenter that the phrase ‘‘in the absence of air or oxygen’’ may be too restrictive and we have deleted this phrase from the proposed source category description at 40 CFR 98.490(a) in the final rule.

Comment: One commenter stated that coke calciners that use refinery fuel gas or natural gas during startup or during hot standby should be allowed to report emissions from these fuel gases using a methodology from subpart C of part 98, separately from the coke calciner emissions. The commenter stated that where coke calcining and fuel gas combustion are occurring simultaneously, the fuel gas emissions should be subtracted from the emissions that are calculated using CEMS and the proposed stack flow methodology to avoid double counting. The commenter added that the requirements for fuel gas or natural gas composition and heat content use in coke calciners should be the same as required in subpart C.

Response: We agree with the commenter and the issues identified by the commenter were addressed in the 2023 Supplemental Proposal. We are finalizing these provisions for treating GHG emissions from auxiliary fuel use as proposed (see 40 CFR 98.493(b)(1)).

CC. Subpart XX—Calcium Carbide Production

We are finalizing the addition of subpart XX (Calcium Carbide Production) to part 98 as proposed. Section III.CC.1. of this preamble discusses the final requirements of subpart XX. The EPA received comments on the proposed subpart XX which are discussed in section III.CC.2. of this preamble. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the addition of subpart XX as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart XX

This section summarizes the final amendments to subpart XX. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart XX can be found in this section and section III.CC.2. of this preamble.

Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Source Category Definition

The EPA is finalizing the source category definition as proposed. We are defining calcium carbide production to include any process that produces calcium carbide. Calcium carbide is an industrial chemical manufactured from lime (CaO) and carbon, usually petroleum coke, by heating the mixture to 2,000 to 2,100 C (3,632 to 3,812 °F) in an electric arc furnace. During the production of calcium carbide, the use of carbon-containing raw materials (petroleum coke) results in emissions of CO_2.

Although we considered accounting for emissions from the production of acetylene at calcium carbide facilities in the 2022 Data Quality Improvements Proposal, we ultimately determined that acetylene is not produced at the one known plant that produces calcium carbide. For this reason, in the 2023 Supplemental Proposal we did not propose, and as such are not taking final action on, inclusion of reporting of CO_2 emissions from the production of acetylene from calcium carbide under subpart XX.

b. Reporting Threshold

In the 2023 Supplemental Proposal, the EPA proposed no threshold for reporting under subpart XX. The current estimate of emissions from the single known calcium carbide production facility in the United States exceeds 25,000 $mtCO_2e$ by a factor of about 1.9. Therefore we are finalizing, as proposed, the calcium carbide source category as an ''all-in'' subpart. For a full discussion of the threshold analysis, please refer to section IV.C. of the preamble to the 2023 Supplemental Proposal.

c. Calculation Methods

In the 2023 Supplemental Proposal, the EPA reviewed the production processes and available emissions estimation methods for calcium carbide production including a default emission factor methodology, a carbon balance methodology (IPCC Tier 3), and direct measurement using CEMS (see section IV.C.5. of the preamble to the 2023 Supplemental Proposal). We subsequently proposed and are finalizing two different methods for quantifying GHG emissions from calcium carbide manufacturing, depending on current emissions monitoring at the facility. If a qualified CEMS is in place, the CEMS must be used. Otherwise, the facility can elect to either install a CEMS or elect to use the carbon mass balance method.

Direct measurement using CEMS. Facilities with an existing CEMS that meet the requirements outlined in subpart C of part 98 (General Stationary Fuel Combustion) are required to use CEMS to estimate combined process and combustion CO_2 emissions. Facilities are required to follow the requirements of subpart C to estimate all CO_2 emissions from the industrial source. Facilities will be required to follow subpart C to estimate emissions of CO_2, CH_4, and N_2O from stationary combustion.

Carbon balance method. For facilities that do not have CEMS that meet the requirements of 40 CFR part 98 subpart C, the alternate monitoring method is the carbon balance method. For any stationary combustion units included at the facility, facilities will be required to follow the existing requirements at 40 CFR part 98, subpart C to estimate emissions of CO_2, CH_4, and N_2O from stationary combustion. Use of facility specific information is consistent with IPCC Tier 3 methods and is the preferred method for estimating emissions for other GHGRP sectors.

d. Monitoring, QA/QC, and Verification requirements

The EPA is finalizing the monitoring, QA/QC, and verification requirements to subpart XX as proposed. We are finalizing two separate monitoring methods: direct measurement and a mass balance emission calculation.

Direct measurement using CEMS. For facilities where process emissions and/or combustion GHG emissions are contained within a stack or vent, facilities can take direct measurement of the GHG concentration in the stack gas and the flow rate of the stack gas using a CEMS. Under the final rule, if facilities use an existing CEMS to meet the monitoring requirements, they are required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions, facilities will be required to follow the requirements of subpart C to estimate emissions.

The CEMS method requires both a continuous CO_2 concentration monitor and a continuous volumetric flow monitor. To qualify as a CEMS, the monitors are required to be installed, operated, and calibrated according to subpart C of part 98 (40 CFR 98.33(a)(4)), which is consistent with CEMS requirements in other GHGRP subparts.

Carbon balance method. For facilities using the carbon mass balance method, we are requiring the facility to determine the annual mass for each material used for the calculations of annual process CO_2 emissions by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

For the carbon content of the materials used to calculate process CO_2 emissions, we are finalizing a requirement that the owner or operator determine the carbon content using material supplier information or collect and analyze at least three representative samples of the material inputs and outputs each year. The final rule will require the carbon content be analyzed at least annually using standard ASTM methods, including their QA/QC procedures. To reduce burden, if a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, the reporter does not have to determine the monthly mass or annual carbon content of that input or output.

e. Procedures for Estimating Missing Data

We are finalizing as proposed the use of substitute data whenever a quality-assured value of a parameter is used to calculate emissions is unavailable, or ''missing.'' If the carbon content analysis of carbon inputs or outputs is missing, the substitute data value will be based on collected and analyzed representative samples for average carbon contents. If the monthly mass of carbon-containing inputs and outputs is missing, the substitute data value will be based on the best available estimate of the mass of the inputs and outputs from all available process data or data used for accounting purposes, such as purchase records. The likelihood for missing process input or output data is low, as businesses closely track their purchase of production inputs. These missing data procedures are the same as those for the ferroalloy production source category, subpart K of part 98, under which the existing U.S. calcium carbide production facility currently reports.

f. Data Reporting Requirements

The EPA is finalizing, as proposed, that each carbon carbide production facility report the annual CO_2 emissions from each calcium carbide production process, as well as any stationary fuel combustion emissions. In addition, we are finalizing requirements for facilities to provide additional information that forms the basis of the emissions estimates, along with supplemental data, so that we can understand and verify the reported emissions. All calcium carbide production facilities will be required to report their annual production and production capacity, total number of calcium carbide production process units, annual consumption of petroleum coke, each end use of any calcium carbide produced and sent off site, and, if the facility produces acetylene, the annual production of acetylene, the quantity of calcium carbide used for acetylene production at the facility, and the end use of the acetylene produced on-site. The EPA is also finalizing reporting the end use of calcium carbide sent off site, as well as acetylene production information for current or future calcium carbide production facilities, to inform future Agency policy under the CAA.

As proposed, we are finalizing requirements that if a facility uses CEMS to measure their CO_2 emissions, they will be required to also report the identification number of each process unit; the EPA is clarifying in the final rule that if a facility uses CEMS, emissions are reported from each CEMS monitoring location. If a CEMS is not used to measure CO_2 emissions, the facility will also report the method used to determine the carbon content of each material for each process unit, how missing data were determined, and the number of months missing data procedures were used.

g. Records That Must Be Retained

The EPA is finalizing as proposed the requirement that facilities maintain records of information used to determine the reported GHG emissions, to allow us to verify that GHG emissions monitoring and calculations were done correctly. If a facility uses a CEMS to measure their CO_2 emissions, they will be required to record the monthly calcium carbide production from each process unit and the number of monthly and annual operating hours for each process unit. If a CEMS is not used, the facility will be required to retain records of monthly production, monthly and annual operating hours, monthly quantities of each material consumed or produced, and carbon content determinations.

As proposed, we are finalizing requirements that the owner or operator maintain records of how measurements are made, including measurements of quantities of materials used or produced and the carbon content of process input and output materials. The procedures for ensuring accuracy of measurement methods, including calibration, must be recorded.

The final rule also requires the retention of a record of the file generated by the verification software specified in 40 CFR 98.5(b) including:

- Carbon content (percent by weight expressed as a decimal fraction) of the reducing agent (petroleum coke), carbon electrode, product produced, and nonproduct outgoing materials; and
- Annual mass (tons) of the reducing agent (petroleum coke), carbon electrode, product produced, and nonproduct outgoing materials.

2. Summary of Comments and Responses on Subpart XX

The EPA previously requested comment on the addition of a calcium carbide source category as a new subpart to part 98 in the 2022 Data Quality Improvements Proposal. The EPA received one comment objecting to the addition of the proposed source category and one comment on the potential calculation methodology. Subsequently, the EPA responded to the comments and proposed to add new subpart XX for calcium carbide (see section IV.C. of the preamble to the 2023 Supplemental Proposal). The EPA received no comments regarding proposed subpart XX following the 2023 Supplemental Proposal. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart XX.

DD. Subpart YY—Caprolactam, Glyoxal, and Glyoxylic Acid Production

We are finalizing the addition of subpart YY (Caprolactam, Glyoxal, and Glyoxylic Acid Production) to part 98 with revisions in some cases. Section III.DD.1. of this preamble discusses the final requirements of subpart YY. Major comments, as applicable, are addressed in section III.DD.2. of this preamble. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the revisions to subpart YY as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart YY

This section summarizes the substantive final amendments to subpart YY. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart YY can be found in this section. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Source Category Definition

In the 2023 Supplemental Proposal, the EPA proposed that the caprolactam, glyoxal, or glyoxylic acid source category, as defined under subpart YY, would include any facility that produces caprolactam, glyoxal, or glyoxylic acid.

Caprolactam is a crystalline solid organic compound with a wide variety of uses, including brush bristles, textile stiffeners, film coatings, synthetic leather, plastics, plasticizers, paint vehicles, cross-linking for polyurethanes, and in the synthesis of lysine. Caprolactam is primarily used in the manufacture of synthetic fibers, especially Nylon 6.

Glyoxal is a solid organic compound with a wide variety of uses, including as a crosslinking agent in various polymers for paper coatings, textile finishes, adhesives, leather tanning, cosmetics, and oil-drilling fluids; as a sulfur scavenger in natural gas sweetening processes; as a biocide in water treatment; to improve moisture resistance in wood treatment; and as a chemical intermediate in the production of pharmaceuticals, dyestuffs, glyoxylic acid, and other chemicals. It is also used as a less toxic substitute for formaldehyde in some applications (*e.g.,* in wood adhesives and embalming fluids).

Glyoxylic acid is a solid organic compound exclusively produced by the oxidation of glyoxal with nitric acid. It is used mainly in the synthesis of vanillin, allantoin, and several antibiotics like amoxicillin, ampicillin, and the fungicide azoxystrobin.

We are finalizing the source category definition to include any facility that produces caprolactam, glyoxal, or glyoxylic acid as proposed. The source category will exclude the production of glyoxal through the LaPorte process (*i.e.,* the gas-phase catalytic oxidation of ethylene glycol with air in the presence of a silver or copper catalyst). As explained in the 2023 Supplemental Proposal, the LaPorte process does not emit N_2O and there are no methods for estimating CO_2 in available literature.

b. Reporting Threshold

In the 2023 Supplemental Proposal, the EPA proposed no threshold for reporting under subpart YY (*i.e.,* that subpart YY would be an ''all-in'' reporting subpart). The EPA noted that the total process emissions from current production of caprolactam, glyoxal, and glyoxylic acid are estimated at 1.2 million $mtCO_2e$, largely from two known caprolactam production facilities; although the known universe of facilities that produce caprolactam, glyoxal, and glyoxylic acid in the United States is four to six total facilities. We proposed that adding caprolactam, glyoxal, and glyoxylic acid production as an ''all-in'' subpart (*i.e.,* regardless of the facility emissions profile) is a conservative approach to gather information from as many facilities that produce caprolactam, glyoxal, and glyoxylic acid as possible, especially if production of glyoxal and glyoxylic acid increase in the near future. The EPA is finalizing these requirements as proposed.

c. Calculation Methods

In the 2023 Supplemental Proposal, the EPA reviewed the production processes and available emissions estimation methods for caprolactam, glyoxal, and glyoxylic acid production and proposed that only N_2O emissions would be estimated from these processes. The EPA also proposed to require the reporting of combustion emissions from facilities that produce caprolactam, glyoxal, and glyoxylic acid, including CO_2, CH_4, and N_2O.

The EPA reviewed two methods from the 2006 IPCC Guidelines,[43] including the Tier 2 and Tier 3 methodologies, for calculating N_2O emissions from the production of caprolactam, glyoxal, and glyoxylic acid, and subsequently proposed the IPCC Tier 2 approach to quantify N_2O process emissions. We are finalizing the N_2O calculation requirements as proposed, with minor revisions. Following the Tier 2 approach established by the IPCC, reporters will apply default N_2O generation factors on a site-specific basis. This requires raw material input to be known in addition to a standard N_2O generation factor, which differs for each of the three chemicals. In addition, Tier 2 requires site-specific knowledge of the use of N_2O control technologies. The volume or mass of each product is measured with a flow meter or weigh scales. The process-related N_2O emissions are estimated by multiplying the generation factor by the production and the destruction efficiency of any N_2O control technology. The EPA is revising the final rule to adjust the N_2O generation factors (proposed in table 1 to subpart YY) for glyoxal and glyoxylic acid production to correctly reflect the conversion of the IPCC default emission factors, which were intended to be converted from metric tons N_2O emitted per metric ton of product produced to kg N_2O per metric ton of product produced using a conversion factor of 1,000 kg per metric ton. The final rule corrects the generation factor for glyoxal from 5,200 to 520 and, for glyoxylic acid, from 1,000 to 100. The EPA is finalizing a minor clarification to equation 1 to 40 CFR 98.513(d)(2) (proposed as equation YY–1) to re-order the defined parameters of the equation to follow their order of appearance in the equation. The EPA is also finalizing an additional equation (equation 3 to 40 CFR 98.513(f)) from the proposed rule, which sums the monthly process emissions estimated by equation 2 to 40 CFR 98.513(e) (proposed as equation YY–2) to an annual value. This additional equation clarifies the methodology for reporting annual emissions and does not require the collection of any additional data.

For any stationary combustion units included at the facility, we proposed that facilities would be required to follow the existing requirements in 40 CFR part 98, subpart C to calculate emissions of CO_2, CH_4 and N_2O from stationary combustion. We are finalizing the combustion calculation requirements as proposed.

d. Monitoring, QA/QC, and Verification Requirements

Monitoring is required to comply with the N_2O calculation methodologies for reporters that produce caprolactam, glyoxal, and glyoxylic acid. In the 2023 Supplemental Proposal, the EPA proposed that reporters that produce caprolactam, glyoxal, and glyoxylic acid are to determine the monthly and annual production quantities of each chemical and to determine the N_2O destruction efficiency of any N_2O abatement technologies in use. The EPA is finalizing as proposed the requirement for reporters to either perform direct measurement of production quantities or to use existing plant procedures to determine production quantities. *E.g.,* the production rate can be determined through sales records or by direct measurement using flow meters or weigh scales.

For determination of the N_2O destruction efficiency, we are finalizing as proposed the requirement that reporters estimate the destruction efficiency for each N_2O abatement technology. The destruction efficiency can be determined by using the manufacturer's specific destruction efficiency or estimating the destruction efficiency through process knowledge. Documentation of how process knowledge was used to estimate the destruction efficiency is required. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided that the results are still relevant to the current vent stream conditions.

For the caprolactam, glyoxal, and glyoxylic acid production subpart, we are requiring reporters to perform all applicable flow meter calibration and accuracy requirements and maintain documentation as specified in 40 CFR 98.3(i).

e. Procedures for Estimating Missing Data

For caprolactam, glyoxal, and glyoxylic acid production, the EPA is finalizing as proposed the requirement that substitute data for each missing production value is the best available estimate based on all available process data or data used for accounting purposes (such as sales records). For the control device destruction efficiency, assuming that the control device operation is generally consistent from year to year, the substitute data value should be the most recent quality assured value.

f. Data Reporting Requirements

The EPA is finalizing, as proposed, that facilities must report annual N_2O emissions (in metric tons) from each production line. In addition, facilities must submit the following data to facilitate understanding of the emissions data and verify the reasonableness of the reported emissions: number of process lines; annual production capacity; annual production; number of operating hours in the calendar year for each process line; abatement technology used and installation dates (if applicable); abatement utilization factor for each process line; number of times in the reporting year that missing data procedures were followed to measure production quantities of caprolactam, glyoxal, or glyoxylic acid (months); and

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[43] IPCC 2006. IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use. Chapter 3, Chemical Industry Emissions. 2006. *www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_3_Ch3_Chemical_Industry.pdf.*

overall percent N_2O reduction for each chemical for all process lines.

g. Records That Must Be Retained

The EPA is finalizing as proposed the requirement that facilities maintain records documenting the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided. We are also requiring, as proposed, that facilities maintain records documenting the estimate of production rate and abatement technology destruction efficiency through accounting procedures and process knowledge, respectively.

Finally, the EPA is also requiring, as proposed, the retention of a record of the file generated by the verification software specified in 40 CFR 98.5(b) including:

- Monthly production quantities of caprolactam from all process lines;
- Monthly production quantities of glyoxal from all process lines; and
- Monthly production quantities of glyoxylic acid from all process lines.

We are revising the final rule to clarify that these monthly production quantities must be supplied in metric tons and for each process line. Additionally, we are adding a requirement that facilities maintain records of the destruction efficiency of the N_2O abatement technology from each process line, consistent with requirements of equation 2 to 40 CFR 98.513(e). Facilities will enter this information into EPA's electronic verification software in order to ensure proper verification of the reported emission values. Following electronic verification, facilities will be required to retain a record of the file generated by the verification software specified in 40 CFR 98.5(b), therefore, no additional burden is anticipated.

2. Summary of Comments and Responses on Subpart YY

The EPA previously requested comment on the addition of a caprolactam, glyoxal, and glyoxylic acid production source category as a new subpart to part 98 in the 2022 Data Quality Improvements Proposal. The EPA received no comments regarding the addition of the proposed source category. Subsequently, the EPA proposed to add new subpart YY for caprolactam, glyoxal, and glyoxylic acid production (see section IV.D. of the preamble to the 2023 Supplemental Proposal). The EPA received no comments regarding proposed subpart YY following the 2023 Supplemental Proposal.

EE. Subpart ZZ—Ceramics Manufacturing

We are finalizing the addition of subpart ZZ of part 98 (Ceramics Manufacturing) with revisions in some cases. Section III.EE.1. of this preamble discusses the final requirements of subpart ZZ. The EPA received a number of comments on the proposed subpart ZZ which are discussed in section III.EE.2. of this preamble. We are also finalizing as proposed related confidentiality determinations for data elements resulting from the addition of subpart ZZ as described in section VI. of this preamble.

1. Summary of Final Amendments to Subpart ZZ

This section summarizes the final amendments to subpart ZZ. Major changes to the final rule as compared to the proposed revisions are identified in this section. The rationale for these and any other changes to 40 CFR part 98, subpart ZZ can be found in section III.EE.2. of this preamble. Additional rationale for these amendments is available in the preamble to the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal.

a. Source Category Definition

In the 2023 Supplemental Proposal, the EPA defined the ceramics manufacturing source category as any facility that uses nonmetallic, inorganic materials, many of which are clay-based, to produce ceramic products such as bricks and roof tiles, wall and floor tiles, table and ornamental ware (household ceramics), sanitary ware, refractory products, vitrified clay pipes, expanded clay products, inorganic bonded abrasives, and technical ceramics (*e.g.,* aerospace, automotive, electronic, or biomedical applications).

The EPA also proposed that the ceramics source category would apply to facilities that annually consume at least 2,000 tons of carbonates or 20,000 tons of clay heated to a temperature sufficient to allow the calcination reaction to occur, and operate a ceramics manufacturing process unit. The proposed definition of ceramics manufacturers as facilities that use at least the minimum quantity of carbonates or clay (2,000 tons/20,000 tons) was considered consistent with subpart U of part 98 (Miscellaneous Uses of Carbonate). This minimum 2,000 tons of carbonate use was added to subpart U in the 2009 Final Rule based on comments received on the April 10, 2009 proposed rule (74 FR 16448), where commenters requested a carbonate use threshold of 2,000 tons in order to exempt small operations and activities which use carbonates in trace quantities. The proposed source category definition for ceramics manufacturing in the 2023 Supplemental Proposal established a minimum production level as a means to exclude and thus reduce the reporting burden for small artisan-level ceramics manufacturing processes. We defined a ceramics manufacturing process unit as a kiln, dryer, or oven used to calcine clay or other carbonate-based materials for the production of a ceramics product.

The EPA is finalizing the definition of the source category with one change. We are revising the minimum production level in the definition from ''at least 2,000 tons of carbonates or 20,000 tons of clay which is heated to a temperature sufficient to allow the calcination reaction to occur'' to ''at least 2,000 tons of carbonates, either as raw materials or as a constituent in clay, which is heated to a temperature sufficient to allow the calcination reaction to occur.'' These final revisions focus the production level on the carbonates contained within the raw material rather than the total tons of clay; the final revisions will provide a more accurate means of assessing applicability. Facilities will be required to estimate their carbonate usage using available records to determine applicability. For example, facilities that use clay as a raw material input could calculate whether they meet the carbonate use threshold by multiplying the amount of clay they consume (and heat to calcination) annually by the weight fraction of carbonates contained in the clay. These final revisions add two harmonizing edits to 40 CFR 98.523(b)(1) and 98.526(c)(2) to clarify that the carbonate-based raw materials include clay.

b. Reporting Threshold

In the 2023 Supplemental Proposal, the EPA proposed that facilities must report under subpart ZZ if they met the definition of the source category and if their estimated combined emissions (including from stationary combustion and all applicable source categories) exceed a 25,000 $mtCO_2e$ threshold. We are finalizing the threshold as proposed. The final definition of ceramics manufacturers as facilities that use at least the minimum quantity of carbonates (2,000 tons, either as raw materials or as a constituent in clay) and the 25,000 $mtCO_2e$ threshold are both expected to ensure that small ceramics manufacturers are excluded. It is estimated that over 25 facilities will meet the definition of a ceramics manufacturer and the threshold of 25,000 $mtCO_2e$ for reporting. For a full discussion of this analysis, section IV.E. of the preamble to the 2023 Supplemental Proposal.

c. Calculation Methods

In the 2023 Supplemental Proposal, the EPA reviewed the production processes and available emissions estimation methods for ceramics manufacturing and proposed that only CO_2 emissions would be estimated from these processes. The EPA also proposed to require the reporting of combustion emissions, including CO_2, CH_4, and N_2O from the ceramics manufacturing unit and other combustion sources on site.

In the 2023 Supplemental Proposal, the EPA reviewed the production processes and available emissions estimation methods for ceramics manufacturing including a basic mass balance methodology that assumed a fixed percentage for carbonates consumed (IPCC Tier 1), a carbon balance methodology (IPCC Tier 3) based on carbon content and the mass of materials input, and direct measurement using CEMS (see section IV.C.5. of the preamble to the 2023 Supplemental Proposal). We are finalizing, as proposed, two different methods for quantifying GHG emissions from ceramics manufacturing, depending on current emissions monitoring at the facility. If a qualified CEMS is in place, the CEMS must be used. Otherwise, the facility can elect to either install a CEMS or elect to use the carbon mass balance method.

Direct measurement using CEMS. Facilities with a CEMS that meet the requirements in subpart C of part 98 (General Stationary Fuel Combustion) will be required to use CEMS to estimate the combined process and combustion CO_2 emissions. The CEMS measures CO_2 concentration and total exhaust gas flow rate for the combined process and combustion source emissions. CO_2 mass emissions will be calculated from these measured values using equation C–6 and, if necessary, equation C–7 in 40 CFR 98.33(a)(4). The combined process and combustion CO_2 emissions will be calculated according to the Tier 4 Calculation Methodology specified in 40 CFR 98.33(a)(4). Facilities will be required to use subpart C to estimate emissions of CO_2, CH_4, and N_2O from stationary combustion.

Carbon balance method. For facilities using carbon mass balance method, the carbon content and the mass of carbonaceous materials input to the process must be determined. The facility must measure the consumption of specific process inputs and the amounts of these materials consumed by end-use/product type. Carbon contents of materials must be determined through the analysis of samples of the material or from information provided by the material suppliers. Additionally, the quantities of materials consumed and produced during production must be measured and recorded. CO_2 emissions are estimated by multiplying the carbon content of each raw material by the corresponding mass, by a carbonate emission factor, and by the decimal fraction of calcination achieved for that raw material. We are finalizing the carbonate emission factors provided in table 1 to subpart ZZ of part 98 as proposed. These factors, pulled from table N–1 to subpart N of part 98, and from Table 2.1 of the 2006 IPCC Guidelines,[44] are based on stoichiometric ratios and represent the weighted average of the emission factors for each particular carbonate. Emission factors provided by the carbonate vendor for other minerals not listed in table 1 to subpart ZZ may also be used.

For any stationary combustion units included at the facility, facilities will be required to follow subpart C to estimate emissions of CO_2, CH_4, and N_2O from stationary combustion. Use of facility specific information under the carbon mass balance method is consistent with IPCC Tier 3 methods and is the preferred method for estimating emissions for other GHGRP sectors.

d. Monitoring, QA/QC, and Verification Requirements

The EPA is finalizing, as proposed, two separate monitoring methods: direct measurement and a mass balance emission calculation.

Direct measurement using CEMS. We are finalizing the CEMS monitoring requirements as proposed. In the case of ceramics manufacturing, process and combustion GHG emissions from ceramics process units are typically emitted from the same stack. If facilities use an existing CEMS to meet the monitoring requirements, they will be required to use CEMS to estimate CO_2 emissions. Where the CEMS capture all combustion- and process-related CO_2 emissions, facilities will be required to follow the requirements of subpart C of part 98 to estimate all CO_2 emissions from the industrial source. The CEMS method requires both a continuous CO_2 concentration monitor and a continuous volumetric flow monitor. To qualify as a CEMS, the monitors will be required to be installed, operated, and calibrated according to subpart C of part 98 (40 CFR 98.33(a)(4)), which is consistent with CEMS requirements in other GHGRP subparts.

Carbon balance method. We are finalizing the carbon mass balance method as proposed, with one change. The carbon mass balance method requires monitoring of mass quantities of carbonate-based raw material (*e.g.,* clay) fed to the process, establishing the mass fraction of carbonate-based minerals in the raw material, and an emission factor based on the type of carbonate consumed. The mass quantities of carbonate-based raw materials consumed by each ceramics process unit can be determined using direct weight measurement of plant instruments or techniques used for accounting purposes, such as calibrated scales, weigh hoppers, or weigh belt feeders. The direct weight measurement can then be compared to records of raw material purchases for the year.

For the carbon content of the materials used to calculate process CO_2 emissions, the final rule requires that the owner or operator determine the carbon mass fraction either by using information provided by the raw material supplier, by collecting and sending representative samples of each carbonate-based material consumed to an off-site laboratory for a chemical analysis of the carbonate content (weight fraction), or by choosing to use the default value of 1.0. The use of 1.0 for the mass fraction assumes that the carbonate-based raw material comprises 100 percent of one carbonate-based mineral. We are revising the final rule to also state that where it is determined that the mass fraction of a carbonate-based raw material is below the detection limit of available testing standards, the facility must assume a default of 0.005 for that material.

We are revising the final rule to allow facilities that determine the carbonate-based mineral mass fractions of a carbonate-based material to use additional sampling and chemical analysis methods to provide additional flexibility for facilities. Specifically, we are revising 40 CFR 98.524(b) from requiring sampling and chemical analysis using consensus standards that specify x-ray fluorescence to requiring that facilities use an ‘‘x-ray fluorescence test, x-ray diffraction test, or other enhanced testing method published by an industry consensus standards

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[44] IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use, Mineral Industry Emissions. 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_2_Ch2_Mineral_Industry.pdf.*

organization'' (*e.g.,* ASTM, American Society of Mechanical Engineers (ASME), American Petroleum Institute (API)). The final rule requires the carbon content be analyzed at least annually to verify the mass fraction data provided by the supplier of the raw material.

For the ceramics manufacturing source category, we are finalizing the QA/QC requirements as proposed. Reporters must calibrate all meters or monitors and maintain documentation of this calibration as documented in subpart A of part 98 (General Provisions). These meters or monitors should be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization, and will be required to be recalibrated either annually or at the minimum frequency specified by the manufacturer. In addition, any flow rate monitors used for direct measurement will be required to comply with QA/QC procedures for daily calibration drift checks and quarterly or annual accuracy assessments, such as those provided in Appendix F to part 60 or similar QA/QC procedures. We are finalizing these requirements to ensure the quality of the reported GHG emissions and to be consistent with the current requirements for CEMS measurements within subparts A (General Provisions) and C of the GHGRP. For measurements of carbonate content, reporters will assess representativeness of the carbonate content received from suppliers with laboratory analysis.

e. Procedures for Estimating Missing Data

We are finalizing the procedures for estimation of missing data as proposed. The final rule requires the use of substitute data whenever a quality-assured value of a parameter that is used to calculate emissions is unavailable, or ''missing.'' For example, if the CEMS malfunctions during unit operation, the substitute data value would be the average of the quality-assured values of the parameter immediately before and immediately after the missing data period. For missing data on the amounts of carbonate-based raw materials consumed, we are finalizing that reporters must use the best available estimate based on all available process data or data used for accounting purposes, such as purchase records. For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials, reporters will assume that the mass fraction of each carbonate-based mineral is 1.0. The use of 1.0 for the mass fraction assumes that the carbonate-based raw material comprises 100 percent of one carbonate-based mineral. Missing data procedures will be applicable for CEMS measurements, mass measurements of raw material, and carbon content measurements.

f. Data Reporting Requirements

The EPA is finalizing the data reporting requirements for subpart ZZ as proposed, with one minor revision. Each ceramics manufacturing facility must report the annual CO_2 process emissions from each ceramics manufacturing process, as well as any stationary fuel combustion emissions. In addition, facilities must report additional information that forms the basis of the emissions estimates so that we can understand and verify the reported emissions. For ceramic manufacturers, the additional information will include: the total number of ceramics process units at the facility and the total number of units operating; annual production of each ceramics product for each process unit and for all ceramics process units combined; the annual production capacity of each ceramics process unit; and the annual quantity of carbonate-based raw material charged to each ceramics process unit and for all ceramics process units combined. The EPA has revised the final rule to clarify at 40 CFR 98.526(c) that facilities that use the carbon balance method must also report the annual quantity of each carbonate-based raw material (including clay) charged to each ceramics process unit. This change is consistent with the requirements the EPA proposed for facilities conducting direct measurement using CEMS, and is not anticipated to substantively impact the burden to reporters as proposed. For ceramic manufacturers with non-CEMS units, the finalized rules will also require reporting of the following information: the method used for the determination for each carbon-based mineral in each raw material; applicable test results used to verify the carbonate based mineral mass fraction for each carbonate-based raw material charged to a ceramics process unit, including the date of test and test methods used; and the number of times in the reporting year that missing data procedures were used.

g. Records That Must Be Retained

The EPA is finalizing the record retention requirements of subpart ZZ as proposed. All facilities are required to maintain monthly records of the ceramics manufacturing rate for each ceramics process unit and the monthly amount of each carbonate-based raw material charged to each ceramics process unit.

For facilities that use the carbon balance procedure, the final rule requires facilities to also maintain monthly records of the carbonate-based mineral mass fraction for each mineral in each carbonate-based raw material. Additionally, facilities that use the carbon balance procedure will be required to maintain (1) records of the supplier-provided mineral mass fractions for all raw materials consumed annually; (2) results of all analyses used to verify the mineral mass fraction for each raw material (including the mass fraction of each sample, the date of test, test methods and method variations, equipment calibration data, and identifying information for the laboratory conducting the test); and (3) annual operating hours for each unit. If facilities use the CEMS procedure, they are required to maintain the CEMS measurement records.

Procedures for ensuring accuracy of measurement methods, including calibration, must be recorded. The final rule requires records of how measurements are made, including measurements of quantities of materials used or produced and the carbon content of minerals in raw materials.

Finally, the final rule requires the retention of a record of the file generated by the verification software specified in 40 CFR 98.5(b) including:

- Annual average decimal mass fraction of each carbonate-based mineral per carbonate-based raw material for each ceramics process unit (percent by weight expressed as a decimal fraction);
- Annual mass of each carbonate-based raw material charged to each ceramics process unit (tons); and
- The decimal fraction of calcination achieved for each carbonate-based raw material for each ceramics process unit (percent by weight expressed as a decimal fraction).

2. Summary of Comments and Responses on Subpart ZZ

This section summarizes the major comments and responses related to the proposed subpart ZZ. The EPA previously requested comment on the addition of ceramics manufacturing sources category as a new subpart to part 98 in the 2022 Data Quality Improvements Proposal. The EPA received some comments for subpart ZZ on the 2022 Data Quality Improvements Proposal; the majority of these comments were previously addressed in the preamble to the 2023 Supplemental Proposal, wherein the EPA proposed to add new subpart ZZ for ceramics manufacturing (see section III.E. of the preamble to the 2023 Supplemental Proposal). The EPA received additional comments regarding the proposed subpart ZZ following the 2023 Supplemental Proposal. See the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to subpart ZZ.

Comments: One commenter objected to the EPA's inclusion of the brick manufacturing industry in proposed subpart ZZ. The commenter asserted that GHG emissions from the brick industry represent only about 0.027 percent of U.S. anthropogenic emissions, stating that any relative improvement in accuracy of emissions would not change the fact that GHG emissions from brick manufacturing are a very small fraction of the national total.

The commenter provided a number of reasons to exclude brick manufacturing from subpart ZZ. First, the commenter contested the EPA's assumption that all ceramics manufacturing use materials with significant carbonate content. The commenter stated that the materials used for the production of brick are low carbonate clay and shale materials that should not be characterized as ''carbonate-based materials,'' and that the various processes used to prepare raw materials and to form and fire brick are such that higher carbonate materials cannot be used. The commenter added that high carbonate materials can result in durability problems of the brick, ranging from cosmetic ''lime pops'' to scenarios where the brick can actually fail in service. The commenter further stated that the majority production of brick in the United States is red bodied brick, and therefore the use of carbonates including limestone are undesirable, due to bleaching of the red color during firing.

The commenter explained that the EPA's proposal assumes a carbonate content of 10–15 percent, whereas tested averages for brick making materials average 0.58 percent. The commenter provided a table of carbonate brick values based on testing from the NBRC (National Brick Research Center at Clemson University). The commenter stated that, as such, the actual brick making carbonate percentages are only about 3.8–5.8 percent (0.58 percent divided by 10 percent and 15 percent, respectively) of the carbonate material percentages in the proposed rule. The commenter estimated that based on this determination, the inclusion of carbonate process emissions would only increase reported emissions from a facility by about 2.10 percent, and few, if any, additional sites not already reporting exceeding the 25,000 mtCO$_2$e reporting threshold would be required to report. The commenter added that even if facilities do not meet the threshold, the added requirements would impose on all sites additional testing and measurement requirements to determine if they exceed the reporting threshold. The commenter stated that the associated costs do not justify the requirements.

The commenter stated that a limited number of brickmaking sites add small amounts of carbonates to some of their products for various reasons. The commenter explained that some manufacturers add barium carbonate to the brick body mix to prevent soluble salts from forming on the final product. In such cases, the commenter noted that barium carbonate is added typically in the range of 0.05 to 0.1 percent. The commenter also stated that sodium carbonate (added in the range of 0.5 percent) is sometimes used to improve the uptake of water during the brick forming process. The commenter asserted that in such cases, if the additional usages of carbonates are significant, they already would be reported under subpart U.

The commenter noted that the EPA's existing methods for estimating GHG emissions from the brick manufacturing industry are good enough to adequately inform the Agency's policy/regulatory decision making and to satisfy the EPA's desire and obligation to maintain an accurate national GHG emissions inventory. The commenter suggested that the EPA could, in lieu of annual reporting, issue a one-time information collection request.

Response: The EPA has considered the information provided by the commenter and is finalizing the addition of the ceramics category to include the brick industry. Consistent with the other source categories of 40 CFR part 98, requiring annual reporting of data for ceramics facilities is preferred to a one-time information collection request. The collection of annual data will help the EPA to understand changes in industry emissions and trends over time. The snapshot of information provided by a one-time information collection request would not provide the type of ongoing information which could inform potential legislation or EPA policy. Collecting annual data also allows us to incorporate accurate time-series emissions changes for the ceramics industry in the GHG Inventory and other EPA analyses. Further, including brick manufacturing in the ceramics source category is consistent with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.[45] While the commenter asserts that brick manufacturing is a small percentage of the total national GHG emissions, the ceramics subpart would cover more industries than just brick manufacturing and is anticipated to cover emissions comparable to other existing subparts. We have included both an emissions threshold and a carbonate use threshold in order to exempt small facilities or those with minor emissions.

Rather than exempting the brick industry from the ceramics subpart entirely, we have taken the commenter's concerns into account and are modifying the definition of the source category such that the subpart ''would apply to facilities that annually consume at least 2,000 tons of carbonates, either as raw materials or as a constituent in clay . . .''. This is in contrast to the original proposed definition which included the phrase ''or 20,000 tons of clay.'' This revised carbonate use threshold will exclude and thus avoid the reporting burden for facilities that use low annual quantities of carbonates, such as brick manufacturers that use low-carbonate clay. Facilities could estimate their carbonate usage to determine their applicability for whether they meet this carbonate use threshold by multiplying the annual amount of clay consumed as a raw material (and heated to calcination) by the weight fraction of carbonates contained in the clay.

Comment: One commenter objected to the proposed measurement protocols of subpart ZZ and indicated that the methods are infeasible for brick manufacturing materials. The commenter stated that the proposal cites ''suitable chemical analysis methods include using an x-ray fluorescence standard method.'' The commenter asserted that the use of x-ray fluorescence requires a minimum of at least 2.0 percent of any single carbonate material to speciate and determine an amount, which is higher than the total of all carbonates in brick making material, which the commenter

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[45] IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use, Mineral Industry Emissions. 2006. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan. *www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/3_Volume3/V3_2_Ch2_Mineral_Industry.pdf.*

provided as 0.58 percent based on testing.

The commenter stated that for brick manufacturing, an alternate measurement of total carbonates such as ASTM E1915 *Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials for Carbon, Sulfur, and Acid-Base Characteristics* (2020)[46] and CO_2e calculation would be a necessary option. The commenter suggested a simpler option would be to develop a default percentage of carbonate in brickmaking raw materials, or an AP–42, Compilation of Air Pollutant Emissions Factors type metric allowing a direct calculation of CO_2e emissions per product throughput tonnage. The commenter contended that this would still yield sufficiently accurate results and suggested that the historical testing data could be the basis for this option.

Response: Upon careful review and consideration, the EPA has considered the information provided by the commenter and will finalize 40 CFR 98.524(b) to allow for other industry standards (*i.e.,* x-ray fluorescence test, x-ray diffraction test, or other enhanced testing method published by an industry consensus standards organization (*e.g.,* ASTM, ASME, API)) as described in 40 CFR 98.524(d) to allow for the flexibility of using the most appropriate standard test method. Furthermore, following consideration of the commenter's recommendation that the EPA include a default carbonate percentage, we are revising 40 CFR 98.524(b) to include a default value of 0.005 for each carbonate material where it is determined that the mass fraction is below the detection limit of available testing standards. The 0.005 value (0.5 percent) is consistent with the example limestone mass fraction that was provided by the Brick Industry Association.[47] Furthermore, the EPA's research into carbonate testing standards revealed that 0.01 (1 percent) is an example detection limit for existing standards (*e.g.,* ASTM F3419–22, *Standard Test Method for Mineral Characterization of Equine Surface Materials by X-Ray Diffraction (XRD) Techniques* (2022)[48]). In scientific settings, it is a common practice to assume that a value of one half the detection limit when concentrations are too low to accurately measure.

Comment: One commenter stated that the proposed rule requirements to report on a unit-by-unit basis instead of facility wide reporting would impose unnecessary burdens on the brick industry. The commenter asserted that most activities (natural gas billing, clay hauling deliveries, material preparation logs, etc.) are done on a per-site basis. The commenter added that there is no benefit to requiring reporting to be done on a per unit basis, and a per site basis should be adequate for determining if emissions exceed the 25,000 metric ton CO_2e reporting threshold.

Response: The EPA routinely collects unit-level capacity data for process equipment in 40 CFR part 98. These unit-level data are essential for quantifying actual GHG emissions from the facility (*e.g.,* the carbon balance method for estimating emissions relies on the actual quantities of carbonate-based raw materials charged to the ceramics process units, not just those delivered to the facility). Furthermore, we use these data to perform statistical analyses as part of our verification process, which allows us to develop ranges of expected emissions by emission source type and successfully identify outliers in the reported data. We disagree that there will be no benefit to reporting on a unit-level basis, as this information will improve the EPA's verification of reported emissions and will provide a more accurate facility-level and national-level emissions profile for the industry.

IV. Final Revisions to 40 CFR Part 9

The EPA is finalizing the proposed amendment to 40 CFR part 9 to include the OMB control number issued under the PRA for the ICR for the GHGRP. The EPA is amending the table in 40 CFR part 9 to list the OMB approval number (OMB No. 2060–0629) under which the ICR for activities in the existing part 98 regulations that were previously approved by OMB have been consolidated. The EPA received no comments on the proposed amendments to 40 CFR part 9 and is finalizing the change as proposed. This codification in the CFR satisfies the display requirements of the PRA and OMB's implementing regulations at 5 CFR part 1320.

V. Effective Date of the Final Amendments

As proposed in the 2023 Supplemental Proposal, the final amendments will become effective on January 1, 2025. As provided under the existing regulations at 40 CFR 98.3(k), the GWP amendments to table A–1 to subpart A will apply to reports submitted by current reporters that are submitted in calendar year 2025 and subsequent years (*i.e.,* starting with reports submitted for RY2024 on or before March 31, 2025). The revisions to GWPs do not affect the data collection, monitoring, or calculation methodologies used by these existing reporters. All other final revisions, which apply to both existing and new reporters, will be implemented for reports prepared for RY2025 and submitted March 31, 2026. Reporters who are newly subject to the rule (facilities that have not previously reported to the GHGRP), either due to final revisions that change what facilities must report under the rule (*e.g.,* newly subject to subparts I or P or subparts WW, XX, YY, or ZZ), or due to the revisions to GWPs in table A–1 to subpart A, will be required to implement all requirements to collect data, including any required monitoring and recordkeeping, on January 1, 2025.

This final rule includes new and revised requirements for numerous provisions under various aspects of GHGRP, including revisions to applicability and updates to reporting, recordkeeping, and monitoring requirements. Further, as explained in section I.B. and this section of this preamble, it amends numerous sections of part 98 for various specific reasons. Therefore, this final rule is a multifaceted rule that addresses many separate things for independent reasons, as detailed in each respective section of this preamble. We intended each portion of this rule to be severable from each other, though we took the approach of including all the parts in one rulemaking rather than promulgating multiple rules to amend each part of the GHGRP. For example, the following portions of this rulemaking are mutually severable from each other, as numbered: (1) revisions to General Provisions, including updates to GWPs in table A–1 to subpart A of part 98 in section III.A.1. of this preamble, (2) revisions to applicability to subparts G (Ammonia Manufacturing), P (Hydrogen Production), and Y (Petroleum Refineries) to address non-merchant hydrogen production in sections III.E., III.I., and III.M.; (3) revisions to applicability to subparts Y and WW (Coke Calciners) to address stand-alone coke calcining operations; (4) revisions to subparts PP (Carbon Dioxide Suppliers) and new subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916) in sections III.V. and III.Z.; (5) revisions to applicability in subparts UU (Injection of Carbon Dioxide) and subpart VV in sections

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[46] Available at *https://www.astm.org/e1915-20.html.* Accessed January 9, 2024.

[47] See Docket ID. No. EPA–HQ–OAR–2019–0424–0332 at *www.regulations.gov.*

[48] Available at *https://www.astm.org/f3419-22.html.* Accessed January 9, 2024.

III.Z. and III.AA., (6) other regulatory amendments discussed in section III. and IV. of this preamble, and (7) confidentiality determinations as discussed in section VI. of this preamble. Each of the regulatory amendments in section III. is severable from all the other regulatory amendments in that section, and each of the confidentiality determinations in section VI. is also severable from all the other determinations in that section. If any of the above portions is set aside by a reviewing court, then we intend the remainder of this action to remain effective, and the remaining portions will be able to function absent any of the identified portions that have been set aside. Moreover, this list is not intended to be exhaustive, and should not be viewed as an intention by the EPA to consider other parts of the rule not explicitly listed here as not severable from other parts of the rule.

VI. Final Confidentiality Determinations

This section provides a summary of the EPA's final confidentiality determinations and emission data designations for new and substantially revised data elements included in these final amendments, certain existing part 98 data elements for which no determination has been previously established, certain existing part 98 data elements for which the EPA is amending or clarifying the existing confidentiality determination, and the EPA's final reporting determinations for inputs to equations included in the final amendments. This section also summarizes the major comments and responses related to the proposed confidentiality determinations, emission data designations, and reporting determinations for these data elements.

The EPA is not taking final action on any requirements for subpart W (Petroleum and Natural Gas Systems) in this final rule, therefore, we are not taking any action on confidentiality determinations or reporting determinations proposed for data elements in subpart W of part 98 in the 2022 Data Quality Improvements Proposal. See section I.C. of this preamble for a discussion of the EPA's actions regarding subpart W. Additionally, we are not taking any final action on proposed subpart B (Energy Consumption) in this final rule; therefore we are not taking any action on confidentiality determinations proposed in the 2023 Supplemental Proposal for subpart B. See section III.B. of this preamble for additional information on subpart B.

For all remaining data elements included in the 2022 Data Quality Improvements Proposal or 2023 Supplemental Proposal, this section identifies any changes to the proposed confidentiality determinations, emissions data designations, or reporting determinations in the final rule.

A. EPA's Approach To Assess Data Elements

In the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal, the EPA proposed to assess data elements for eligibility of confidential treatment using a revised approach, in response to *Food Marketing Institute* v. *Argus Leader Media,* 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*).[49] The EPA proposed that the *Argus Leader* decision did not affect our approach to designating data elements as ''inputs to emission equations'' or our previous approach for designating new and revised reporting requirements as ''emission data.'' We proposed to continue identifying new and revised reporting elements that qualify as ''emission data'' (*i.e.,* data necessary to determine the identity, amount, frequency, or concentration of the emission emitted by the reporting facilities) by evaluating the data for assignment to one of the four data categories designated by the 2011 Final CBI Rule (76 FR 30782, May 26, 2011) to meet the CAA definition of ''emission data'' in 40 CFR 2.301(a)(2)(i) (hereafter referred to as ''emission data categories''). Refer to section II.B. of the July 7, 2010 proposal (75 FR 39094) for descriptions of each of these data categories and the EPA's rationale for designating each data category as ''emission data.'' For data elements designated as ''inputs to emission equations,'' the EPA maintained the two subcategories, data elements entered into e-GGRT's Inputs Verification Tool (IVT) and those directly reported to the EPA. Refer to section VI.C. of the preamble of the 2022 Data Quality Improvements Proposal for further discussion of ''inputs to emission equations.''

In the 2022 Data Quality Improvements Proposal, for new or revised data elements that the EPA did not propose to designate as ''emission data'' or ''inputs to emission equations,'' the EPA proposed a revised approach for assessing data confidentiality. We proposed to assess each individual reporting element according to the new *Argus Leader* standard. So, we evaluated each data element individually to determine whether the information is customarily and actually treated as private by the reporter and proposed a confidentiality determination based on that evaluation.

The EPA received several comments on its proposed approach in the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal. The commenters' concerns and the EPA's responses thereto are provided in the document ''Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule'' in Docket ID. No. EPA–HQ–OAR–2019–0424. Following consideration of the comments received, the EPA is not revising this approach and is continuing to assess data elements for confidentiality determinations as described in the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal. We are also finalizing the specific confidentiality determinations and reporting determinations as described in section VI.B. and VI.C. of this preamble.

B. Final Confidentiality Determinations and Emissions Data Designations

1. Summary of Final Confidentiality Determinations

a. Final Confidentiality Determinations for New and Revised Data Elements

The EPA is making final confidentiality determinations and emission data designations for new and substantially revised data elements included in these final amendments. Substantially revised data elements include those data elements where the EPA is, in this final action, substantially revising the data elements as compared to the existing requirements. Please refer to the preamble to the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal for additional information regarding the proposed confidentiality determinations for these data elements.

For subparts A (General Provisions), C (General Stationary Fuel Combustion), F (Aluminum Production), G (Ammonia Manufacturing), H (Cement Production), P (Hydrogen Production), S (Lime Manufacturing), HH (Municipal Solid Waste Landfills), OO (Suppliers of Industrial Greenhouse Gases), and QQ (Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams), the EPA is not finalizing the proposed confidentiality determinations for certain data elements because the

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[49] Available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2019–0424).

EPA is not taking final action on the requirements to report these data elements at this time (see section III. of this preamble for additional information). These data elements are listed in table 5 of the memorandum ''Confidentiality Determinations and Emission Data Designations for Data Elements in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule,'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

For subparts C (General Stationary Fuel Combustion) and PP (Suppliers of Carbon Dioxide), the EPA has revised its final confidentiality determinations or emissions data designations for certain data elements from proposal. For subpart PP, following consideration of public comments, the EPA has revised its final confidentiality determination for eight data elements that were proposed as ''Not Eligible'' to ''Eligible for Confidential Treatment.'' See section VI.B.2. of this preamble for a summary of the related comments and the EPA's response. For subpart C, we identified two revised data elements where the EPA had inadvertently proposed to place the revised version of the data elements into a different emissions data category than the existing version of the data elements (*i.e.,* proposed moving the data elements from one category of emissions data into a different category of emissions data). The EPA has corrected the placement of these data elements from ''Facility and Unit Identifier Information'' to ''Emissions.'' Table 6 of this preamble lists the data elements where the EPA has revised its final confidentiality determinations or emissions data designations as compared to the 2022 Data Quality Improvements Proposal.

TABLE 6—DATA ELEMENTS FOR WHICH THE EPA IS REVISING THE FINAL CONFIDENTIALITY DETERMINATIONS OR EMISSION DATA DESIGNATIONS

Subpart	Citation in 40 CFR part 98	Data element description
C[1]	98.36(c)(1)(vi)	When reporting using aggregation of units, if any of the stationary fuel combustion units burn biomass, the annual CO_2 emissions from combustion of all biomass fuels combined (metric tons).
C[1]	98.36(c)(3)(vi)	When reporting using the common pipe configuration, if any of the stationary fuel combustion units burn biomass, the annual CO_2 emissions from combustion of all biomass fuels combined (metric tons).
PP[2]	98.426(i)(1)	If you capture a CO_2 stream at a facility with a direct air capture (DAC) process unit and electricity (excluding combined heat and power (CHP)) is provided to a dedicated meter for the DAC process unit: annual quantity of electricity (generated on-site or off-site) consumed for the DAC process unit (MWh).
PP[2]	98.426(i)(1)(i)(C)	If you capture a CO_2 stream at a facility with a DAC process unit and electricity (excluding CHP) is provided to a dedicated meter for the DAC process unit: if the electricity is sourced from a grid connection, the name of the electric utility company that supplied the electricity as shown on the last monthly bill issued by the utility company during the reporting period.
PP[2]	98.426(i)(1)(i)(D)	If you capture a CO_2 stream at a facility with a DAC process unit and electricity (excluding CHP) is provided to a dedicated meter for the DAC process unit: if the electricity is sourced from a grid connection, the name of the electric utility company that delivered the electricity.
PP[2]	98.426(i)(1)(i)(E)	If you capture a CO_2 stream at a facility with a DAC process unit and electricity (excluding CHP) is provided to a dedicated meter for the DAC process unit: if the electricity is sourced from a grid connection, the annual quantity of electricity consumed for the DAC process unit (MWh).
PP[2]	98.426(i)(1)(ii)	If you capture a CO_2 stream at a facility with a DAC process unit and electricity (excluding CHP) is provided to a dedicated meter for the DAC process unit: if electricity is sourced from on-site or through a contractual mechanism for dedicated off-site generation, the annual quantity of electricity consumed per applicable source (MWh), if known.
PP[2]	98.426(i)(2)	If you capture a CO_2 stream at a facility with a DAC process unit and you use heat, steam, or other forms of thermal energy (excluding CHP) for the DAC process unit: the annual quantity of heat, steam, or other forms of thermal energy sourced from on-site or through a contractual mechanism for dedicated off-site generation per applicable energy source (MJ), if known.
PP[2]	98.426(i)(3)(i)	If you capture a CO_2 stream at a facility with a DAC process unit and electricity from CHP is sourced from on-site or through a contractual mechanism for dedicated off-site generation: the annual quantity of electricity consumed for the DAC process unit per applicable energy source (MWh), if known.
PP[2]	98.426(i)(3)(ii)	If you capture a CO_2 stream at a facility with a DAC process unit and you use heat from CHP for the DAC process unit: the annual quantity of heat, steam, or other forms of thermal energy from CHP sourced from on-site or through a contractual mechanism for dedicated off-site generation per applicable energy source (MJ), if known.

[1] In the May 26, 2011, final rule (76 FR 30782), this data element was assigned to the ''Emissions Data'' data category and determined to be ''Emissions Data.'' In the 2022 Data Quality Improvements Proposal, the data element was significantly revised, and the EPA proposed that the revised data element would be assigned to the data category ''Facility and Unit Identifier'' and would have a determination of ''Emissions Data.'' We have subsequently determined that the revisions to the data element (revising the language ''if any units burn both fossil fuels and biomass'' with ''if any of the units burn biomass'') is a clarifying change and that the data element was incorrectly assigned to a new data category. Therefore we are finalizing the revised data element in the ''Emissions Data'' data category and determining that it is ''Emissions Data.''

[2] Revised from ''Not Eligible'' to ''Eligible for Confidential Treatment''; see section VI.B.2. of this preamble.

For subparts I (Electronics Manufacturing), P (Hydrogen Production), and ZZ (Ceramics Manufacturing), the EPA is finalizing revisions that include new data elements for which the EPA did not propose a determination. These data elements are listed in table 7 of this preamble and table 6 of the memorandum, ''Confidentiality Determinations and Emission Data Designations for Data Elements in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule,'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424. Because the EPA has not proposed or solicited public comment on a determination for these data elements, we are not finalizing confidentiality determinations for these data elements at this time.

TABLE 7—NEW DATA ELEMENTS FROM PROPOSAL TO FINAL FOR WHICH THE EPA IS NOT FINALIZING CONFIDENTIALITY DETERMINATIONS OR EMISSION DATA DESIGNATIONS

Subpart	Citation in 40 CFR part 98	Data element description
I	98.96(y)(2)(iv)	For electronics manufacturing facilities, for the technology assessment report required under 40 CFR 98.96(y), for any destruction or removal efficiency data submitted, if you choose to use an additional alternative calculation methodology to calculate and report the input gas emission factors and by-product formation rates: a complete, mathematical description of the alternative method used (including the equation used to calculate each reported utilization and by-product formation rate).
P	98.166(d)(10)	For each hydrogen production process unit, an indication (yes or no) if best available monitoring methods used in accordance with 40 CFR 98.164(c) to determine fuel flow for each stationary combustion unit directly associated with hydrogen production (*e.g.,* reforming furnace and hydrogen production process unit heater).
P	98.166(d)(10)(i)	For each hydrogen production process unit, if best available monitoring methods were used in accordance with 40 CFR 98.164(c) to determine fuel flow for each stationary combustion unit directly associated with hydrogen production, the beginning date of using best available monitoring methods.
P	98.166(d)(10)(ii)	For each hydrogen production process unit, if best available monitoring methods were used in accordance with 40 CFR 98.164(c) to determine fuel flow for each stationary combustion unit directly associated with hydrogen production, the anticipated or actual end date of using best available monitoring methods.
ZZ	98.526(c)(2)	For a facility containing a ceramics manufacturing process, for each ceramics manufacturing process unit, if process CO_2 emissions are calculated according to the procedures specified in 40 CFR 98.523(b), annual quantity of each carbonate-based raw material (including clay) charged (tons) (no CEMS).

In a handful of cases, the EPA has made minor revisions to data elements in this final action as compared to the proposed data element included in either the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal. For certain proposed data elements, we have revised the citations from proposal to final. In other cases, the minor revisions include clarifications to the text. The EPA evaluated these data elements and how they have been clarified in the final rule to verify that the information collected has not substantially changed since proposal. These data elements are listed in table 7 of the memorandum ''Confidentiality Determinations and Emission Data Designations for Data Elements in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule,'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424. Because the information to be collected has not substantially changed since proposal, we are finalizing the confidentiality determinations or emission data designations for these data elements as proposed. For additional information on the rationales for the confidentiality determinations for these data elements, see the preamble to the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal and the memoranda ''Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule'' and ''Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Supplemental Revisions to the Greenhouse Gas Reporting Rule,'' available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2019–0424).

For all other confidentiality determinations for the new or substantially revised data reporting elements for these subparts, the EPA is finalizing the confidentiality determinations as they were proposed. Please refer to the preamble to the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal for additional information regarding these confidentiality determinations.

b. Final Confidentiality Determinations and Emission Data Designations for Existing Data Elements for Which EPA Did Not Previously Finalize a Confidentiality Determination or Emission Data Designation

The EPA is finalizing all confidentiality determinations as they were proposed for other part 98 data reporting elements for which no determination has been previously established. The EPA received no comments on the proposed determinations. Please refer to the preamble to the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal for additional information regarding the proposed confidentiality determinations.

c. Final Confidentiality Determinations for Existing Data Elements for Which the EPA is Amending or Clarifying the Existing Confidentiality Determination

The EPA is finalizing as proposed all confidentiality determinations for other part 98 data reporting elements for which the EPA proposed to amend or clarify the existing confidentiality determinations. The EPA received no comments on the proposed determinations. Please refer to the preamble to the 2022 Data Quality Improvements Proposal for additional information regarding the proposed confidentiality determinations.

2. Summary and Response to Public Comments on Proposed Confidentiality Determinations

The EPA received several comments related to the proposed confidentiality determinations. The EPA received minimal comments on the proposed confidentiality determinations for all new or substantially revised data elements, except certain data elements in subparts PP (Suppliers of Carbon Dioxide) and VV (Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916) as described in this section. Additional comments may be found in the EPA's comment response document in Docket ID. No. EPA–HQ–OAR–2019–

0424. For subparts PP and VV, we received comments questioning the proposed confidentiality determination of certain new and substantially revised data elements in each subpart, including requests that the data elements be treated as confidential. Summaries of the major comments and the EPA's responses thereto are provided below. Additional comments and the EPA's responses may be found in the comment response document noted above.

Comment: One commenter contended that public disclosure of the annual quantity of electricity consumed to power the DAC process unit and natural gas used for thermal energy could undermine the commercial deployment of DAC. The commenter stated that this information should be kept as confidential. The commenter explained that power in a DAC facility is one of the main operating expenses and power consumption is directly related to power cost. The commenter stated that a comprehensive understanding of a DAC unit's power demand, coupled with a basic understanding of the clean power markets in the region where the DAC facility is located, could be used to estimate the DAC power cost. The commenter contended that this knowledge, if available to a competitor or provider of clean power, would affect business-to-business contract negotiations, allow for speculation on potential profit margins on captured CO_2 volumes, and negatively impact the ability of a DAC operator to procure clean power at competitive rates.

The commenter added that many carbon capture technologies will utilize natural gas to provide the thermal energy needed to drive the CO_2 capture process, including DAC facilities. The commenter explained contract negotiations for the supply of natural gas for DAC facilities are competitive and a major operating cost for a DAC facility and information on the annual amount of natural gas consumed by a DAC facility, if available to a competitor or natural gas supplier, will affect the ability of a DAC operator to contract for responsibly sourced natural gas supply at a competitive cost. The commenter requested that natural gas consumption be declared CBI. The commenter added that they still supported the requirement to report on whether flue gas is also captured by the DAC process unit as this requirement allows for a clear distinction of CO_2 captured from the process versus CO_2 captured from the air, increasing public trust in reported CO_2 volumes.

Response: The EPA proposed that 12 new subpart PP data elements in 40 CFR 98.426(i) specific to DAC facilities would not be eligible for confidential treatment. These data elements included: the annual quantities of on-site and off-site electricity consumed for the DAC process unit; the annual quantities of heat, steam, other forms of thermal energy, and combined heat and power (CHP) consumed by the DAC process unit; the state and county where the facility with the DAC process unit is located; the name of the electric utility company that supplied and delivered the electricity if electricity is sourced from a grid connection; the annual quantity of electricity consumed by the DAC process unit supported by billing statements; the annual quantity of electricity, heat, and CHP consumed for the DAC process unit by each applicable source; and whether flue gas is also captured by the DAC process unit when electricity or CHP is generated on-site from natural gas, coal, or oil.

The EPA's proposed determinations were based on research that indicated the proposed data elements are not customarily and actually treated as private by the reporter. We note that this, rather than competitive harm, is now the standard for treating reported data elements as ''Eligible for Confidential Treatment'' or ''Not Eligible'' based on the decision in *Food Marketing Institute* v. *Argus Leader Media,* 139 S. Ct. 2356 (2019). While the commenter explains that there may be competitive harm from releasing electricity and natural gas consumption data in 40 CFR 98.426, they do not clearly demonstrate whether such data are customarily and actually treated as confidential. Following receipt of public comment, the EPA conducted additional research on the public availability of energy use data for DAC and other facilities, and determined that, with the exception of the state and county where the DAC facility is located, the other proposed data elements are not consistently available to the public at this time. As DAC is a nascent field, there are not yet many examples of such facilities to support a determination as to whether the other proposed data elements are typically and actually held confidential. The EPA, therefore, partially agrees with the commenter that certain data elements for DAC process unit energy requirements in 40 CFR 98.426(i) may be treated as confidential by certain facilities. The EPA is, therefore, making a determination of ''Eligible for Confidential Treatment'' for certain data elements. Specifically, the EPA is finalizing the rule with all new data elements in 40 CFR 98.426(i) having the categorical determination of ''Eligible for Confidential Treatment'' except for proposed 40 CFR 98.426(i)(1)(i)(A) and (B), the state and county where the DAC process unit is located, and certain information reported under 40 CFR 98.426(i)(1) through (3), which requires the reporter to indicate each applicable energy source type (*e.g.,* natural gas, oil, coal, nuclear) and provide an indication of whether flue gas is captured (proposed 40 CFR 98.426(i)(1)), respectively. The rule is being finalized with the determination that these four data elements are not eligible for confidential treatment. The requirements to report the state and county are similar to data required to be reported under 40 CFR 98.3(c)(1) that was designated as ''emission data,'' which under CAA section 114 is not entitled to confidential treatment (76 FR 30782, May 26, 2011; CBI Memo, April 29, 2011). Furthermore, the EPA has previously determined that indication of source is not confidential (77 FR 48072, August 13, 2012). Regarding reporting whether flue gas is captured, the EPA has previously determined that an indication of flue gas is ''Not Eligible'' (76 FR 30782, May 26, 2011). While the source of energy would be ''Not Eligible'' for confidential treatment, the actual quantities of energy reported under 40 CFR 98.426(i)(1) through (3) would be ''Eligible for Confidential Treatment.'' The EPA will consider revising the confidentiality status of the energy consumption data elements in the future, as more DAC facilities begin operating and we have a better understanding of how these data are customarily treated. For example, if DAC facilities begin customarily sharing their energy consumption information to advertise their energy efficiency, we may consider revising the confidentiality status to ''No Determination'' or ''Not Eligible for Confidential treatment.''

Comment: The EPA received several comments regarding the confidential treatment of the proposed EOR OMP at 40 CFR 98.488. Several commenters strongly supported the publishing of non-confidential data related to anthropogenic CO_2 volumes permanently stored in in CO_2–EOR operations, including the EOR OMP. Commenters compared the EOR OMP to the MRV plan issued or required under subpart RR, noting that the plans serve very similar purposes and include a geologic characterization of the storage location, information about wells within the storage site area, operations history, monitoring programs, and calculation and quantification methods used to determine the total amount of CO_2

stored in the storage site. One commenter strongly objected to the public disclosure of the OMP. The commenter stated that, unlike an MRV which must receive approval by the EPA under subpart RR, there is no such approval required for an OMP under subpart VV, which is appropriate given the differences in the subpart methodologies. The commenter added that reporting entities are currently free to exercise discretion to publicly disclose their OMPs.

Response: The EPA disagrees with the commenter. The EPA's review and approval of a document does not determine whether the document is eligible for confidential treatment. The EPA proposed that the OMP is not eligible for confidential treatment because it does not consider the data elements in the OMP to be customarily and actually treated as confidential. We note that this, rather than whether the EPA reviews and approves a submission, is the standard for confidentiality of reported data elements based on the *Argus Leader* decision. For example, the OMP shall include geologic characterization of the EOR complex, a description of the facilities within the CO_2–EOR project, a description of all wells and other engineered features in the CO_2–EOR project, the operations history of the project reservoir, descriptions of containment assurance and the monitoring plan, mass of CO_2 previously injected and other information required in the CSA/ANSI ISO 27916:19 standard. This information is normally available to the public through geologic records, construction and operating permitting files, well permits, tax records, and other public records. Furthermore, such information is available in EPA-approved subpart RR MRV plans which have been determined to be not-confidential and are consistently made publicly available on the EPA's website. That the EPA does not have a role in approving the OMP does not mean that the content itself is typically and actually held confidential.

C. Final Reporting Determinations for Inputs to Emission Equations

In the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal, the EPA proposed to assign several data elements to the ''Inputs to Emission Equation'' data category. As discussed in section VI.B.1. of the preamble to the 2022 Data Quality Improvements Proposal, the EPA determined that the *Argus Leader* decision does not affect our approach for handling of data elements assigned to the ''Inputs to Emission Equations'' data category. Data assigned to the ''Inputs to Emission Equations'' data category are assigned to one of two subcategories, including ''inputs to emission equations'' that must be directly reported to the EPA, and ''inputs to emission equations'' that are not reported but are entered into the EPA's Inputs Verification Tool (IVT). The EPA received no comments specific to the proposed reporting determinations for inputs to emission equations in the proposed rules. Additional information regarding these reporting determinations may be found in section VI.C. of the preamble to the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal.

The EPA is finalizing the reporting determinations for data elements that the EPA proposed to assign to the ''Inputs to the Emission Equation'' data category as they were proposed for all subparts with the exception of certain records proposed for subparts G (Ammonia Production), P (Hydrogen Production), S (Lime Production), and HH (Municipal Solid Waste Landfills). For subparts G, P, and S, the new and substantially revised data elements were not proposed to be included in the reporting section of those subparts but were instead to be retained as records to be input into the EPA's IVT, and the EPA did not evaluate these data elements further. The EPA is not taking final action on these inputs into IVT because the EPA is not taking final action on the requirement to retain these data elements as records (see section III. of this preamble for additional information.) For subpart HH, the EPA is not finalizing the proposed reporting determinations for certain data elements because the EPA is not taking final action on the requirements to report these data elements at this time (see section III. of this preamble for additional information). These data elements are listed in table 3 of the memorandum ''Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule,'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424.

In a handful of cases, the EPA has made minor revisions to data elements assigned to the ''Inputs to Emissions Equations'' data category in this final action as compared to the proposed data element included in the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal. For certain proposed data elements, we have revised the citations from proposal to final. In other cases, the minor revisions include clarifications to the text. The EPA evaluated these inputs to emissions equations and how they have been clarified in the final rule to verify that the data element has not substantially changed since proposal. These data elements and how they have been clarified in the final rule are listed in table 4 of the memorandum ''Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule,'' available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2019–0424. Because the input has not substantially changed since proposal, we are finalizing the proposed reporting determinations for these data elements as proposed. For additional information on the rationale for the reporting determinations for the data elements, see the preamble to the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal and the memorandums ''Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Revisions to the Greenhouse Gas Reporting Rule'' and ''Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Supplemental Revisions to the Greenhouse Gas Reporting Rule,'' available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2019–0424).

For all other reporting determinations for the data elements assigned to the ''Inputs to Emission Equations'' data category, the EPA is finalizing the reporting determinations as they were proposed. Please refer to the preamble to the 2022 Data Quality Improvements Proposal or the 2023 Supplemental Proposal for additional information.

VII. Impacts and Benefits of the Final Amendments

This section of the preamble examines the costs and economic impacts of the final rule and the estimated impacts of the rule on affected entities, in addition to the benefits of the final rule. The revisions in this final rule are anticipated to increase burden in cases where the amendments expand the applicability, monitoring, or reporting requirements of part 98. In some cases, the final amendments are anticipated to decrease burden where we streamlined the rule to remove notification or reporting requirements or simplify monitoring and reporting requirements. The final rule consolidates amendments from the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal that revise 32 subparts that directly affect 30 industries—including revisions to update the GWPs in table A–1 to subpart A of part 98 that affect the number of facilities required to report under part 98; revisions to implement five new source categories or to expand existing source categories that may require facilities to newly report or to report under new provisions; and revisions to add new reporting requirements to a number of subparts that will improve the quality of the data collected under part 98. The bulk of costs associated with the final rule includes those costs to facilities that would be required to newly report under part 98 (subparts I, P, W, DD, HH, II, OO, TT, WW, XX, YY, and ZZ). However, the majority of subparts affected will reflect a modest increase in burden to individual reporters. As discussed in the preamble to the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal, in several cases the final rule amendments are anticipated to result in a decrease in burden. In some cases we have quantified where the final rule would result in a decrease in burden for certain reporters, but in other cases we were unable to quantify this decrease. The final revisions also include minor amendments, corrections, and clarifications, including simple revisions of requirements such as clarifying changes to definitions, calculation methodologies, monitoring and quality assurance requirements, and reporting requirements. These revisions clarify part 98 to better reflect the EPA's intent, and do not present any additional burden on reporters. The impacts of the final rule generally reflect an increase in burden for most subparts.

The EPA received a number of comments on the proposed revisions and the impacts of the proposed revisions in both the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal. See the document ‘‘Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule’’ in Docket ID. No. EPA–HQ–OAR–2019–0424 for a complete listing of all comments and responses related to the impacts of the proposed rules. Following consideration of these comments, the EPA has, in some cases, revised the final rule requirements and updated the impacts analysis to reflect these changes.

As noted in section I.C. of this preamble, although the EPA proposed amendments to subpart W (Petroleum and Natural Gas Systems) in the 2022 Data Quality Improvements Proposal, this final rule does not address implementation of these revisions to subpart W, which the EPA is reviewing in concurrent rulemakings. Additionally, as stated in section III.B. of this preamble, the EPA is not taking final action on its proposed amendments to add a source category for collection of data on energy consumption (subpart B) at this time. Accordingly, the impacts of the final rule do not reflect the costs for these proposed revisions.

For some subparts, we are not taking final action on revisions to calculation, monitoring, or reporting requirements that would have required reporters to collect or submit additional data. For example, for subpart C (General Stationary Fuel Combustion), we are not taking final action on proposed revisions to (1) add new reporting for the unit type, maximum rated heat input capacity, and an estimate of the fraction of the total annual heat input from each unit in either an aggregation of units or common pipe configuration (excluding units less than 10 mmBtu/hour); and (2) add new reporting to identify whether any unit in the configuration (individual units, aggregation of units, common stack, or common pipe) is an EGU, and, for multi-unit configurations, an estimated decimal fraction of total emissions from the group that are attributable to EGU(s) included in the group. For subparts G (Ammonia Production), P (Hydrogen Production), S (Lime Production), and HH (Municipal Solid Waste Landfills) we are not taking final action on certain revisions to the calculation methodologies that would have revised how data is collected and reported in e-GGRT. Similarly, we are not taking final action on certain data elements that were proposed to be added to subparts A (General Provisions), F (Aluminum Production), G (Ammonia Production), H (Cement Production), P, S (Lime Production), HH, OO (Suppliers of Industrial Greenhouse Gases), and QQ (Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment and Closed-Cell Foams). Therefore, the final burden for these subparts has been revised to reflect only those requirements that are being finalized, and is lower than proposed.

In a few cases, the EPA has adjusted the burden of the final rule to account for additional costs associated with the final rule. In these cases, we have made minor adjustments to the reporting and recordkeeping requirements in the final rule. Specifically, we are finalizing changes from the proposed rule that would add 8 new data elements to subparts I, P, DD, and ZZ (see section III. of this preamble for additional information). The final rule burden estimate has been adjusted to include additional time and labor for these activities, which the EPA estimates is minimal for the reasons described in section III. of this preamble. Finally, the burden for the activities in the final rule has been adjusted to reflect updates to the estimated number of affected reporters based on a review of data from RY2022 reporting.

As discussed in section V. of this preamble, the final rule will be implemented on January 1, 2025, and will apply to RY2025 reports. Costs have been estimated over the three years following the year of implementation. One-time implementation costs are incorporated into first year costs, while subsequent year costs represent the annual burden that will be incurred in total by all affected reporters. The incremental implementation labor costs for all subparts include $2,684,681 in RY2025, and $2,671,831 in each subsequent year (RY2026 and RY2027). The incremental implementation labor costs over the next three years (RY2025 through RY2027) total $8,028,343. There is an additional incremental burden of $2,733,937 for capital and O&M costs in RY2025 and in each subsequent year (RY2026 and RY2027), which reflects changes to applicability and monitoring for subparts I, P, W, V, Y, DD, HH, II, OO, TT, UU and new subparts VV, WW, XX, YY, and ZZ. The incremental non-labor costs for RY2025 through RY2027 total $8,201,812 over the next three years. The incremental burden is summarized by subpart for the rule changes that are finalized for initial and subsequent years in table 8 of this preamble. Note that subparts A, U, FF, and RR only include revisions that are clarifications or harmonizing changes that would not result in any changes to burden, and are not included in table 8 of this preamble.

TABLE 8—ANNUAL INCREMENTAL BURDEN OF THE FINAL RULE, BY SUBPART

Subpart	Number of affected facilities	Labor costs		Capital and O&M
		Initial year	Subsequent years	
C—General Stationary Fuel Combustion Sources [a]				
Facilities Reporting only to Subpart C	133	($1,446)	($1,446)	
Facilities Reporting to Subpart C plus another subpart	177	(979)	(979)	
G—Ammonia Manufacturing	29	119	119	
H—Cement Production	94	1,999	1,999	
I—Electronics Manufacturing [b,c]	48	19,651	18,023	$62
N—Glass Production	101	2,074	2,074	
P—Hydrogen Production [b]	114	7,497	7,497	2,561
Q—Iron and Steel Production	121	1,485	1,485	
S—Lime Manufacturing	71	1,186	1,186	
V—Nitric Acid Production [d,e]	1	(2,680)	(2,680)	(11,085)
W—Petroleum and Natural Gas Systems [d]	188	2,433,058	2,433,058	2,717,864
X—Petrochemical Production	31	618	618	
Y—Petroleum Refineries [f]	57	(6,133)	(6,133)	(3,930)
AA—Pulp and Paper Manufacturing	1	104	104	
BB—Silicon Carbide Production	1	20	20	
DD—Electrical Transmission [b]	95	15,278	15,278	3,119
GG—Zinc Production	5	20	20	
HH—Municipal Solid Waste Landfills [b]	1,129	84,651	81,793	374
II—Industrial Wastewater Treatment [d]	2	5,288	4,713	3,077
OO—Suppliers of Industrial Greenhouse Gases [a]	121	6,884	6,884	62
PP—Suppliers of Carbon Dioxide	22	872	872	
QQ—Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams	33	249	249	
SS—Electrical Equipment Manufacture or Refurbishment	5	358	358	
TT—Industrial Waste Landfills [b,d]	1	4,853	3,934	62
UU—Injection of Carbon Dioxide [g]	2	(1,886)	(1,886)	(125)
VV—Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916 [g]	2	1,882	3,443	250
WW—Coke Calciners	15	37,847	34,525	19,649
XX—Calcium Carbide Production	1	2,849	2,627	62
YY—Caprolactam, Glyoxal, and Glyoxylic Acid Production	6	12,285	11,089	374
ZZ—Ceramics Manufacturing	25	56,678	52,987	1,559
Total		2,684,681	2,671,831	2,733,937

[a] Reflects reduced burden due to revisions to simplify calculation methods and remove reporting requirements.

[b] Applies to reporters that may currently report under existing subparts of part 98 and that are newly subject to reporting under part 98.

[c] Average subsequent year costs for subpart I. Subpart I subsequent year costs include $17,794 in Year 2 and $18,252 in Year 3.

[d] Reflects burden to reporters estimated to be affected due to revisions to table A–1 to subpart A only.

[e] Reflects changes to the number of reporters able to off-ramp from reporting under the part 98 source category.

[f] Reflects changes to the number of reporters with coke calciners reporting under subpart Y that would be required to report under proposed subpart WW.

[g] Reflects changes to the number of reporters reporting under subpart UU who will begin submitting reports under new subpart VV in each year.

Additional details on the EPA's review of the impacts may be found in the memorandum, ''Assessment of Burden Impacts for Final Revisions to the Greenhouse Gas Reporting Rule,'' available in Docket ID. No. EPA–HQ–OAR–2019–0424.

The implementation of the final rule will provide numerous benefits for stakeholders, the Agency, industry, and the general public. The final revisions include improvements to the calculation, monitoring, and reporting requirements, incorporate new data and reflect updated scientific knowledge; provide coverage of new emissions sources and additional sectors; improve analysis and verification of collected data; provide additional data to complement or inform other EPA programs; and streamline calculation, monitoring, or reporting to provide flexibility or increase the efficiency of data collection. The revisions will maintain the quality of the data collected under part 98 where continued collection of information assists in evaluation and support of EPA programs and policies under provisions of the CAA. In some cases, the amendments improve the EPA's ability to assess compliance by revising or adding recordkeeping or reporting elements that will allow the EPA to more thoroughly verify GHG data and advance the ability of the GHGRP to provide access to quality data on greenhouse gas emissions by adding or updating emission factors, revising or adding calculation methodologies, or adding key data elements to improve the usefulness of the data.

Because part 98 is a reporting rule, the EPA did not quantify estimated emission reductions or monetize the benefits from such reductions that could be associated with the final rule. The benefits of the final rule are based on its relevance to policy making, transparency, and market efficiency. The improvements to the GHGRP will benefit the EPA, other policymakers, and the public by increasing the completeness and accuracy of facility emissions data. Public data on emissions allows for accountability of emitters to the public. Improved facility-specific emissions data will aid local, state, and national policymakers as they evaluate and consider future climate change policy decisions and other policy decisions for criteria pollutants, ambient air quality standards, and toxic air emissions. For example, GHGRP data on petroleum and natural gas systems (subpart W of part 98) were previously analyzed to inform targeted improvements to the 2016 NSPS for the oil and gas industry and to update emission factor and activity data used for that proposal and the final NSPS, as updated in the Inventory (83 FR 52056; October 15, 2018). Similarly, GHGRP data on municipal solid waste landfills (subpart HH of part 98) were previously used to inform the development of the 2016 NSPS and EG for landfills; the EPA was able to update its internal landfills data set and consider the technical attributes of over 1,200 landfills based on data reported under subpart HH. The benefits of improved reporting also include enhancing existing voluntary programs, such as the Landfill Methane Outreach Program (LMOP), which uses GHGRP data to supplement the LMOP Landfill and Landfill Gas Energy Project Database and includes data collected from LMOP Partners about landfill gas energy projects or potential for project development.

The final rule would additionally benefit states by providing improved facility-specific emissions data. Several states use GHGRP data to inform their own policymaking. For example, the state of Hawaii uses GHGRP data to establish an emissions baseline for each facility subject to their GHG Reduction Plan and to assess whether facilities meet their targets in future years.

GHGRP data are also used to improve estimates of GHG emissions internationally. Data collected through the GHGRP complements the Inventory and are used to significantly improve our understanding of key emissions sources by allowing the EPA to better reflect changing technologies and emissions from a wide range of industrial facilities. Specifically, GHGRP data have been used to inform several of the updates to emission estimation methods included in the 2019 Refinement.

Benefits to industry of improved GHG emissions monitoring and reporting from the amendments include the value of having standardized emissions data to present to the public to demonstrate appropriate environmental stewardship, and a better understanding of their emission levels and sources to identify opportunities to reduce emissions. For example, the final rule updates the global warming potential values used under the GHGRP to reflect values from the IPCC AR5 and AR6, which are consistent with the values used under several voluntary standards and frameworks such as the GHG Protocol and Sustainability Accounting Standards Board (SASB), and will provide consistency for company reporting. Businesses and other innovators can use the data to determine and track their GHG footprints, find cost-saving efficiencies that reduce GHG emissions and save product, foster technologies to protect public health and the environment, and to reduce costs associated with fugitive emissions. The final rule will continue to allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry and achieve and disseminate information about their environmental performance.

In addition, transparent, standardized public data on emissions allows for accountability of polluters to the public who bear the cost of the pollution. The GHGRP serves as a powerful data resource and provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments. As discussed in section II. of this preamble, GHGRP data are easily accessible to the public via the EPA's FLIGHT, which allows users to view and sort GHG data by location, industrial sector, and type of GHG emitted, and includes demographic data. Although the emissions reported to the EPA by reporting facilities are global pollutants, many of these facilities also release pollutants that have a more direct and local impact in the surrounding communities. Citizens, community groups, and labor unions have made use of public pollutant release data to negotiate directly with emitters to lower emissions, avoiding the need for additional regulatory action. The final rule would improve the quality and transparency of this reported data to affected communities.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and 14094: Modernizing Regulatory Review

This action is not a significant regulatory action as defined in Executive Order 12866, as amended by Executive Order 14094, and was therefore not subject to a requirement for Executive Order 12866 review.

B. Paperwork Reduction Act

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned OMB number 2060–0748, EPA ICR number 2773.02. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The EPA has estimated that the final rule will result in an increase in burden, specifically in cases where the amendments expand the applicability, monitoring, or reporting requirements of part 98. In some cases, the final amendments are anticipated to decrease burden where we streamlined the rule to remove notification or reporting requirements or simplify monitoring and reporting requirements. The final rule consolidates amendments from the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal that revise 31 subparts that directly affect 30 industries—including revisions to update the GWPs in table A–1 to subpart A of part 98 that affect the number of facilities required to report under part 98; revisions to implement five new source categories or to expand existing source categories that may require facilities to newly report; and revisions to add new reporting requirements that will improve the quality of the data collected under part 98. The costs associated with the final rule largely reflect the costs to facilities that would be required to newly report under part 98. However, the majority of subparts affected will reflect a modest increase in burden to existing individual reporters.

Further information on the EPA's assessment on the impact on burden can be found in the memorandum ''Assessment of Burden Impacts for Final Revisions for the Greenhouse Gas Reporting Rule,'' available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2019–0424).

Respondents/affected entities: Owners and operators of facilities that must report their GHG emissions and other data to the EPA to comply with 40 CFR part 98.

Respondent's obligation to respond: The respondent's obligation to respond is mandatory and the requirements in this rule are under the authority provided in CAA section 114.

Estimated number of respondents: 2,701.

Frequency of response: Initially, annually.

Total estimated burden: 25,647 hours (annual average per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $5,410,000 (annual average per year), includes $2,734,000 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this final action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses across all sectors encompassed by the rule, small governmental jurisdictions, and small non-profits. In the development of 40 CFR part 98, the EPA determined that some small entities are affected because their production processes emit GHGs that must be reported, because they have stationary combustion units on site that emit GHGs that must be reported, or because they have fuel supplier operations for which supply quantities and GHG data must be reported. Small governments and small non-profits are generally affected because they have regulated landfills or stationary combustion units on site, or because they own a local distribution company (LDC).

The EPA previously conducted screening analyses to identify impacts to small entities during the development of the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal. The EPA conducted small entity analyses that assessed the costs and impacts to small entities in three areas, including: (1) amendments that revise the number or types of facilities required to report (*i.e.,* updates of the GHGRP's applicability to certain sources), (2) changes to refine existing monitoring or calculation methodologies that require collection of additional data, and (3) revisions to reporting and recordkeeping requirements for data provided to the program. The analyses provided the subparts affected, the number of small entities affected, and the estimated impact to these entities based on the total annualized reporting costs of the proposed rules. Details of these analyses are presented in the memoranda, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* (May 2022) and *Assessment of Burden Impacts for Proposed Supplemental Revisions for the Greenhouse Gas Reporting Rule* (April 2023), available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2019–0424). Based on the results of these analyses, we concluded that the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal will have no significant regulatory burden for any directly regulated small entities and thus would not have a significant economic impact on a substantial number of small entities.

As discussed in sections III. and VII. of this preamble, this action finalizes revisions to part 98 as proposed in the 2022 Data Quality Improvements Proposal and the 2023 Supplemental Proposal, or with minor revisions, and we have revised the cost impacts to reflect the final rule requirements and more recent data. For example, we have updated the impacts to better reflect the number of affected reporters that would be subject to the final requirements, based on a review of RY2022 data. These updates also predominantly include removing or adjusting costs where the EPA is not taking final action on specific proposed revisions, including costs associated with the addition of proposed subpart B (Energy Consumption), certain costs associated with proposed revisions to subpart W (Petroleum and Natural Gas Systems) included in the 2022 Data Quality Improvements Proposal,[50] and costs associated with certain revisions to calculations, monitoring, or reporting requirements for subparts A (General Provisions), C (General Stationary Fuel Combustion), F (Aluminum Production), G (Ammonia Production), H (Cement Production), S (Lime Production), HH (Municipal Waste Landfills), OO (Suppliers of Industrial Greenhouse Gases), and QQ (Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment and Closed-Cell Foams). Accordingly, the burden of the final rule is reduced, as compared to the proposals, for facilities that may report for these source categories, including all direct emitting facilities previously proposed to report under subpart B.

The EPA has also adjusted the burden to account for additional costs from changes adopted in the final rule. Specifically, we have adjusted the reporting and recordkeeping requirements for subparts I (Electronics Manufacturing), P (Hydrogen Production), DD (Electrical Transmission and Distribution Equipment Use), HH (Municipal Solid Waste Landfills), and ZZ (Ceramics Manufacturing) to add new data elements for annual reporting across these subparts. The estimated costs associated with the revisions to these subparts for regulated entities are minimal (less than $100 annually), and would not result in costs exceeding more than one percent of sales in any firm size category. Details of this analysis are presented in the memorandum ''Assessment of Burden Impacts for Final Revisions for the Greenhouse Gas Reporting Rule,'' available in Docket ID. No. EPA–HQ–OAR–2019–0424.

The remaining revisions to the final rule include minor clarifications or adjustments to the proposed requirements that are not anticipated to increase the burdens estimated for the 2022 Data Quality Improvements Proposal and 2023 Supplemental Proposal which we previously determined would not have a significant impact on a significant number of small businesses. For these reasons, we have determined that these final revisions are consistent with our prior small entity analyses, and would impose no significant regulatory burden on any directly regulated small entities, and thus would not have a significant economic impact on a substantial number of small entities.

Refer to the memorandum ''Assessment of Burden Impacts for Final Revisions for the Greenhouse Gas Reporting Rule,'' available in Docket ID. No. EPA–HQ–OAR–2019–0424 for further discussion. The EPA continues to conduct significant outreach on the GHGRP and maintains an ''open door'' policy for stakeholders to help inform the EPA's understanding of key issues for the industries.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

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[50] The EPA is not taking final action on any revisions to requirements for subpart W (Petroleum and Natural Gas Systems) in this final rule. See sections I.C. and VII. of this preamble for additional information regarding the EPA's actions regarding subpart W and the impacts included in this final rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This regulation will apply directly to facilities emitting and supplying GHGs that may be owned by tribal governments that emit GHGs. However, it will only have tribal implications where the tribal entity owns a facility that directly emits GHGs above threshold levels; therefore, relatively few (approximately 10) tribal facilities will be affected. This regulation is not anticipated to impact facilities or suppliers of additional sectors owned by tribal governments.

In evaluating the potential implications for tribal entities, we first assessed whether tribes would be affected by any final revisions that expanded the universe of facilities that would report GHG data to the EPA. The final rule amendments will implement requirements to collect additional data to understand new source categories, new sources of GHG emissions or supply for specific sectors; improve the existing emissions estimation methodologies; and improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates and improve verification of collected data. Of the 254 facilities that we anticipate will be newly required to report under the final revisions, we do not anticipate that there are any tribally owned facilities. As discussed in section VII. of this preamble, we expect the final revisions to table A–1 to part 98 to result in a change to the number of facilities required to report under subparts W (Petroleum and Natural Gas Systems), V (Nitric Acid Production), DD (Electrical Transmission and Distribution Equipment Use), HH (MSW Landfills), II (Industrial Wastewater Treatment), OO (Suppliers of Industrial GHGs), and TT (Industrial Waste Landfills). However, we did not identify any potential sources in these source categories that are owned by tribal entities not already reporting to the GHGRP. Similarly, although we are finalizing amendments that will require some facilities in select source categories not currently subject to the GHGRP to begin implementing requirements under the program, we have not identified, and do not anticipate that any of these affected facilities are owned by tribal governments.

As a second step to evaluate potential tribal implications, we evaluated whether there were any tribally owned facilities that are currently reporting under the GHGRP that will be affected by the final revisions. Tribally owned facilities currently subject to part 98 will only be subject to changes that are improvements or clarifications of requirements and that, for the most part, do not significantly change the existing requirements or result in substantial new activities because they do not require new equipment, sampling, or monitoring. Rather, tribally owned facilities would only be subject to new requirements where reporters would provide data that is readily available from company records. As such, the final revisions will not substantially increase reporter burden, impose significant direct compliance costs for tribal facilities, or preempt tribal law.

Specifically, we identified ten facilities currently reporting to part 98 that are owned by six tribal parent companies. For these six parent companies, we identified facilities in the stationary fuel combustion (subpart C), cement production (subpart H), petroleum and natural gas (subpart W), electrical transmission and distribution equipment use (subpart DD), and MSW landfill (subpart HH) source categories that may be affected by the final revisions.

For stationary fuel combustion, the EPA is not taking final action on proposed revisions to add reporting requirements to subpart C, but is retaining revisions that would remove certain reporting requirements. Therefore, the costs for any tribally-owned facilities currently reporting to subpart C are anticipated to decrease and no facilities are anticipated to be negatively impacted. For petroleum and natural gas facilities, the EPA is not including any revisions to subpart W in this final rule (see section I.C. of this document); therefore, any tribally-owned facilities currently reporting to subpart W are not anticipated to be impacted. Three parent companies include existing facilities that report only under subparts C or W, which are not anticipated to have significant impacts under this rule for the reasons discussed in this section. Therefore, the remaining facilities that could be affected by the final revisions are those that report to subparts H, DD, and HH. For the remaining three parent companies, we reviewed publicly available sales and revenue data to assess whether the costs of the final rule would be significant. Under the final rule, the costs for facilities currently reporting under subparts H, DD, or HH are anticipated to increase by less than $100 per year per subpart. Therefore, we were able to confirm that the costs of the final revisions would not have a significant impact for these sources. Further, based on our review of our small entity analyses (discussed in VIII.C. of this preamble), we do not anticipate the final revisions to subparts H, DD, or HH will impose substantial direct compliance costs on the remaining tribally owned entities.

Although few facilities subject to part 98 are likely to be owned by tribal governments, the EPA previously sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final rules for part 98 subparts that were promulgated on October 30, 2009 (74 FR 52620), July 12, 2010 (75 FR 39736), November 30, 2010 (75 FR 74458), and December 1, 2010 (75 FR 74774 and 75 FR 75076). Consistent with the 2011 EPA Policy on Consultation and Coordination with Indian Tribes,[51] the EPA previously consulted with tribal officials early in the process of developing part 98 regulations to permit them to have meaningful and timely input into its development and to provide input on the key regulatory requirements established for these facilities. A summary of these consultations is provided in section VIII.F. of the preamble to the final rule published on October 30, 2009 (74 FR 52620), section V.F. of the preamble to the final rule published on July 12, 2010 (75 FR 39736), section IV.F. of the preamble to the re-proposal of subpart W (Petroleum and Natural Gas Systems) published on April 12, 2010 (75 FR 18608), and section IV.F. of the preambles to the final rules published on December 1, 2010 (75 FR 74774 and 75 FR 75076). As described in this section, the final rule does not significantly revise the established regulatory requirements and will not substantially change the equipment, monitoring, or reporting activities conducted by these facilities, or result in other substantial impacts for tribal facilities.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory

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[51] EPA Policy on Consultation and Coordination with Indian Tribes, May 4, 2011. Available at: *www.epa.gov/sites/default/files/2013-08/documents/cons-and-coord-with-indian-tribes-policy.pdf.*

action'' in section 2–202 of the Executive order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act and 1 CFR Part 51

This action involves technical standards. The EPA has decided to incorporate by reference several standards in establishing monitoring requirements in these final amendments.

The EPA currently allows for the use of the *Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing, Version 1,* EPA–430–R–10–003, March 2010 (EPA 430–R–10–003) in other sections of part 98, including subpart I (Electronics Manufacturing). The EPA is adding the use of EPA 430–R–10–003 to subpart I for use for measurement of DREs from abatement systems, including HC fuel CECS, purchased and installed on or after January 1, 2025. EPA 430–R–10–003 provides methods for measuring abatement system inlet and outlet mass or volume flows for single or multi-chamber process tools, accounting for dilution. Anyone may access EPA 430–R–10–003 at *https://www.epa.gov/sites/default/files/2016-02/documents/dre_protocol.pdf.* This standard is available to everyone at no cost; therefore, the method is reasonably available for reporters.

The EPA is allowing the use of an alternate method, ASTM E415–17, *Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry* (2017), for the purposes of subpart Q (Iron and Steel Production) monitoring and reporting. The EPA currently allows for the use of ASTM E415–17 in other sections of part 98, including under 40 CFR 98.144(b) where it can be used to determine the composition of coal, coke, and solid residues from combustion processes by glass production facilities. Therefore, the EPA is allowing ASTM E415–17 to be used in subpart Q. ASTM E415–17 uses spark atomic emission vacuum spectrometry to determine 21 alloying and residual elements in carbon and low-alloy steels. The method is designed for chill-cast, rolled, and forged specimens. (See the end of section VIII.I. of this preamble for availability information.)

The EPA is adding new subpart VV to part 98 for certain EOR operations that choose to use the co-published ISO/CSA standard designated as CSA/ANSI ISO 27916:19, *Carbon dioxide capture, transportation and geological storage—Carbon dioxide storage using enhanced oil recovery (CO_2–EOR),* as a means of quantifying geologic sequestration. The EPA is also clarifying in subpart UU at 40 CFR 98.470(c) and subpart VV at 40 CFR 98.481 that CO_2–EOR projects previously reporting under subpart UU that begin using CSA/ANSI ISO 27916:19 part-way through a reporting year must report under subpart UU for the portion of the year before CSA/ANSI ISO 27916:19 was used and report under subpart VV for the portion of the year once CSA/ANSI ISO 27916:19 began to be used and thereafter. CSA/ANSI ISO 27916:19 identifies and quantifies CO_2 losses (including fugitive emissions) and quantifies the amount of CO_2 stored in association with the CO_2-EOR project. It also shows how allocation rations can be used to account for the anthropogenic portion of the stored CO_2. Anyone may access the standard on the CSA group website (*www.csagroup.org/store*) for additional information. The standard is available to everyone at a cost determined by CSA Group ($225). CSA Group also offers memberships or subscriptions for reduced costs. Because the use of the standard is optional, the cost of obtaining this standard is not a significant financial burden.

The EPA is adding new subpart WW to part 98 (Coke Calciners) and is allowing the use of any one of the following standards for coke calcining facilities: (1) ASTM D3176–15 *Standard Practice for Ultimate Analysis of Coal and Coke,* (2) ASTM D5291–16 *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants,* and (3) ASTM D5373–21 *Standard Test Methods for Determination of Carbon, Hydrogen, and Nitrogen in Analysis Samples of Coal and Carbon in Analysis Samples of Coal and Coke.* These methods are used to determine the carbon content of petroleum coke. The EPA currently allows for the use of an earlier version of these standard methods for the instrumental determination of carbon content in laboratory samples of petroleum coke in other sections of part 98, including the use of ASTM D3176–89, ASTM D5291–02, and ASTM D5373–08 in 40 CFR 98.244(b) (subpart X—Petrochemical Production) and 40 CFR 98.254(i) (subpart Y—Petroleum Refineries). The EPA is allowing the use of the updated versions of these standards (ASTM D3176–15, ASTM D5291–16, and ASTM D5373–21) to determine the carbon content of petroleum coke for subpart WW (Coke Calciners). ASTM D3176–15 provides direction for a convenient and uniform system of analysis of the ash content and the content of organic constituents in coal and coke; this method references the appropriate ASTM methods for sample collection, preparation, content determination, and provides consistency measures for calculation and reporting of results. ASTM D5291–16 provides a series of test methods for the simultaneous instrumental determination of carbon, hydrogen, and nitrogen in petroleum products and lubricants such as crude oils, fuel oils, additives, and residues; the method allows for a variety of instrumental components and configurations for measurement and calculation of concentrations of carbon, hydrogen, and nitrogen. ASTM D5373–21 provides a methodology for the determination of carbon, hydrogen, and nitrogen content in coal or carbon in coke using furnace combustion and instrument detection systems; the method addresses the determination of carbon in the range of 54.9 percent m/m to 84.7 percent m/m, hydrogen in the range of 3.26 percent m/m to 5.08 percent m/m, and nitrogen in the range of 0.57 percent m/m to 1.76 percent m/m in the analysis sample of coal. (See the end of section VIII.I. of this preamble for availability information.)

We are allowing the use of the following standard for coke calciners subject to subpart WW: NIST HB 44–2023, NIST Handbook 44: *Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices,* 2023 edition. The EPA currently allows for the use of an earlier version of the proposed standard method, *Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44* (2009), for the calibration and maintenance of instruments used for weighing of mass of samples of petroleum coke in other sections of part 98, including 40 CFR 98.244(b) (subpart X). The EPA is allowing the use of the updated version of this standard, NIST HB 44–2023: *Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices,* 2023 edition, for performing mass measurements of petroleum coke for subpart WW (Coke Calciners). This standard includes specifications on design of equipment, tolerances to limit the allowable error, sensitivity requirements, and other technical requirements for weighing and measuring devices. Anyone may access the standards on the NIST website (*www.nist.gov/index.html*) for additional information. These standards are available to everyone at no cost; therefore the methods are reasonably available for reporters.

The EPA is adding new subpart XX to part 98 (Calcium Carbide Production) and is allowing the use of one of the following standards for calcium carbide production facilities: (1) ASTM D5373–08 *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal,* or (2) ASTM C25–06, *Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.* ASTM D5373–08 addresses the determination of carbon in the range of 54.9 percent m/m to 84.7 percent m/m, hydrogen in the range of 3.25 percent m/m to 5.10 percent m/m, and nitrogen in the range of 0.57 percent m/m to 1.80 percent m/m in the analysis sample of coal. The EPA currently allows for the use of ASTM D5373–08 in other sections of part 98, including in 40 CFR 98.244(b) (subpart X—Petrochemical Production), 40 CFR 98.284(c) (subpart BB—Silicon Carbide Production), and 40 CFR 98.314(c) (subpart EE—Titanium Production) for the instrumental determination of carbon content in laboratory samples. Therefore, we are allowing the use of ASTM D5373–08 for determination of carbon content of materials consumed, used, or produced at calcium carbide facilities.

The EPA currently allows for the use of ASTM C25–06 in other sections of part 98, including in 40 CFR 98.194(c) (subpart S—Lime Production) for chemical composition analysis of lime products and calcined byproducts and in 40 CFR 98.184(b) (subpart R—Lead Production) for analysis of flux materials such as limestone or dolomite. ASTM C25–06 addresses the chemical analysis of high-calcium and dolomitic limestone, quicklime, and hydrated lime. We are allowing the use of ASTM C25–06 for determination of carbon content of materials consumed, used, or produced at calcium carbide facilities, including analysis of materials such as limestone or dolomite.

Anyone may access the standards on the ASTM website (*www.astm.org/*) for additional information. These standards are available to everyone at a cost determined by the ASTM (between $48 and $92 per standard). The ASTM also offers memberships or subscriptions that allow unlimited access to their methods. The cost of obtaining these methods is not a significant financial burden, making the methods reasonably available for reporters.

The EPA will also make a copy of these documents available in hard copy at the appropriate EPA office (see the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information) for review purposes only. The EPA is not requiring the use of specific consensus standards for new subparts YY (Caprolactam, Glyoxal, and Glyoxylic Acid Production) or ZZ (Ceramics Manufacturing), or for other amendments to part 98.

The following standards appear in the amendatory text of this document and were previously approved for the locations in which they appear:

- ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke;
- ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants;
- ASTM E1019–08 Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques;
- Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009);
- ASTM D6866–16 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis).
- ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.
- ASTM D2505–88 (Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.
- T650 om–05 Solids Content of Black Liquor, TAPPI.

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

The EPA believes that this type of action does not directly concern human health or environmental conditions and therefore cannot be evaluated with respect to potentially disproportionate and adverse effects on communities with environmental justice concerns. This action does not affect the level of protection provided to human health or the environment, but instead, addresses information collection and reporting procedures. Although this action does not concern human health or environmental conditions, the EPA identified and addressed environmental justice concerns by promoting meaningful engagement from communities in developing the action, and in developing requirements that improve the quality of data available to communities. The EPA provided multiple public comment periods on the proposed 2022 Data Quality Improvements Proposal (from June 21, 2022 to October 6, 2022) and the 2023 Supplemental Proposal (May 22, 2023 to July 21, 2023), and provided opportunities for virtual public hearing(s) for members of the public to share information or concerns and participate in the decision-making process. Further, the EPA has developed improvements to the GHGRP that benefit the public by increasing the completeness and accuracy of facility emissions data. The data collected through this action will provide an important data resource for communities and the public to understand GHG emissions, including requiring reporting of GHG data from additional emission sources and providing more comprehensive coverage of U.S. GHG emissions. Transparent, standardized public data on emissions allows for accountability of polluters to the public who bear the cost of the pollution. Although the emissions reported to the EPA by reporting facilities are global pollutants, many of these facilities also release pollutants that have a more direct and local impact in the surrounding communities. GHGRP data are easily accessible to the public via the EPA's online data publication tool (FLIGHT), which allows users to view and sort GHG data from over 8,000 entities in a variety of ways including by location, industrial sector, type of GHG emitted, and provides supplementary demographic data that may be useful to communities with environmental justice concerns. As described further in sections II. and III. of this preamble, the final rule improves the quality and transparency of this reported data to affected communities and enables members of the public to have access to and improve their understanding of GHG emissions and pollutants that may impact them.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the

Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

L. Judicial Review

Under CAA section 307(b)(1), any petition for review of this final rule must be filed in the U.S. Court of Appeals for the District of Columbia Circuit by June 24, 2024. This final rule establishes requirements applicable to owners and operators of facilities and suppliers in many industry source categories located across the United States that are subject to 40 CFR part 98 and therefore is ''nationally applicable'' within the meaning of CAA section 307(b)(1).

Further, pursuant to CAA section 307(d)(1)(V), the Administrator has determined that this rule is subject to the provisions of CAA section 307(d). See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine''). Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. CAA section 307(d)(7)(B) also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with an electronic copy to the person listed in **FOR FURTHER INFORMATION CONTACT**, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20004. Note that under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

List of Subjects

40 CFR Part 9

Environmental protection, Administrative practice and procedure, Reporting and recordkeeping requirements.

40 CFR Part 98

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

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends title 40, chapter I, of the Code of Federal Regulations as follows:

PART 9—OMB APPROVALS UNDER THE PAPERWORK REDUCTION ACT

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

Authority: 7 U.S.C. 135 *et seq.,* 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 31 U.S.C. 9701; 33 U.S.C. 1251 *et seq.,* 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345(d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857 *et seq.,* 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

■ 2. Amend § 9.1 by adding an undesignated center heading and an entry for ''98.1–98.528'' in numerical order to read as follows:

§ 9.1 OMB approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * *	* *
Mandatory Greenhouse Gas Reporting	
98.1–98.528	2060–0629
* * *	* *

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 3. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—General Provision

■ 4. Amend § 98.2 by:
■ a. Revising paragraphs (f)(1) and (i)(1) and (2); and
■ b. Adding paragraph (k).
The revisions and addition read as follows:

§ 98.2 Who must report?

* * * * *

(f) * * *

(1) Calculate the mass in metric tons per year of CO_2, N_2O, each fluorinated GHG, and each fluorinated heat transfer fluid that is imported and the mass in metric tons per year of CO_2, N_2O, each fluorinated GHG, and each fluorinated heat transfer fluid that is exported during the year.

* * * * *

(i) * * *

(1) If reported CO_2e emissions, calculated in accordance with § 98.3(c)(4)(i), are less than 25,000 metric tons per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the five consecutive years prior to notification of discontinuation of reporting and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual CO_2e emissions, calculated in accordance with paragraph (b)(4) of this section, in any future calendar year increase to 25,000 metric tons per year or more.

(2) If reported CO_2e emissions, calculated in accordance with § 98.3(c)(4)(i), were less than 15,000 metric tons per year for three consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than 15,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the three consecutive years and retain such records for three years prior to notification of discontinuation of reporting following the year that reporting was discontinued. The owner

or operator must resume reporting if annual CO_2e emissions, calculated in accordance with paragraph (b)(4) of this section, in any future calendar year increase to 25,000 metric tons per year or more.

* * * * *

(k) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold under paragraph (a)(4) of this section for facilities that destroy fluorinated GHGs or fluorinated heat transfer fluids, the owner or operator shall calculate the mass in metric tons per year of CO_2e destroyed as described in paragraphs (k)(1) through (3) of this section.

(1) Calculate the mass in metric tons per year of each fluorinated GHG or fluorinated heat transfer fluid that is destroyed during the year.

(2) Convert the mass of each destroyed fluorinated GHG or fluorinated heat transfer fluid from paragraph (k)(1) of this section to metric tons of CO_2e using equation A–1 to this section.

(3) Sum the total annual metric tons of CO_2e in paragraph (k)(2) of this section for all destroyed fluorinated GHGs and destroyed fluorinated heat transfer fluids.

■ 5. Amend § 98.3 by:

■ a. Revising paragraphs (b)(2), (h)(4), and (k)(1) through (3); and

■ b. Revising and republishing paragraph (l).

The revisions and republication read as follows:

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

* * * * *

(b) * * *

(2) For a new facility or supplier that begins operation on or after January 1, 2010 and becomes subject to the rule in the year that it becomes operational, report emissions starting 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.

* * * * *

(h) * * *

(4) Notwithstanding paragraphs (h)(1) and (2) of this section, upon request by the owner or operator, the Administrator may provide reasonable extensions of the 45-day period for submission of the revised report or information under paragraphs (h)(1) and (2) of this section. If the Administrator receives a request for extension of the 45-day period, by email to an address prescribed by the Administrator prior to the expiration of the 45-day period, the extension request is deemed to be automatically granted for 30 days. The Administrator may grant an additional extension beyond the automatic 30-day extension if the owner or operator submits a request for an additional extension and the request is received by the Administrator prior to the expiration of the automatic 30-day extension, provided the request demonstrates that it is not practicable to submit a revised report or information under paragraphs (h)(1) and (2) of this section within 75 days. The Administrator will approve the extension request if the request demonstrates to the Administrator's satisfaction that it is not practicable to collect and process the data needed to resolve potential reporting errors identified pursuant to paragraph (h)(1) or (2) of this section within 75 days. The Administrator will only approve an extension request for a total of 180 days after the initial notification of a substantive error.

* * * * *

(k) * * *

(1) A facility or supplier that first becomes subject to part 98 due to a change in the GWP for one or more compounds in table A–1 to this subpart, Global Warming Potentials, is not required to submit an annual GHG report for the reporting year during which the change in GWPs is published in the **Federal Register** as a final rulemaking.

(2) A facility or supplier that was already subject to one or more subparts of this part but becomes subject to one or more additional subparts due to a change in the GWP for one or more compounds in table A–1 to this subpart, is not required to include those subparts to which the facility is subject only due to the change in the GWP in the annual GHG report submitted for the reporting year during which the change in GWPs is published in the **Federal Register** as a final rulemaking.

(3) Starting on January 1 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking, facilities or suppliers identified in paragraph (k)(1) or (2) of this section must start monitoring and collecting GHG data in compliance with the applicable subparts of part 98 to which the facility is subject due to the change in the GWP for the annual greenhouse gas report for that reporting year, which is due by March 31 of the following calendar year.

* * * * *

(l) *Special provision for best available monitoring methods in 2014 and subsequent years.* This paragraph (l) applies to owners or operators of facilities or suppliers that first become subject to any subpart of this part due to an amendment to table A–1 to this subpart, Global Warming Potentials.

(1) *Best available monitoring methods.* From January 1 to March 31 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking, owners or operators subject to this paragraph (l) may use best available monitoring methods for any parameter (*e.g.,* fuel use, feedstock rates) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the ''Calculating GHG Emissions'' sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking. Starting no later than April 1 of the year after the year during which the change in GWPs is published, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraph (l)(2) of this section. Best available monitoring methods means any of the following methods:

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

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Requests for extension of the use of best available monitoring methods.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking.

(i) *Timing of request.* The extension request must be submitted to EPA no later than January 31 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking.

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

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

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

(C) A description of the reasons that the needed equipment could not be obtained and installed before April 1 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between November 29 of the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking and April 1 of the year after the year during which the change in GWPs is published, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1 of the year after the year during which the change in GWPs is published in the **Federal Register** as a final rulemaking. The use of best available methods under this paragraph (l) will not be approved beyond December 31 of the year after the year during which the change in GWPs is published.

■ 6. Amend § 98.5 by revising paragraph (b) to read as follows:

§ 98.5 How is the report submitted?

* * * * *

(b) For reporting year 2014 and thereafter, unless a later year is specified in the applicable recordkeeping section, you must enter into verification software specified by the Administrator the data specified as verification software records in each applicable recordkeeping section. For each data element entered into the verification software, if the software produces a warning message for the data value and you elect not to revise the data value, you may provide an explanation in the verification software of why the data value is not being revised.

■ 7. Amend § 98.6 by:

■ a. Revising the definitions ''ASTM'', ''Bulk'', and ''Carbon dioxide stream'';

■ b. Adding the definitions ''Cyclic'' and ''Direct air capture (DAC)'' in alphabetical order;

■ c. Removing the definition ''Fluorinated greenhouse gas'';

■ d. Adding the definition ''Fluorinated greenhouse gas (GHG)'' in alphabetical order;

■ e. Revising the definition ''Fluorinated greenhouse gas (GHG) group'';

■ f. Adding the definition ''Fluorinated heat transfer fluids'' in alphabetic order;

■ g. Revising the definition ''Greenhouse gas or GHG'';

■ h. Removing the definition ''Other fluorinated GHGs'';

■ i. Revising the definition ''Process vent''; and

■ j. Adding definitions ''Remaining fluorinated GHGs'', ''Saturated chlorofluorocarbons (CFCs)'', ''Unsaturated bromochlorofluorocarbons (BCFCs)'', ''Unsaturated bromofluorocarbons (BFCs)'', ''Unsaturated chlorofluorocarbons (CFCs)'', ''Unsaturated hydrobromochlorofluorocarbons (HBCFCs)'', and ''Unsaturated hydrobromofluorocarbons (HBFCs)'' in alphabetic order.

The revisions and additions read as follows:

§ 98.6 Definitions.

* * * * *

ASTM means ASTM, International.

* * * * *

Bulk, with respect to industrial GHG suppliers and CO_2 suppliers, means a transfer of gas in any amount that is in a container for the transportation or storage of that substance such as cylinders, drums, ISO tanks, and small cans. An industrial gas or CO_2 that must first be transferred from a container to another container, vessel, or piece of equipment in order to realize its intended use is a bulk substance. An industrial GHG or CO_2 that is contained in a manufactured product such as electrical equipment, appliances, aerosol cans, or foams is not a bulk substance.

* * * * *

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (*e.g.,* a power plant or other industrial facility), captured from ambient air (*e.g.,* direct air capture), 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.

* * * * *

Cyclic, in the context of fluorinated GHGs, means a fluorinated GHG in which three or more carbon atoms are connected to form a ring.

* * * * *

Direct air capture (DAC), with respect to a facility, technology, or system, means that the facility, technology, or system uses carbon capture equipment to capture carbon dioxide directly from the air. Direct air capture does not include any facility, technology, or system that captures carbon dioxide:

(1) That is deliberately released from a naturally occurring subsurface spring; or

(2) Using natural photosynthesis.

* * * * *

Fluorinated greenhouse gas (GHG) means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF3), and any fluorocarbon except for controlled substances as defined at part 82, subpart A of this subchapter and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C. With these exceptions, ''fluorinated GHG'' includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

Fluorinated greenhouse gas (GHG) group means one of the following sets of fluorinated GHGs:

(1) Fully fluorinated GHGs;

(2) Saturated hydrofluorocarbons with two or fewer carbon-hydrogen bonds;

(3) Saturated hydrofluorocarbons with three or more carbon-hydrogen bonds;

(4) Saturated hydrofluoroethers and hydrochlorofluoroethers with one carbon-hydrogen bond;

(5) Saturated hydrofluoroethers and hydrochlorofluoroethers with two carbon-hydrogen bonds;

(6) Saturated hydrofluoroethers and hydrochlorofluoroethers with three or more carbon-hydrogen bonds;

(7) Saturated chlorofluorocarbons (CFCs);

(8) Fluorinated formates;

(9) Cyclic forms of the following: unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated CFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated bromofluorocarbons (BFCs), unsaturated bromochlorofluorocarbons (BCFCs), unsaturated hydrobromofluorocarbons (HBFCs), unsaturated hydrobromochlorofluorocarbons (HBCFCs), unsaturated halogenated ethers, and unsaturated halogenated esters;

(10) Fluorinated acetates, carbonofluoridates, and fluorinated alcohols other than fluorotelomer alcohols;

(11) Fluorinated aldehydes, fluorinated ketones and non-cyclic forms of the following: unsaturated PFCs, unsaturated HFCs, unsaturated CFCs, unsaturated HCFCs, unsaturated BFCs, unsaturated BCFCs, unsaturated HBFCs, unsaturated HBCFCs, unsaturated halogenated ethers, and unsaturated halogenated esters;

(12) Fluorotelomer alcohols;

(13) Fluorinated GHGs with carbon-iodine bonds; or

(14) Remaining fluorinated GHGs.

Fluorinated heat transfer fluids means fluorinated GHGs used for temperature control, device testing, cleaning substrate surfaces and other parts, other solvent applications, and soldering in certain types of electronics manufacturing production processes and in other industries. Fluorinated heat transfer fluids do not include fluorinated GHGs used as lubricants or surfactants in electronics manufacturing. For fluorinated heat transfer fluids, the lower vapor pressure limit of 1 mm Hg in absolute at 25 °C in the definition of ‘‘fluorinated greenhouse gas’’ in this section shall not apply. Fluorinated heat transfer fluids include, but are not limited to, perfluoropolyethers (including PFPMIE), perfluoroalkylamines, perfluoroalkylmorpholines, perfluoroalkanes, perfluoroethers, perfluorocyclic ethers, and hydrofluoroethers. Fluorinated heat transfer fluids include HFC–43–10meee but do not include other hydrofluorocarbons.

* * * * *

Greenhouse gas or *GHG* means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated greenhouse gases (GHGs) as defined in this section.

* * * * *

Process vent means a gas stream that: Is discharged through a conveyance to the atmosphere either directly or after passing through a control device; originates from a unit operation, including but not limited to reactors (including reformers, crackers, and furnaces, and separation equipment for products and recovered byproducts); and contains or has the potential to contain GHG that is generated in the process. Process vent does not include safety device discharges, equipment leaks, gas streams routed to a fuel gas system or to a flare, discharges from storage tanks.

* * * * *

Remaining fluorinated GHGs means fluorinated GHGs that are none of the following:

(1) Fully fluorinated GHGs;

(2) Saturated hydrofluorocarbons with two or fewer carbon-hydrogen bonds;

(3) Saturated hydrofluorocarbons with three or more carbon-hydrogen bonds;

(4) Saturated hydrofluoroethers and hydrochlorofluoroethers with one carbon-hydrogen bond;

(5) Saturated hydrofluoroethers and hydrochlorofluoroethers with two carbon-hydrogen bonds;

(6) Saturated hydrofluoroethers and hydrochlorofluoroethers with three or more carbon-hydrogen bonds;

(7) Saturated chlorofluorocarbons (CFCs);

(8) Fluorinated formates;

(9) Cyclic forms of the following: unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated CFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated bromofluorocarbons (BFCs), unsaturated bromochlorofluorocarbons (BCFCs), unsaturated hydrobromofluorocarbons (HBFCs), unsaturated hydrobromochlorofluorocarbons (HBCFCs), unsaturated halogenated ethers, and unsaturated halogenated esters;

(10) Fluorinated acetates, carbonofluoridates, and fluorinated alcohols other than fluorotelomer alcohols;

(11) Fluorinated aldehydes, fluorinated ketones and non-cyclic forms of the following: unsaturated PFCs, unsaturated HFCs, unsaturated CFCs, unsaturated HCFCs, unsaturated BFCs, unsaturated BCFCs, unsaturated HBFCs, unsaturated HBCFCs, unsaturated halogenated ethers, and unsaturated halogenated esters;

(12) Fluorotelomer alcohols; or

(13) fluorinated GHGs with carbon-iodine bonds.

* * * * *

Saturated chlorofluorocarbons (CFCs) means fluorinated GHGs that contain only chlorine, fluorine, and carbon and that contain only single bonds.

* * * * *

Unsaturated bromochlorofluorocarbons (BCFCs) means fluorinated GHGs that contain only bromine, chlorine, fluorine, and carbon and that contain one or more bonds that are not single bonds.

Unsaturated bromofluorocarbons (BFCs) means fluorinated GHGs that contain only bromine, fluorine, and carbon and that contain one or more bonds that are not single bonds.

Unsaturated chlorofluorocarbons (CFCs) means fluorinated GHGs that contain only chlorine, fluorine, and carbon and that contain one or more bonds that are not single bonds.

* * * * *

Unsaturated hydrobromochlorofluorocarbons (HBCFCs) means fluorinated GHGs that contain only hydrogen, bromine, chlorine, fluorine, and carbon and that contain one or more bonds that are not single bonds.

Unsaturated hydrobromofluorocarbons (HBFCs) means fluorinated GHGs that contain only hydrogen, bromine, fluorine, and carbon and that contain one or more bonds that are not single bonds.

* * * * *

■ 8. Amend § 98.7 by:

■ a. Revising the introductory text;

■ b. Redesignating paragraphs (c) through (e) as paragraphs (b) through (d);

■ c. Revising newly redesignated paragraph (d);

■ d. Adding new paragraph (e); and

■ e. Revising paragraphs (i) and (m)(3).

The revisions and addition read as follows:

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

Certain material is incorporated by reference into this part with the approval of the Director of the **Federal Register** under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the EPA must publish a document in the **Federal Register** and the material must be available to the public. All approved incorporation by reference (IBR) material is available for inspection at the EPA and at the National Archives and Records Administration (NARA). Contact EPA at: EPA Docket Center, Public Reading Room, EPA WJC West, Room 3334, 1301 Constitution Ave. NW, Washington, DC; phone: 202–566–1744; email: *Docket-customerservice@epa.gov;* website: *www.epa.gov/dockets/epa-docket-center-reading-room.* For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations* or email *fr.inspection@nara.gov.* The material may be obtained from the following sources:

* * * * *

(d) ASTM International (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959; (800) 262–1373; *www.astm.org.*

(1) ASTM C25–06, Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime, approved February 15, 2006; IBR approved for §§ 98.114(b); 98.174(b); 98.184(b); 98.194(c); 98.334(b); and 98.504(b).

(2) ASTM C114–09, Standard Test Methods for Chemical Analysis of Hydraulic Cement; IBR approved for § 98.84(a) through (c).

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

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

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

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

(7) ASTM D1826–94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter; IBR approved for § 98.254(e).

(8) ASTM D1836–07, Standard Specification for Commercial Hexanes; IBR approved for § 98.6.

(9) ASTM D1941–91 (Reapproved 2007), Standard Test Method for Open Channel Flow Measurement of Water with the Parshall Flume, approved June 15, 2007; IBR approved for § 98.354(d).

(10) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography; IBR approved for §§ 98.74(c); 98.164(b); 98.244(b); 98.254(d); 98.324(d); 98.344(b); 98.354(g).

(11) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; IBR approved for §§ 98.74(c); 98.164(b); 98.254(d); 98.324(d); 98.344(b); 98.354(g); 98.364(c).

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

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

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

(15) ASTM D2503–92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure; IBR approved for §§ 98.74(c); 98.254(d)(6).

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

(17) ASTM D2593–93 (Reapproved 2009), Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography, approved July 1, 2009; IBR approved for § 98.244(b).

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

(19) ASTM D2879–97 (Reapproved 2007), Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope (ASTM D2879), approved May 1, 2007; IBR approved for § 98.128.

(20) ASTM D3176–15, Standard Practice for Ultimate Analysis of Coal and Coke, approved January 1, 2015; IBR approved for § 98.494(c).

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

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

(23) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels; IBR approved for § 98.254(e).

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

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

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

(27) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method); IBR approved for § 98.254(e).

(28) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; IBR approved for §§ 98.254(e); 98.324(d).

(29) ASTM D5291–02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants; IBR approved for §§ 98.74(c); 98.164(b); 98.244(b).

(30) ASTM D5291–16, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, approved October 1, 2016; IBR approved for § 98.494(c).

(31) ASTM D5373–08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal, approved February 1, 2008; IBR approved for §§ 98.74(c); 98.114(b); 98.164(b); 98.174(b); 98.184(b); 98.244(b); 98.274(b); 98.284(c) and (d); 98.314(c), (d), and (f); 98.334(b); 98.504(b).

(32) ASTM D5373–21, Standard Test Methods for Determination of Carbon, Hydrogen, and Nitrogen in Analysis Samples of Coal and Carbon in Analysis Samples of Coal and Coke, approved April 1, 2021; IBR approved for § 98.494(c).

(33) ASTM D5614–94 (Reapproved 2008), Standard Test Method for Open Channel Flow Measurement of Water with Broad-Crested Weirs, approved October 1, 2008; IBR approved for § 98.354(d).

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

(35) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared

(FTIR) Spectroscopy; IBR approved for § 98.54(b); table I–9 to subpart I of this part; §§ 98.224(b); 98.414(n).

(36) ASTM D6349–09, Standard Test Method for Determination of Major and Minor Elements in Coal, Coke, and Solid Residues from Combustion of Coal and Coke by Inductively Coupled Plasma—Atomic Emission Spectrometry; IBR approved for § 98.144(b).

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

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

(39) ASTM D6866–16, Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, approved June 1, 2016; IBR approved for §§ 98.34(d) and (e); 98.36(e).

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

(41) ASTM D7359–08, Standard Test Method for Total Fluorine, Chlorine and Sulfur in Aromatic Hydrocarbons and Their Mixtures by Oxidative Pyrohydrolytic Combustion followed by Ion Chromatography Detection (Combustion Ion Chromatography-CIC) (ASTM D7359), approved October 15, 2008; IBR approved for § 98.124(e)(2).

(42) ASTM D7430–08ae1, Standard Practice for Mechanical Sampling of Coal; IBR approved for § 98.164(b).

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

(44) ASTM D7633–10, Standard Test Method for Carbon Black—Carbon Content, approved May 15, 2010; IBR approved for § 98.244(b).

(45) ASTM E359–00 (Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate); IBR approved for § 98.294(a) and (b).

(46) ASTM E415–17, Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry, approved May 15, 2017; IBR approved for § 98.174(b).

(47) ASTM E1019–08, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques; IBR approved for § 98.174(b).

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

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

(50) ASTM UOP539–97, Refinery Gas Analysis by Gas Chromatography; IBR approved for §§ 98.164(b); 98.244(b); 98.254(d); 98.324(d); 98.344(b); 98.354(g).

(e) CSA Group (CSA), 178 Rexdale Boulevard, Toronto, Ontario Canada M9W 183; (800) 463–6727; *https://shop.csa.ca.*

(1) CSA/ANSI ISO 27916:19, Carbon dioxide capture, transportation and geological storage—Carbon dioxide storage using enhanced oil recovery (CO_2–EOR), approved August 30, 2019; IBR approved for §§ 98.470(c); 98.480(a); 98.481(a) through (c); 98.482; 98.483; 98.484; 98.485; 98.486(g); 98.487; 98.488(a)(5); 98.489.

Note 1 to paragraph (e)(1): This standard is also available from ISO as ISO 27916:2019(E).

(2) [Reserved]

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(i) National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899–1070, (800) 877–8339, *www.nist.gov/.*

(1) NIST HB 44–2023: Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, 2023 edition, approved November 18, 2022; IBR approved for § 98.494(b).

(2) Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009); IBR approved for §§ 98.244(b); 98.344(a).

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(m) * * *

(3) Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing, Version 1, EPA–430–R–10–003, March 2010 (EPA 430–R–10–003), approved March 2010; IBR approved for §§ 98.94(e); 98.94(f) and (g); 98.97(b) and (d); 98.98; appendix A to subpart I of this part; §§ 98.124(e); 98.414(n). (Also available from: *www.epa.gov/sites/default/files/2016-02/documents/dre_protocol.pdf.*)

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■ 9. Revise table A–1 to subpart A to read as follows:

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS, 100-YEAR TIME HORIZON

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Chemical-Specific GWPs			
Carbon dioxide	124–38–9	CO_2	1
Methane	74–82–8	CH_4	[a,d] 28
Nitrous oxide	10024–97–2	N_2O	[a,d] 265
Fully Fluorinated GHGs			
Sulfur hexafluoride	2551–62–4	SF_6	[a,d] 23,500
Trifluoromethyl sulphur pentafluoride	373–80–8	SF_5CF_3	[d] 17,400
Nitrogen trifluoride	7783–54–2	NF_3	[d] 16,100
PFC–14 (Perfluoromethane)	75–73–0	CF_4	[a,d] 6,630
PFC–116 (Perfluoroethane)	76–16–4	C_2F_6	[a,d] 11,100
PFC–218 (Perfluoropropane)	76–19–7	C_3F_8	[a,d] 8,900
Perfluorocyclopropane	931–91–9	c-C_3F_6	[d] 9,200
PFC–3–1–10 (Perfluorobutane)	355–25–9	C_4F_{10}	[a,d] 9,200
PFC–318 (Perfluorocyclobutane)	115–25–3	c-C_4F_8	[a,d] 9,540

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS, 100-YEAR TIME HORIZON—Continued

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Perfluorotetrahydrofuran	773–14–8	c-C_4F_8O	[e] 13,900
PFC–4–1–12 (Perfluoropentane)	678–26–2	C_5F_{12}	[a d] 8,550
PFC–5–1–14 (Perfluorohexane, FC–72)	355–42–0	C_6F_{14}	[a d] 7,910
PFC–6–1–12	335–57–9	C_7F_{16}; $CF_3(CF_2)_5CF_3$	[b] 7,820
PFC–7–1–18	307–34–6	C_8F_{18}; $CF_3(CF_2)_6CF_3$	[b] 7,620
PFC–9–1–18	306–94–5	$C_{10}F_{18}$	[d] 7,190
PFPMIE (HT–70)	NA	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	[d] 9,710
Perfluorodecalin (cis)	60433–11–6	Z-$C_{10}F_{18}$	[b d] 7,240
Perfluorodecalin (trans)	60433–12–7	E-$C_{10}F_{18}$	[b d] 6,290
Perfluorotriethylamine	359–70–6	$N(C_2F_5)_3$	[e] 10,300
Perfluorotripropylamine	338–83–0	$N(CF_2CF_2CF_3)_3$	[e] 9,030
Perfluorotributylamine	311–89–7	$N(CF_2CF_2CF_2CF_3)_3$	[e] 8,490
Perfluorotripentylamine	338–84–1	$N(CF_2CF_2CF_2CF_2CF_3)_3$	[e] 7,260
Saturated Hydrofluorocarbons (HFCs) With Two or Fewer Carbon-Hydrogen Bonds			
(4s,5s)-1,1,2,2,3,3,4,5-octafluorocyclopentane	158389–18–5	trans-cyc (-CF2CF2CF2CHFCHF-)	[e] 258
HFC–23	75–46–7	CHF_3	[a d] 12,400
HFC–32	75–10–5	CH_2F_2	[a d] 677
HFC–125	354–33–6	C_2HF_5	[a d] 3,170
HFC–134	359–35–3	$C_2H_2F_4$	[a d] 1,120
HFC–134a	811–97–2	CH_2FCF_3	[a d] 1,300
HFC–227ca	2252–84–8	$CF_3CF_2CHF_2$	[b] 2,640
HFC–227ea	431–89–0	C_3HF_7	[a d] 3,350
HFC–236cb	677–56–5	$CH_2FCF_2CF_3$	[d] 1,210
HFC–236ea	431–63–0	CHF_2CHFCF_3	[d] 1,330
HFC–236fa	690–39–1	$C_3H_2F_6$	[a d] 8,060
HFC–329p	375–17–7	$CHF_2CF_2CF_2CF_3$	[b] 2360
HFC–43–10mee	138495–42–8	$CF_3CFHCFHCF_2CF_3$	[a d] 1,650
Saturated Hydrofluorocarbons (HFCs) With Three or More Carbon-Hydrogen Bonds			
1,1,2,2,3,3-hexafluorocyclopentane	123768–18–3	cyc ($-CF_2CF_2CF_2CH_2CH_2-$)	[e] 120
1,1,2,2,3,3,4-heptafluorocyclopentane	15290–77–4	cyc ($-CF_2CF_2CF_2CHFCH_2-$)	[e] 231
HFC–41	593–53–3	CH_3F	[a d] 116
HFC–143	430–66–0	$C_2H_3F_3$	[a d] 328
HFC–143a	420–46–2	$C_2H_3F_3$	[a d] 4,800
HFC–152	624–72–6	CH_2FCH_2F	[d] 16
HFC–152a	75–37–6	CH_3CHF_2	[a d] 138
HFC–161	353–36–6	CH_3CH_2F	[d] 4
HFC–245ca	679–86–7	$C_3H_3F_5$	[a d] 716
HFC–245cb	1814–88–6	$CF_3CF_2CH_3$	[b] 4,620
HFC–245ea	24270–66–4	$CHF_2CHFCHF_2$	[b] 235
HFC–245eb	431–31–2	$CH_2FCHFCF_3$	[b] 290
HFC–245fa	460–73–1	$CHF_2CH_2CF_3$	[d] 858
HFC–263fb	421–07–8	$CH_3CH_2CF_3$	[b] 76
HFC–272ca	420–45–1	$CH_3CF_2CH_3$	[b] 144
HFC–365mfc	406–58–6	$CH_3CF_2CH_2CF_3$	[d] 804
Saturated Hydrofluoroethers (HFEs) and Hydrochlorofluoroethers (HCFEs) With One Carbon-Hydrogen Bond			
HFE–125	3822–68–2	CHF_2OCF_3	[d] 12,400
HFE–227ea	2356–62–9	$CF_3CHFOCF_3$	[d] 6,450
HFE–329mcc2	134769–21–4	$CF_3CF_2OCF_2CHF_2$	[d] 3,070
HFE–329me3	428454–68–6	$CF_3CFHCF_2OCF_3$	[b] 4,550
1,1,1,2,2,3,3-Heptafluoro-3-(1,2,2,2-tetrafluoroethoxy)-propane.	3330–15–2	$CF_3CF_2CF_2OCHFCF_3$	[b] 6,490
Saturated HFEs and HCFEs With Two Carbon-Hydrogen Bonds			
HFE–134 (HG–00)	1691–17–4	CHF_2OCHF_2	[d] 5,560
HFE–236ca	32778–11–3	$CHF_2OCF_2CHF_2$	[b] 4,240
HFE–236ca12 (HG–10)	78522–47–1	$CHF_2OCF_2OCHF_2$	[d] 5,350
HFE–236ea2 (Desflurane)	57041–67–5	$CHF_2OCHFCF_3$	[d] 1,790
HFE–236fa	20193–67–3	$CF_3CH_2OCF_3$	[d] 979
HFE–338mcf2	156053–88–2	$CF_3CF_2OCH_2CF_3$	[d] 929
HFE–338mmz1	26103–08–2	$CHF_2OCH(CF_3)_2$	[d] 2,620
HFE–338pcc13 (HG–01)	188690–78–0	$CHF_2OCF_2CF_2OCHF_2$	[d] 2,910
HFE–43–10pccc (H-Galden 1040x, HG–11)	E1730133	$CHF_2OCF_2OC_2F_4OCHF_2$	[d] 2,820
HCFE–235ca2 (Enflurane)	13838–16–9	CHF_2OCF_2CHFCl	[b] 583

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS, 100-YEAR TIME HORIZON—Continued

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
HCFE–235da2 (Isoflurane)	26675–46–7	$CHF_2OCHClCF_3$	[d] 491
HG–02	205367–61–9	$HF_2C\text{-}(OCF_2CF_2)_2\text{-}OCF_2H$	[b,d] 2,730
HG–03	173350–37–3	$HF_2C\text{-}(OCF_2CF_2)_3\text{-}OCF_2H$	[b,d] 2,850
HG–20	249932–25–0	$HF_2C\text{-}(OCF_2)_2\text{-}OCF_2H$	[b] 5,300
HG–21	249932–26–1	$HF_2C\text{-}OCF_2CF_2OCF_2OCF_2O\text{-}CF_2H$	[b] 3,890
HG–30	188690–77–9	$HF_2C\text{-}(OCF_2)_3\text{-}OCF_2H$	[b] 7,330
1,1,3,3,4,4,6,6,7,7,9,9,10,10,12,12,13,13,15,15-eicosafluoro-2,5,8,11,14-Pentaoxapentadecane.	173350–38–4	$HCF_2O(CF_2CF_2O)_4CF_2H$	[b] 3,630
1,1,2-Trifluoro-2-(trifluoromethoxy)-ethane	84011–06–3	$CHF_2CHFOCF_3$	[b] 1,240
Trifluoro(fluoromethoxy)methane	2261–01–0	CH_2FOCF_3	[b] 751
Saturated HFEs and HCFEs With Three or More Carbon-Hydrogen Bonds			
HFE–143a	421–14–7	CH_3OCF_3	[d] 523
HFE–245cb2	22410–44–2	$CH_3OCF_2CF_3$	[d] 654
HFE–245fa1	84011–15–4	$CHF_2CH_2OCF_3$	[d] 828
HFE–245fa2	1885–48–9	$CHF_2OCH_2CF_3$	[d] 812
HFE–254cb1	425–88–7	$CH_3OCF_2CHF_2$	[d] 301
HFE–263fb2	460–43–5	$CF_3CH_2OCH_3$	[d] 1
HFE–263m1; R–E–143a	690–22–2	$CF_3OCH_2CH_3$	[b] 29
HFE–347mcc3 (HFE–7000)	375–03–1	$CH_3OCF_2CF_2CF_3$	[d] 530
HFE–347mcf2	171182–95–9	$CF_3CF_2OCH_2CHF_2$	[d] 854
HFE–347mmy1	22052–84–2	$CH_3OCF(CF_3)_2$	[d] 363
HFE–347mmz1 (Sevoflurane)	28523–86–6	$(CF_3)_2CHOCH_2F$	[c] 216
HFE–347pcf2	406–78–0	$CHF_2CF_2OCH_2CF_3$	[d] 889
HFE–356mec3	382–34–3	$CH_3OCF_2CHFCF_3$	[d] 387
HFE–356mff2	333–36–8	$CF_3CH_2OCH_2CF_3$	[b] 17
HFE–356mmz1	13171–18–1	$(CF_3)_2CHOCH_3$	[d] 14
HFE–356pcc3	160620–20–2	$CH_3OCF_2CF_2CHF_2$	[d] 413
HFE–356pcf2	50807–77–7	$CHF_2CH_2OCF_2CHF_2$	[d] 719
HFE–356pcf3	35042–99–0	$CHF_2OCH_2CF_2CHF_2$	[d] 446
HFE–365mcf2	22052–81–9	$CF_3CF_2OCH_2CH_3$	[b] 58
HFE–365mcf3	378–16–5	$CF_3CF_2CH_2OCH_3$	[d] 0.99
HFE–374pc2	512–51–6	$CH_3CH_2OCF_2CHF_2$	[d] 627
HFE–449s1 (HFE–7100) Chemical blend	163702–07–6 163702–08–7	$C_4F_9OCH_3$ $(CF_3)_2CFCF_2OCH_3$	[d] 421 ……
HFE–569sf2 (HFE–7200) Chemical blend	163702–05–4 163702–06–5	$C_4F_9OC_2H_5$ $(CF_3)_2CFCF_2OC_2H_5$	[d] 57 ……
HFE–7300	132182–92–4	$(CF_3)_2CFCFOC_2H_5CF_2CF_2CF_3$	[e] 405
HFE–7500	297730–93–9	$n\text{-}C_3F_7CFOC_2H_5CF(CF_3)_2$	[e] 13
HG′-01	73287–23–7	$CH_3OCF_2CF_2OCH_3$	[b] 222
HG′-02	485399–46–0	$CH_3O(CF_2CF_2O)_2CH_3$	[b] 236
HG′-03	485399–48–2	$CH_3O(CF_2CF_2O)_3CH_3$	[b] 221
Difluoro(methoxy)methane	359–15–9	CH_3OCHF_2	[b] 144
2-Chloro-1,1,2-trifluoro-1-methoxyethane	425–87–6	CH_3OCF_2CHFCl	[b] 122
1-Ethoxy-1,1,2,2,3,3,3-heptafluoropropane	22052–86–4	$CF_3CF_2CF_2OCH_2CH_3$	[b] 61
2-Ethoxy-3,3,4,4,5-pentafluorotetrahydro-2,5-bis[1,2,2,2-tetrafluoro-1-(trifluoromethyl)ethyl]-furan.	920979–28–8	$C_{12}H_5F_{19}O_2$	[b] 56
1-Ethoxy-1,1,2,3,3,3-hexafluoropropane	380–34–7	$CF_3CHFCF_2OCH_2CH_3$	[b] 23
Fluoro(methoxy)methane	460–22–0	CH_3OCH_2F	[b] 13
1,1,2,2-Tetrafluoro-3-methoxy-propane; Methyl 2,2,3,3-tetrafluoropropyl ether.	60598–17–6	$CHF_2CF_2CH_2OCH_3$	[b,d] 0.49
1,1,2,2-Tetrafluoro-1-(fluoromethoxy)ethane	37031–31–5	$CH_2FOCF_2CF_2H$	[b] 871
Difluoro(fluoromethoxy)methane	461–63–2	CH_2FOCHF_2	[b] 617
Fluoro(fluoromethoxy)methane	462–51–1	CH_2FOCH_2F	[b] 130
Saturated Chlorofluorocarbons (CFCs)			
E–R316c	3832–15–3	trans-cyc $(\text{-}CClFCF_2CF_2CClF\text{-})$	[e] 4,230
Z–R316c	3934–26–7	cis-cyc $(\text{-}CClFCF_2CF_2CClF\text{-})$	[e] 5,660
Fluorinated Formates			
Trifluoromethyl formate	85358–65–2	$HCOOCF_3$	[b] 588
Perfluoroethyl formate	313064–40–3	$HCOOCF_2CF_3$	[b] 580
1,2,2,2-Tetrafluoroethyl formate	481631–19–0	$HCOOCHFCF_3$	[b] 470
Perfluorobutyl formate	197218–56–7	$HCOOCF_2CF_2CF_2CF_3$	[b] 392
Perfluoropropyl formate	271257–42–2	$HCOOCF_2CF_2CF_3$	[b] 376
1,1,1,3,3,3-Hexafluoropropan-2-yl formate	856766–70–6	$HCOOCH(CF_3)_2$	[b] 333
2,2,2-Trifluoroethyl formate	32042–38–9	$HCOOCH_2CF_3$	[b] 33

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS, 100-YEAR TIME HORIZON—Continued

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
3,3,3-Trifluoropropyl formate	1344118–09–7	$HCOOCH_2CH_2CF_3$	[b] 17
Fluorinated Acetates			
Methyl 2,2,2-trifluoroacetate	431–47–0	CF_3COOCH_3	[b] 52
1,1-Difluoroethyl 2,2,2-trifluoroacetate	1344118–13–3	$CF_3COOCF_2CH_3$	[b] 31
Difluoromethyl 2,2,2-trifluoroacetate	2024–86–4	$CF_3COOCHF_2$	[b] 27
2,2,2-Trifluoroethyl 2,2,2-trifluoroacetate	407–38–5	$CF_3COOCH_2CF_3$	[b] 7
Methyl 2,2-difluoroacetate	433–53–4	HCF_2COOCH_3	[b] 3
Perfluoroethyl acetate	343269–97–6	$CH_3COOCF_2CF_3$	[b,d] 2
Trifluoromethyl acetate	74123–20–9	CH_3COOCF_3	[b,d] 2
Perfluoropropyl acetate	1344118–10–0	$CH_3COOCF_2CF_2CF_3$	[b,d] 2
Perfluorobutyl acetate	209597–28–4	$CH_3COOCF_2CF_2CF_2CF_3$	[b,d] 2
Ethyl 2,2,2-trifluoroacetate	383–63–1	$CF_3COOCH_2CH_3$	[b,d] 1
Carbonofluoridates			
Methyl carbonofluoridate	1538–06–3	$FCOOCH_3$	[b] 95
1,1-Difluoroethyl carbonofluoridate	1344118–11–1	$FCOOCF_2CH_3$	[b] 27
Fluorinated Alcohols Other Than Fluorotelomer Alcohols			
Bis(trifluoromethyl)-methanol	920–66–1	$(CF_3)_2CHOH$	[d] 182
2,2,3,3,4,4,5,5-Octafluorocyclopentanol	16621–87–7	cyc $(-(CF_2)_4CH(OH)-)$	[d] 13
2,2,3,3,3-Pentafluoropropanol	422–05–9	$CF_3CF_2CH_2OH$	[d] 19
2,2,3,3,4,4,4-Heptafluorobutan-1-ol	375–01–9	C_3F_7CH2OH	[b,d] 34
2,2,2-Trifluoroethanol	75–89–8	CF_3CH_2OH	[b] 20
2,2,3,4,4,4-Hexafluoro-1-butanol	382–31–0	$CF_3CHFCF_2CH_2OH$	[b] 17
2,2,3,3-Tetrafluoro-1-propanol	76–37–9	$CHF_2CF_2CH_2OH$	[b] 13
2,2-Difluoroethanol	359–13–7	CHF_2CH2OH	[b] 3
2-Fluoroethanol	371–62–0	CH_2FCH_2OH	[b] 1.1
4,4,4-Trifluorobutan-1-ol	461–18–7	$CF_3(CH_2)_2CH_2OH$	[b] 0.05
Non-Cyclic, Unsaturated Perfluorocarbons (PFCs)			
PFC–1114; TFE	116–14–3	$CF_2 = CF_2$; C_2F_4	[b] 0.004
PFC–1216; Dyneon HFP	116–15–4	C_3F_6; $CF_3CF = CF_2$	[b] 0.05
Perfluorobut-2-ene	360–89–4	$CF_3CF = CFCF_3$	[b] 1.82
Perfluorobut-1-ene	357–26–6	$CF_3CF_2CF = CF_2$	[b] 0.10
Perfluorobuta-1,3-diene	685–63–2	$CF_2 = CFCF = CF_2$	[b] 0.003
Non-Cyclic, Unsaturated Hydrofluorocarbons (HFCs) and Hydrochlorofluorocarbons (HCFCs)			
HFC–1132a; VF2	75–38–7	$C_2H_2F_2$, $CF_2 = CH_2$	[b] 0.04
HFC–1141; VF	75–02–5	C_2H_3F, $CH_2 = CHF$	[b] 0.02
(E)-HFC–1225ye	5595–10–8	$CF_3CF = CHF(E)$	[b] 0.06
(Z)-HFC–1225ye	5528–43–8	$CF_3CF = CHF(Z)$	[b] 0.22
Solstice 1233zd(E)	102687–65–0	$C_3H_2ClF_3$; $CHCl = CHCF_3$	[b] 1.34
HCFO–1233zd(Z)	99728–16–2	(Z)-$CF_3CH = CHCl$	[e] 0.45
HFC–1234yf; HFO–1234yf	754–12–1	$C_3H_2F_4$; $CF_3CF = CH_2$	[b] 0.31
HFC–1234ze(E)	1645–83–6	$C_3H_2F_4$; trans-$CF_3CH = CHF$	[b] 0.97
HFC–1234ze(Z)	29118–25–0	$C_3H_2F_4$; cis-$CF_3CH = CHF$; $CF_3CH = CHF$	[b] 0.29
HFC–1243zf; TFP	677–21–4	$C_3H_3F_3$, $CF_3CH = CH_2$	[b] 0.12
(Z)-HFC–1336	692–49–9	$CF_3CH = CHCF_3(Z)$	[b] 1.58
HFO–1336mzz(E)	66711–86–2	(E)-$CF_3CH = CHCF_3$	[e] 18
HFC–1345zfc	374–27–6	$C_2F_5CH = CH_2$	[b] 0.09
HFO–1123	359–11–5	$CHF=CF_2$	[e] 0.005
HFO–1438ezy(E)	14149–41–8	(E)-$(CF_3)_2CFCH = CHF$	[e] 8.2
HFO–1447fz	355–08–8	$CF_3(CF_2)_2CH = CH_2$	[e] 0.24
Capstone 42–U	19430–93–4	$C_6H_3F_9$, $CF_3(CF_2)_3CH = CH_2$	[b] 0.16
Capstone 62–U	25291–17–2	$C_8H_3F_{13}$, $CF_3(CF_2)_5CH = CH_2$	[b] 0.11
Capstone 82–U	21652–58–4	$C_{10}H_3F_{17}$, $CF_3(CF_2)_7CH = CH_2$	[b] 0.09
(e)-1-chloro-2-fluoroethene	460–16–2	(E)-$CHCl = CHF$	[e] 0.004
3,3,3-trifluoro-2-(trifluoromethyl)prop-1-ene	382–10–5	$(CF_3)_2C = CH_2$	[e] 0.38
Non-Cyclic, Unsaturated CFCs			
CFC–1112	598–88–9	$CClF=CClF$	[e] 0.13
CFC–1112a	79–35–6	$CCl_2=CF_2$	[e] 0.021

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS, 100-YEAR TIME HORIZON—Continued

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Non-Cyclic, Unsaturated Halogenated Ethers			
PMVE; HFE–216	1187–93–5	$CF_3OCF = CF_2$	[b] 0.17
Fluoroxene	406–90–6	$CF_3CH_2OCH = CH_2$	[b] 0.05
Methyl-perfluoroheptene-ethers	N/A	$CH_3OC_7F_{13}$	[e] 15
Non-Cyclic, Unsaturated Halogenated Esters			
Ethenyl 2,2,2-trifluoroacetate	433–28–3	$CF_3COOCH{=}CH_2$	[e] 0.008
Prop-2-enyl 2,2,2-trifluoroacetate	383–67–5	$CF_3COOCH_2CH{=}CH_2$	[e] 0.007
Cyclic, Unsaturated HFCs and PFCs			
PFC C–1418	559–40–0	$c\text{-}C_5F_8$	[d] 2
Hexafluorocyclobutene	697–11–0	$cyc\ (\text{-}CF{=}CFCF_2CF_2\text{-})$	[e] 126
1,3,3,4,4,5,5-heptafluorocyclopentene	1892–03–1	$cyc\ (\text{-}CF_2CF_2CF_2CF{=}CH\text{-})$	[e] 45
1,3,3,4,4-pentafluorocyclobutene	374–31–2	$cyc\ (\text{-}CH{=}CFCF_2CF_2\text{-})$	[e] 92
3,3,4,4-tetrafluorocyclobutene	2714–38–7	$cyc\ (\text{-}CH{=}CHCF_2CF_2\text{-})$	[e] 26
Fluorinated Aldehydes			
3,3,3-Trifluoro-propanal	460–40–2	CF_3CH_2CHO	[b] 0.01
Fluorinated Ketones			
Novec 1230 (perfluoro (2-methyl-3-pentanone))	756–13–8	$CF_3CF_2C(O)CF\ (CF3)_2$	[b] 0.1
1,1,1-trifluoropropan-2-one	421–50–1	CF_3COCH_3	[e] 0.09
1,1,1-trifluorobutan-2-one	381–88–4	$CF_3COCH_2CH_3$	[e] 0.095
Fluorotelomer Alcohols			
3,3,4,4,5,5,6,6,7,7,7-Undecafluoroheptan-1-ol	185689–57–0	$CF_3(CF_2)_4CH_2CH_2OH$	[b] 0.43
3,3,3-Trifluoropropan-1-ol	2240–88–2	$CF_3CH_2CH_2OH$	[b] 0.35
3,3,4,4,5,5,6,6,7,7,8,8,9,9,9-Pentadecafluorononan-1-ol	755–02–2	$CF_3(CF_2)_6CH_2CH_2OH$	[b] 0.33
3,3,4,4,5,5,6,6,7,7,8,8,9,9,10,10,11,11,11-Nonadecafluoroundecan-1-ol.	87017–97–8	$CF_3(CF_2)_8CH_2CH_2OH$	[b] 0.19
Fluorinated GHGs With Carbon-Iodine Bond(s)			
Trifluoroiodomethane	2314–97–8	CF_3I	[b] 0.4
Remaining Fluorinated GHGs with Chemical-Specific GWPs			
Dibromodifluoromethane (Halon 1202)	75–61–6	CBr_2F_2	[b] 231
2-Bromo-2-chloro-1,1,1-trifluoroethane (Halon-2311/Halothane).	151–67–7	$CHBrClCF_3$	[b] 41
Heptafluoroisobutyronitrile	42532–60–5	$(CF_3)_2CFCN$	[e] 2,750
Carbonyl fluoride	353–50–4	COF_2	[e] 0.14

Fluorinated GHG group[f]	Global warming potential (100 yr.)
Default GWPs for Compounds for Which Chemical-Specific GWPs Are Not Listed Above	
Fully fluorinated GHGs[g]	9,200
Saturated hydrofluorocarbons (HFCs) with 2 or fewer carbon-hydrogen bonds[g]	3,000
Saturated HFCs with 3 or more carbon-hydrogen bonds[g]	840
Saturated hydrofluoroethers (HFEs) and hydrochlorofluoroethers (HCFEs) with 1 carbon-hydrogen bond[g]	6,600
Saturated HFEs and HCFEs with 2 carbon-hydrogen bonds[g]	2,900
Saturated HFEs and HCFEs with 3 or more carbon-hydrogen bonds[g]	320
Saturated chlorofluorocarbons (CFCs)[g]	4,900
Fluorinated formates	350
Cyclic forms of the following: unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated CFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated bromofluorocarbons (BFCs), unsaturated bromochlorofluorocarbons (BCFCs), unsaturated hydrobromofluorocarbons (HBFCs), unsaturated hydrobromochlorofluorocarbons (HBCFCs), unsaturated halogenated ethers, and unsaturated halogenated esters[g]	58
Fluorinated acetates, carbonofluoridates, and fluorinated alcohols other than fluorotelomer alcohols[g]	25

Fluorinated GHG group[f]	Global warming potential (100 yr.)
Fluorinated aldehydes, fluorinated ketones, and non-cyclic forms of the following: unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated CFCs, unsaturated HCFCs, unsaturated BFCs, unsaturated BCFCs, unsaturated HBFCs, unsaturated HBCFCs, unsaturated halogenated ethers and unsaturated halogenated esters[g]	1
Fluorotelomer alcohols[g]	1
Fluorinated GHGs with carbon-iodine bond(s)[g]	1
Other fluorinated GHGs[g]	1,800

[a] The GWP for this compound was updated in the final rule published on November 29, 2013 [78 FR 71904] and effective on January 1, 2014.

[b] This compound was added to table A–1 in the final rule published on December 11, 2014, and effective on January 1, 2015.

[c] The GWP for this compound was updated in the final rule published on December 11, 2014, and effective on January 1, 2015.

[d] The GWP for this compound was updated in the final rule published on April 25, 2024 and effective on January 1, 2025.

[e] The GWP for this compound was added to table A–1 in the final rule published on April 25, 2024 and effective on January 1, 2025.

[f] For electronics manufacturing (as defined in § 98.90), the term "fluorinated GHGs" in the definition of each fluorinated GHG group in § 98.6 shall include fluorinated heat transfer fluids (as defined in § 98.6), whether or not they are also fluorinated GHGs.

[g] The GWP for this fluorinated GHG group was updated in the final rule published on April 25, 2024 and effective on January 1, 2025.

■ 10. Revise and republish table A–3 to subpart A to read as follows:

TABLE A–3 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(1)

- Source Categories[a] Applicable in Reporting Year 2010 and Future Years:
  - Electricity generation units that report CO_2 mass emissions year round through 40 CFR part 75 (subpart D).
  - Adipic acid production (subpart E of this part).
  - Aluminum production (subpart F of this part).
  - Ammonia manufacturing (subpart G of this part).
  - Cement production (subpart H of this part).
  - HCFC–22 production (subpart O of this part).
  - 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 (subpart O of this part).
  - Lime manufacturing (subpart S of this part).
  - Nitric acid production (subpart V of this part).
  - Petrochemical production (subpart X of this part).
  - Petroleum refineries (subpart Y of this part).
  - Phosphoric acid production (subpart Z of this part).
  - Silicon carbide production (subpart BB of this part).
  - Soda ash production (subpart CC of this part).
  - Titanium dioxide production (subpart EE of this part).
  - Municipal solid waste landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to subpart HH of this part.
  - Manure management systems with combined CH_4 and N_2O emissions in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to subpart JJ of this part.
- Additional Source Categories[a] Applicable in Reporting Year 2011 and Future Years:
  - Electrical transmission and distribution equipment use at facilities where the total estimated emissions from fluorinated GHGs, as determined under § 98.301 (subpart DD of this part), are equivalent to 25,000 metric tons CO_2e or more per year.
  - Underground coal mines liberating 36,500,000 actual cubic feet of CH_4 or more per year (subpart FF of this part).
  - Geologic sequestration of carbon dioxide (subpart RR of this part).
  - Injection of carbon dioxide (subpart UU of this part).
- Additional Source Categories[a] Applicable in Reporting Year 2025 and Future Years:
  - Geologic sequestration of carbon dioxide with enhanced oil recovery using ISO 27916 (subpart VV of this part).
  - Coke calciners (subpart WW of this part).
  - Calcium carbide production (subpart XX of this part).
  - Caprolactam, glyoxal, and glyoxylic acid production (subpart YY of this part).

[a] Source categories are defined in each applicable subpart of this part.

■ 11. Revise and republish table A–4 to subpart A to read as follows:

TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)

- Source Categories[a] Applicable in Reporting Year 2010 and Future Years:
  - Ferroalloy production (subpart K of this part).
  - Glass production (subpart N of this part).
  - Hydrogen production (subpart P of this part).
  - Iron and steel production (subpart Q of this part).
  - Lead production (subpart R of this part).
  - Pulp and paper manufacturing (subpart AA of this part).
  - Zinc production (subpart GG of this part).
- Additional Source Categories[a] Applicable in Reporting Year 2011 and Future Years:

TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)—Continued

Electronics manufacturing (subpart I of this part).
Fluorinated gas production (subpart L of this part).
Magnesium production (subpart T of this part).
Petroleum and Natural Gas Systems (subpart W of this part).
Industrial wastewater treatment (subpart II of this part).
Electrical transmission and distribution equipment manufacture or refurbishment, as determined under § 98.451 (subpart SS of this part).
Industrial waste landfills (subpart TT of this part).
Additional Source Categories[a] Applicable in Reporting Year 2025 and Future Years:
Ceramics manufacturing facilities, as determined under § 98.520 (subpart ZZ of this part).

[a] Source categories are defined in each applicable subpart.

Subpart C—General Stationary Fuel Combustion Sources

■ 12. Amend § 98.33 by:
■ a. Revising and republishing paragraph (a)(3)(iii);
■ b. Revising paragraph (b)(1)(vii);
■ c. Revising parameter "EF" of equation C–10 in paragraph (c)(4) introductory text;
■ d. Revising and republishing paragraph (c)(6);
■ e. Revising parameter "R" of equation C–11 in paragraph (d)(1); and
■ f. Revising the introductory text of paragraphs (e), (e)(1) and (3), and paragraph (e)(3)(iv).

The revisions read as follows:

§ 98.33 Calculating GHG emissions.

* * * * *

(a) * * *

(3) * * *

(iii) For a gaseous fuel, use equation C–5 to this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * \frac{\text{MW}}{\text{MVC}} * 0.001$$

(Eq. C–5)

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i). Fuel billing meters may be used for this purpose.
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the procedures specified in paragraphs (a)(3)(iii)(A)(*1*) and (*2*) of this section.
MW = Annual average molecular weight of the gaseous fuel (kg per kg-mole). The annual average molecular weight shall be determined using the procedures specified in paragraphs (a)(3)(iii)(B)(*1*) and (*2*) of this section.
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

(A) The minimum required sampling frequency for determining the annual average carbon content (*e.g.,* monthly, quarterly, semi-annually, or by lot) is specified in § 98.34. The method for computing the annual average carbon content for equation C–5 to this section is a function of unit size and how frequently you perform or receive from the fuel supplier the results of fuel sampling for carbon content. The methods are specified in paragraphs (a)(3)(iii)(A)(*1*) and (*2*) of this section, as applicable.

(*1*) If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average carbon content for equation C–5 shall be calculated using equation C–5A to this section. If multiple carbon content determinations are made in any month, average the values for the month arithmetically.

$$(\text{CC})_{\text{annual}} = \frac{\sum_{i=1}^{n} (\text{CC})_i * (\text{Fuel})_i * (\text{MW})_i / \text{MWC}}{\sum_{i=1}^{n} (\text{Fuel})_i * (\text{MW})_i / \text{MVC}}$$

(Eq. C–5A)

Where:

$(CC)_{annual}$ = Weighted annual average carbon content of the fuel (kg C per kg of fuel).
$(CC)_i$ = Measured carbon content of the fuel, for sample period "i" (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg C per kg of fuel).
$(Fuel)_i$ = Volume of the fuel (scf) combusted during the sample period "i" (*e.g.,* monthly, quarterly, semi-annually, or by lot) from company records.
$(MW)_i$ = Measured molecular weight of the fuel, for sample period "i" (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg per kg-mole).
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6. Use 849.5 scf per kg-mole if you select 68 °F as standard temperature and 836.6

scf per kg-mole if you select 60 °F as standard temperature.
n = Number of sample periods in the year.

(*2*) If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the carbon content sampling frequency, the annual average carbon content for equation C–5 shall either be computed according to paragraph (a)(3)(iii)(A)(*1*) of this section or as the arithmetic average carbon content for all values for the year (including valid samples and substitute data values under § 98.35).

(B) The minimum required sampling frequency for determining the annual average molecular weight (*e.g.,* monthly, quarterly, semi-annually, or by lot) is specified in § 98.34. The method for computing the annual average molecular weight for equation C–5 is a function of unit size and how frequently you perform or receive from the fuel supplier the results of fuel sampling for molecular weight. The methods are specified in paragraphs (a)(3)(iii)(B)(*1*) and (*2*) of this section, as applicable.

(*1*) If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average molecular weight for equation C–5 shall be calculated using equation C–5B to this section. If multiple molecular weight determinations are made in any month, average the values for the month arithmetically.

$$(\mathrm{MW})_{\mathrm{annual}} = \frac{\sum_{i=1}^{n} (\mathrm{MW})_i * (\mathrm{Fuel})_i/\mathrm{MVC}}{\sum_{i=1}^{n} (\mathrm{Fuel})_i/\mathrm{MVC}}$$

(Eq. C–5B)

Where:
$(MW)_{annual}$ = Weighted annual average molecular weight of the fuel (kg per kg-mole).
$(MW)_i$ = Measured molecular weight of the fuel, for sample period ‘‘i’’ (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg per kg-mole).
$(Fuel)_i$ = Volume of the fuel (scf) combusted during the sample period ‘‘i’’ (*e.g.,* monthly, quarterly, semi-annually, or by lot) from company records.
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6. Use 849.5 scf per kg-mole if you select 68 °F as standard temperature and 836.6 scf per kg-mole if you select 60 °F as standard temperature.
n = Number of sample periods in the year.

(*2*) If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the molecular weight sampling frequency, the annual average molecular weight for equation C–5 shall either be computed according to paragraph (a)(3)(iii)(B)(*1*) of this section or as the arithmetic average molecular weight for all values for the year (including valid samples and substitute data values under § 98.35).

* * * * *

(b) * * *

(1) * * *

(vii) May be used for the combustion of MSW and/or tires in a unit, provided that no more than 10 percent of the unit's annual heat input is derived from those fuels, combined.

* * * * *

(c) * * *

(4) * * *

EF = Fuel-specific emission factor for CH_4 or N_2O, from table C–2 to this subpart (kg CH_4 or N_2O per mmBtu).

* * * * *

(6) Calculate the annual CH_4 and N_2O mass emissions from the combustion of blended fuels as follows:

(i) If the mass, volume, or heat input of each component fuel in the blend is determined before the fuels are mixed and combusted, calculate and report CH_4 and N_2O emissions separately for each component fuel, using the applicable procedures in this paragraph (c).

(ii) If the mass, volume, or heat input of each component fuel in the blend is not determined before the fuels are mixed and combusted, a reasonable estimate of the percentage composition of the blend, based on best available information, is required. Perform the following calculations for each component fuel ‘‘i’’ that is listed in table C–2 to this subpart:

(A) Multiply (% Fuel)i, the estimated mass, volume, or heat input percentage of component fuel ‘‘i’’ (expressed as a decimal fraction), by the total annual mass, volume, or heat input of the blended fuel combusted during the reporting year, to obtain an estimate of the annual value for component ‘‘i’’;

(B) [Reserved]

(C) Calculate the annual CH_4 and N_2O emissions from component ‘‘i’’, using equation C–8 (fuel mass or volume) to this section, C–8a (fuel heat input) to this section, C–8b (fuel heat input) to this section, C–9a (fuel mass or volume) to this section, or C–10 (fuel heat input) to this section, as applicable;

(D) Sum the annual CH_4 emissions across all component fuels to obtain the annual CH_4 emissions for the blend. Similarly sum the annual N_2O emissions across all component fuels to obtain the annual N_2O emissions for the blend. Report these annual emissions totals.

(d) * * *

(1) * * *

R = The number of moles of CO_2 released per mole of sorbent used (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2).

* * * * *

(e) *Biogenic CO_2 emissions from combustion of biomass with other fuels.* Use the applicable procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels (*i.e.,* either co-fired or blended fuels). Separate reporting of biogenic CO_2 emissions from the combined combustion of biomass and fossil fuels is required for those biomass fuels listed in table C–1 to this subpart, MSW, and tires. In addition, when a biomass fuel that is not listed in table C–1 to this subpart is combusted in a unit that has a maximum rated heat input greater than 250 mmBtu/hr, if the biomass fuel accounts for 10% or more of the annual heat input to the unit, and if the unit does not use CEMS to quantify its annual CO_2 mass emissions, then, pursuant to paragraph (b)(3)(iii) of this section, Tier 3 must be used to determine the carbon content of the biomass fuel and to calculate the biogenic CO_2 emissions from combustion of the fuel. Notwithstanding these requirements, in accordance with § 98.3(c)(12), separate reporting of biogenic CO_2 emissions is optional for the 2010 reporting year for units subject to subpart D of this part and for units that use the CO_2 mass emissions calculation methodologies in part 75 of this chapter, pursuant to paragraph (a)(5) of this section. However, if the owner or operator opts to report biogenic CO_2 emissions separately for these units, the appropriate method(s) in this paragraph (e) shall be used.

(1) You may use equation C–1 to this section to calculate the annual CO_2 mass emissions from the combustion of the biomass fuels listed in table C–1 to this subpart, in a unit of any size, including units equipped with a CO_2 CEMS, except when the use of Tier 2 is required as specified in paragraph (b)(1)(iv) of this section. Determine the quantity of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate, and document the selected procedures in the Monitoring Plan under § 98.3(g):

* * * * *

(3) You must use the procedures in paragraphs (e)(3)(i) through (iii) of this section to determine the annual biogenic CO_2 emissions from the combustion of MSW, except as otherwise provided in paragraph (e)(3)(iv) of this section. These procedures also may be used for any unit that co-fires biomass and fossil fuels, including units equipped with a CO_2 CEMS.

* * * * *

(iv) In lieu of following the procedures in paragraphs (e)(3)(i) through (iii) of this section, the procedures of this paragraph (e)(3)(iv) may be used for the combustion of tires regardless of the percent of the annual heat input provided by tires. The calculation procedure in this paragraph (e)(3)(iv) may be used for the combustion of MSW if the combustion of MSW provides no more than 10 percent of the annual heat input to the unit or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW.

(A) Calculate the total annual CO_2 emissions from combustion of MSW and/or tires in the unit, using the applicable methodology in paragraphs (a)(1) through (3) of this section for units using Tier 1, Tier 2, or Tier 3; otherwise use the Tier 1 calculation methodology in paragraph (a)(1) of this section for units using either the Tier 4 or Alternative Part 75 calculation methodologies to calculate total CO_2 emissions.

(B) Multiply the result from paragraph (e)(3)(iv)(A) of this section by the appropriate default factor to determine the annual biogenic CO_2 emissions, in metric tons. For MSW, use a default factor of 0.60 and for tires, use a default factor of 0.24.

* * * * *

■ 13. Amend § 98.34 by revising paragraphs (c)(6), (d) and (e) to read as follows:

§ 98.34 Monitoring and QA/QC requirements.

* * * * *

(c) * * *

(6) For applications where CO_2 concentrations in process and/or combustion flue gasses are lower or higher than the typical CO_2 span value for coal-based fuels (*e.g.,* 20 percent CO_2 for a coal fired boiler), cylinder gas audits of the CO_2 monitor under appendix F to part 60 of this chapter may be performed at 40–60 percent and 80–100 percent of CO_2 span, in lieu of the prescribed calibration levels of 5–8 percent and 10–14 percent CO_2 by volume.

* * * * *

(d) Except as otherwise provided in § 98.33(e)(3)(iv), when municipal solid waste (MSW) is either the primary fuel combusted in a unit or the only fuel with a biogenic component combusted in the unit, determine the biogenic portion of the CO_2 emissions using ASTM D6866–16 and ASTM D7459–08 (both incorporated by reference, see § 98.7). Perform the ASTM D7459–08 sampling and the ASTM D6866–16 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions for at least 24 total (not necessarily consecutive) hours, or longer if the facility deems it necessary to obtain a representative sample. Notwithstanding this requirement, if the types of fuels combusted and their relative proportions are consistent throughout the year, the minimum required sampling time may be reduced to 8 hours if at least two 8-hour samples and one 24-hour sample are collected under normal operating conditions, and arithmetic average of the biogenic fraction of the flue gas from the 8-hour samples (expressed as a decimal) is within ±5 percent of the biogenic fraction from the 24-hour test. There must be no overlapping of the 8-hour and 24-hour test periods. Document the results of the demonstration in the unit's monitoring plan. If the types of fuels and their relative proportions are not consistent throughout the year, an optional sampling approach that facilities may wish to consider to obtain a more representative sample is to collect an integrated sample by extracting a small amount of flue gas (*e.g.,* 1 to 5 cc) in each unit operating hour during the quarter. Separate the total annual CO_2 emissions into the biogenic and non-biogenic fractions using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (*e.g.,* 0.30, if 30 percent of the CO_2 is biogenic). When MSW is the primary fuel for multiple units at the facility, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, *e.g.,* tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866–16 and ASTM D7459–08 (both incorporated by reference, see § 98.7) may be used to determine the biogenic portion of the CO_2 emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. If multiple units at the facility are fed from a common fuel source, testing at only one of the units is sufficient.

* * * * *

■ 14. Amend § 98.36 by revising paragraphs (c)(1)(vi), (c)(3)(vi), (e)(2)(ii)(C) and (e)(2)(xi) to read as follows:

§ 98.36 Data reporting requirements.

* * * * *

(c) * * *

(1) * * *

(vi) Annual CO_2 mass emissions and annual CH_4, and N_2O mass emissions, aggregated for each type of fuel combusted in the group of units during the report year, expressed in metric tons of each gas and in metric tons of CO_2e. If any of the units burn biomass, report also the annual CO_2 emissions from combustion of all biomass fuels combined, expressed in metric tons.

* * * * *

(3) * * *

(vi) If any of the units burns biomass, the annual CO_2 emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

* * * * *

(e) * * *

(2) * * *

(ii) * * *

(C) The annual average, and, where applicable, monthly high heat values used in the CO_2 emissions calculations for each type of fuel combusted during the reporting year, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Report an HHV value for each calendar month in which HHV determination is required. If multiple values are obtained in a given month, report the arithmetic average value for the month.

* * * * *

(xi) When ASTM methods D7459–08 and D6866–16 (both incorporated by reference, see § 98.7) are used in accordance with § 98.34(e) to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic fuels (or partly-biogenic fuels, including tires) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (*e.g.,* if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).

* * * * *

■ 15. Amend § 98.37 by revising and republishing paragraph (b) to read as follows:

§ 98.37 Records that must be retained.

* * * * *

(b) The applicable verification software records as identified in this paragraph (b). For each stationary fuel combustion source that elects to use the verification software specified in § 98.5(b) rather than report data specified in paragraphs (b)(9)(iii), (c)(2)(ix), (e)(2)(i), (e)(2)(ii)(A), (C), and (D), (e)(2)(iv)(A), (C), and (F), and (e)(2)(ix)(D) through (F) of this section, you must keep a record of the file generated by the verification software for the applicable data specified in paragraphs (b)(1) through (37) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (b)(1) through (37) of this section.

(1) Mass of each solid fuel combusted (tons/year) (equation C–1 to § 98.33).

(2) Volume of each liquid fuel combusted (gallons/year) (equation C–1 to § 98.33).

(3) Volume of each gaseous fuel combusted (scf/year) (equation C–1 to § 98.33).

(4) Annual natural gas usage (therms/year) (equation C–1a to § 98.33).

(5) Annual natural gas usage (mmBtu/year) (equation C–1b to § 98.33).

(6) Mass of each solid fuel combusted (tons/year) (equation C–2a to § 98.33).

(7) Volume of each liquid fuel combusted (gallons/year) (equation C–2a to § 98.33).

(8) Volume of each gaseous fuel combusted (scf/year) (equation C–2a to § 98.33).

(9) Measured high heat value of each solid fuel, for month (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per ton) (equation C–2b to § 98.33). Annual average HHV of each solid fuel (mmBtu per ton) (equation C–2a to § 98.33).

(10) Measured high heat value of each liquid fuel, for month (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per gallons) (equation C–2b to § 98.33). Annual average HHV of each liquid fuel (mmBtu per gallons) (equation C–2a to § 98.33).

(11) Measured high heat value of each gaseous fuel, for month (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per scf) (equation C–2b to § 98.33). Annual average HHV of each gaseous fuel (mmBtu per scf) (equation C–2a to § 98.33).

(12) Mass of each solid fuel combusted during month (tons) (equation C–2b to § 98.33).

(13) Volume of each liquid fuel combusted during month (gallons) (equation C–2b to § 98.33).

(14) Volume of each gaseous fuel combusted during month (scf) (equation C–2b, equation C–5A, equation C–5B to § 98.33).

(15) Total mass of steam generated by municipal solid waste or each solid fuel combustion during the reporting year (pounds steam) (equation C–2c to § 98.33).

(16) Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (MMBtu/pounds steam) (equation C–2c to § 98.33).

(17) Annual mass of each solid fuel combusted (short tons/year) (equation C–3 to § 98.33).

(18) Annual average carbon content of each solid fuel (percent by weight, expressed as a decimal fraction) (equation C–3 to § 98.33). Where applicable, monthly carbon content of each solid fuel (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (percent by weight, expressed as a decimal fraction) (equation C–2b to § 98.33—see the definition of ‘‘CC’’ in equation C–3 to § 98.33).

(19) Annual volume of each liquid fuel combusted (gallons/year) (equation C–4 to § 98.33).

(20) Annual average carbon content of each liquid fuel (kg C per gallon of fuel) (equation C–4 to § 98.33). Where applicable, monthly carbon content of each liquid fuel (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg C per gallon of fuel) (equation C–2b to § 98.33—see the definition of ‘‘CC’’ in equation C–3 to § 98.33).

(21) Annual volume of each gaseous fuel combusted (scf/year) (equation C–5 to § 98.33).

(22) Annual average carbon content of each gaseous fuel (kg C per kg of fuel) (equation C–5 to § 98.33). Where applicable, monthly carbon content of each gaseous (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg C per kg of fuel) (equation C–5A to § 98.33).

(23) Annual average molecular weight of each gaseous fuel (kg/kg-mole) (equation C–5 to § 98.33). Where applicable, monthly molecular weight of each gaseous (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (kg/kg-mole) (equation C–5B to § 98.33).

(24) Molar volume conversion factor at standard conditions, as defined in § 98.6 (scf per kg-mole) (equation C–5 to § 98.33).

(25) Identify for each fuel if you will use the default high heat value from table C–1 to this subpart, or actual high heat value data (equation C–8 to § 98.33).

(26) High heat value of each solid fuel (mmBtu/tons) (equation C–8 to § 98.33).

(27) High heat value of each liquid fuel (mmBtu/gallon) (equation C–8 to § 98.33).

(28) High heat value of each gaseous fuel (mmBtu/scf) (equation C–8 to § 98.33).

(29) Cumulative annual heat input from combustion of each fuel (mmBtu) (equation C–10 to § 98.33).

(30) Total quantity of each solid fossil fuel combusted in the reporting year, as defined in § 98.6 (pounds) (equation C–13 to § 98.33).

(31) Total quantity of each liquid fossil fuel combusted in the reporting year, as defined in § 98.6 (gallons) (equation C–13 to § 98.33).

(32) Total quantity of each gaseous fossil fuel combusted in the reporting year, as defined in § 98.6 (scf) (equation C–13 to § 98.33).

(33) High heat value of the each solid fossil fuel (Btu/lb) (equation C–13 to § 98.33).

(34) High heat value of the each liquid fossil fuel (Btu/gallons) (equation C–13 to § 98.33).

(35) High heat value of the each gaseous fossil fuel (Btu/scf) (equation C–13 to § 98.33).

(36) Fuel-specific carbon based F-factor per fuel (scf CO_2/mmBtu) (equation C–13 to § 98.33).

(37) Moisture content used to calculate the wood and wood residuals wet basis HHV (percent), if applicable (equations C–1 and C–8 to § 98.33).

Subpart G—Ammonia Manufacturing

■ 16. Amend § 98.72 by revising paragraph (a) to read as follows:

§ 98.72 GHGs to report.

* * * * *

(a) CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing unit following the requirements of this subpart.

* * * * *

■ 17. Amend § 98.73 by revising the introductory text and paragraph (b) to read as follows:

§ 98.73 Calculating GHG emissions.

You must calculate and report the annual CO_2 process emissions from each ammonia manufacturing unit using the procedures in either paragraph (a) or (b) of this section.

* * * * *

(b) Calculate and report under this subpart process CO_2 emissions using the procedures in paragraphs (b)(1) through (4) of this section, as applicable.

(1) *Gaseous feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from gaseous feedstock according to equation G–1 to this section:

$$CO_{2,G} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}\right) * 0.001 \qquad \text{(Eq. G–1)}$$

Where:

$CO_{2,G}$ = Annual CO_2 emissions arising from gaseous feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the gaseous feedstock used in month n (scf of feedstock).

CC_n = Carbon content of the gaseous feedstock, for month n (kg C per kg of feedstock), determined according to § 98.74(c).

MW = Molecular weight of the gaseous feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

n = Number of month.

(2) *Liquid feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to equation G–2 to this section:

$$CO_{2,L} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n\right) * 0.001 \qquad \text{(Eq. G–2)}$$

Where:

$CO_{2,L}$ = Annual CO_2 emissions arising from liquid feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the liquid feedstock used in month n (gallons of feedstock).

CC_n = Carbon content of the liquid feedstock, for month n (kg C per gallon of feedstock) determined according to § 98.74(c).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

n = Number of month.

(3) *Solid feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to equation G–3 to this section:

$$CO_{2,S} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n\right) * 0.001 \qquad \text{(Eq. G–3)}$$

Where:

$CO_{2,S}$ = Annual CO_2 emissions arising from solid feedstock consumption (metric tons).

$Fdstk_n$ = Mass of the solid feedstock used in month n (kg of feedstock).

CC_n = Carbon content of the solid feedstock, for month n (kg C per kg of feedstock), determined according to § 98.74(c).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

n = Number of month.

(4) *CO_2 process emissions.* You must calculate the annual CO_2 process emissions at each ammonia manufacturing unit according to equation G–4 to this section:

$$CO_2 = \sum_{p=1}^{3} CO_{2,p} \qquad \text{(Eq. G–4)}$$

Where:

CO_2 = Annual CO_2 process emissions from each ammonia manufacturing unit (metric tons).

$CO_{2,p}$ = Annual CO_2 process emissions arising from feedstock consumption based on feedstock type "p" (metric tons/yr) as calculated in paragraphs (b)(1) through (3) of this section.

p = Index for feedstock type; 1 indicates gaseous feedstock; 2 indicates liquid feedstock; and 3 indicates solid feedstock.

* * * * *

■ 18. Amend § 98.76 by revising the introductory text and paragraphs (b)(1) and (13) and adding paragraph (b)(16) to read as follows:

§ 98.76 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable for each ammonia manufacturing unit.

* * * * *

(b) * * *

(1) Annual CO_2 process emissions (metric tons) for each ammonia manufacturing unit.

* * * * *

(13) Annual amount of CO_2 (metric tons) collected from ammonia production and consumed on site for urea production and the method used to determine the CO_2 consumed in urea production.

* * * * *

(16) Annual quantity of excess hydrogen produced that is not consumed through the production of ammonia (metric tons).

Subpart H—Cement Production

■ 19. Amend § 98.83 by:

■ a. Revising paragraph (d)(1);

■ b. Revising parameters ‘‘CKD_{CaO}’’ and ‘‘CKD_{MgO}’’ of equation H–4 in paragraph (d)(2)(ii)(A); and

■ c. Revising paragraph (d)(3).

The revisions read as follows:

§ 98.83 Calculating GHG emissions.

* * * * *

(d) * * *

(1) Calculate CO_2 process emissions from all kilns at the facility using equation H–1 to this section:

$$CO_{2\,CMF} = \sum_{m=1}^{k}\left[CO_{2\,Cli,m} + CO_{2\,rm,m}\right] \qquad \text{(Eq. H–1)}$$

Where:

$CO_{2\,CMF}$ = Annual process emissions of CO_2 from cement manufacturing, metric tons.

$CO_{2\,Cli,m}$ = Total annual emissions of CO_2 from clinker production from kiln m, metric tons.

$CO_{2\,rm,m}$ = Total annual emissions of CO_2 from raw materials from kiln m, metric tons.

k = Total number of kilns at a cement manufacturing facility.

(2) * * *

(ii) * * *

(A) * * *

CKD_{ncCaO} = Quarterly non-calcined CaO content of CKD not recycled to the kiln, wt-fraction.

* * * * *

CKD_{ncMgO} = Quarterly non-calcined MgO content of CKD not recycled to the kiln, wt-fraction.

* * * * *

(3) *CO_2 emissions from raw materials from each kiln.* Calculate CO_2 emissions from raw materials using equation H–5 to this section:

$$CO_{2\,rm,m} = \sum_{i=1}^{M}\left[rm * TOC_{rm} * \frac{44}{12} * \frac{2000}{2205}\right] \qquad \text{(Eq. H–5)}$$

Where:

rm = The amount of raw material i consumed annually from kiln m, tons/yr (dry basis) or the amount of raw kiln feed consumed annually from kiln m, tons/yr (dry basis).

$CO_{2,rm,m}$ = Annual CO_2 emissions from raw materials from kiln m.

TOC_{rm} = Organic carbon content of raw material i from kiln m or organic carbon content of combined raw kiln feed (dry basis) from kiln m, as determined in § 98.84(c) or using a default factor of 0.2 percent of total raw material weight.

M = Number of raw materials or 1 if calculating emissions based on combined raw kiln feed.

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

* * * * *

■ 20. Amend § 98.86 by adding paragraphs (a)(4) through (8) and (b)(19) through (28) to read as follows:

§ 98.86 Data reporting requirements.

* * * * *

(a) * * *

(4) Annual arithmetic average of total CaO content of clinker at the facility, wt-fraction.

(5) Annual arithmetic average of non-calcined CaO content of clinker at the facility, wt-fraction.

(6) Annual arithmetic average of total MgO content of clinker at the facility, wt-fraction.

(7) Annual arithmetic average of non-calcined MgO content of clinker at the facility, wt-fraction.

(8) Annual facility CKD not recycled to the kiln(s), tons.

(b) * * *

(19) Annual arithmetic average of total CaO content of clinker at the facility, wt-fraction.

(20) Annual arithmetic average of non-calcined CaO content of clinker at the facility, wt-fraction.

(21) Annual arithmetic average of total MgO content of clinker at the facility, wt-fraction.

(22) Annual arithmetic average of non-calcined MgO content of clinker at the facility, wt-fraction.

(23) Annual arithmetic average of total CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(24) Annual arithmetic average of non-calcined CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(25) Annual arithmetic average of total MgO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(26) Annual arithmetic average of non-calcined MgO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(27) Annual facility CKD not recycled to the kiln(s), tons.

(28) The amount of raw kiln feed consumed annually at the facility, tons (dry basis).

Subpart I—Electronics Manufacturing

■ 21. Revise and republish § 98.91 to read as follows:

§ 98.91 Reporting threshold.

(a) You must report GHG emissions under this subpart if electronics manufacturing production processes, as defined in § 98.90, are performed at your facility and your facility meets the requirements of either § 98.2(a)(1) or (2). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in § 98.2(a)(2), follow the requirements of § 98.2(b), with one exception. Rather than using the calculation methodologies in § 98.93 to calculate emissions from electronics manufacturing production processes, calculate emissions of each fluorinated GHG from electronics manufacturing production processes by using paragraph (a)(1), (2), or (3) of this section, as appropriate, and then sum the emissions of each fluorinated GHG and account for fluorinated heat transfer fluid emissions by using paragraph (a)(4) of this section.

(1) If you manufacture semiconductors or MEMS you must calculate annual production process emissions resulting from the use of each input gas for threshold applicability purposes using either the default emission factors shown in table I–1 to this subpart and equation I–1A to this section, or the consumption of each input gas, the default emission factors shown in table I–2 to this subpart, and equation I–1B to this section.

$$E_i = S * EF_i * GWP_i * 0.001 \quad \text{(Eq. I–1A)}$$

Where:

E_i = Annual production process emissions of gas i for threshold applicability purposes (metric tons CO_2e).

S = 100 percent of annual manufacturing capacity of a facility as calculated using equation I–5 to this section (m^2).

EF_i = Emission factor for gas i (kg/m^2) shown in table I–1 to this subpart.

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Emitted gas.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \quad \text{(Eq. I–1B)}$$

Where:

E_i = Annual production process emissions resulting from the use of input gas i for threshold applicability purposes (metric tons CO_2e).

C_i = Annual GHG (input gas i) purchases or consumption (kg). Only gases that are used in semiconductor or MEMS manufacturing processes listed at § 98.90(a)(1) through (4) must be considered for threshold applicability purposes.

$(1–U_i)$, BCF_4, and BC_2F_6 = Default emission factors for the gas consumption-based threshold applicability determination listed in table I–2 to this subpart.

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(2) If you manufacture LCDs, you must calculate annual production process emissions resulting from the use of each input gas for threshold applicability purposes using either the default emission factors shown in table I–1 to this subpart and equation I–2A to this section or the consumption of each input gas, the default emission factors shown in table I–2 to this subpart, and equation I–2B to this section.

$$E_i = S * EF_i * GWP_i * 0.000001 \quad \text{(Eq. I–2A)}$$

Where:

E_i = Annual production process emissions of gas i for threshold applicability purposes (metric tons CO_2e).

S = 100 percent of annual manufacturing capacity of a facility as calculated using equation I–5 to this section (m^2).

EF_i = Emission factor for gas i (g/m^2).

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

0.000001 = Conversion factor from g to metric tons.

i = Emitted gas.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \quad \text{(Eq. I–2B)}$$

Where:

E_i = Annual production process emissions resulting from the use of input gas i for threshold applicability purposes (metric tons CO_2e).

C_i = Annual GHG (input gas i) purchases or consumption (kg). Only gases that are used in LCD manufacturing processes listed at § 98.90(a)(1) through (4) must be considered for threshold applicability purposes.

$(1–U_i)$, BCF_4, and BC_2F_6 = Default emission factors for the gas consumption-based threshold applicability determination listed in table I–2 to this subpart.

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(3) If you manufacture PVs, you must calculate annual production process emissions resulting from the use of each input gas i for threshold applicability purposes using gas-appropriate GWP values shown in table A–1 to subpart A of this part, the default emission factors shown in table I–2 to this subpart, and equation I–3 to this section.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \quad \text{(Eq. I–3)}$$

Where:

E_i = Annual production process emissions resulting from the use of input gas i for threshold applicability purposes (metric tons CO_2e).

C_i = Annual fluorinated GHG (input gas i) purchases or consumption (kg). Only gases that are used in PV manufacturing processes listed at § 98.90(a)(1) through (4) must be considered for threshold applicability purposes.

$(1 – U_i)$, BCF_4, and BC_2F_6 = Default emission factors for the gas consumption-based threshold applicability determination listed in table I–2 to this subpart.

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(4) You must calculate total annual production process emissions for threshold applicability purposes using equation I–4 to this section.

$$E_T = \delta * \sum_i E_i \qquad \text{(Eq. I–4)}$$

Where:

E_T = Annual production process emissions of all fluorinated GHGs for threshold applicability purposes (metric tons CO_2e).

δ = Factor accounting for fluorinated heat transfer fluid emissions, estimated as 10 percent of total annual production process emissions at a semiconductor facility. Set equal to 1.1 when equation I–4 to this section is used to calculate total annual production process emissions from semiconductor manufacturing. Set equal to 1 when equation I–4 to this section is used to calculate total annual production process emissions from MEMS, LCD, or PV manufacturing.

E_i = Annual production process emissions of gas i for threshold applicability purposes (metric tons CO_2e), as calculated in equations I–1a, I–1b, I–2a, I–2b, or I–3 to this section.

i = Emitted gas.

(b) You must calculate annual manufacturing capacity of a facility using equation I–5 to this section.

$$S = \sum_x^{12} W_x \qquad \text{(Eq. I–5)}$$

Where:

S = 100 percent of annual manufacturing capacity of a facility (m^2).

W_x = Maximum substrate starts of fab f in month x (m^2 per month).

x = Month.

■ 22. Amend § 98.92 by revising paragraph (a) introductory text to read as follows:

§ 98.92 GHGs to report.

(a) You must report emissions of fluorinated GHGs (as defined in § 98.6), N_2O, and fluorinated heat transfer fluids (as defined in § 98.6). The fluorinated GHGs and fluorinated heat transfer fluids that are emitted from electronics manufacturing production processes include, but are not limited to, those listed in table I–21 to this subpart. You must individually report, as appropriate:

* * * * *

■ 23. Amend § 98.93 by:

■ a. Revising paragraph (a);

■ b. Revising the introductory text of paragraph (e);

■ c. Revising parameters ‘‘UT_{ij}’’ and ‘‘Td_{ijp}’’ of equation I–15 in paragraph (g); and

■ d. Revising paragraphs (h)(1) and (i).

The revisions read as follows:

§ 98.93 Calculating GHG emissions.

(a) You must calculate total annual emissions of each fluorinated GHG emitted by electronics manufacturing production processes from each fab (as defined in § 98.98) at your facility, including each input gas and each by-product gas. You must use either default gas utilization rates and by-product formations rates according to the procedures in paragraph (a)(1), (2), (6), or (7) of this section, as appropriate, or the stack test method according to paragraph (i) of this section, to calculate emissions of each input gas and each by-product gas.

(1) If you manufacture semiconductors, you must adhere to the procedures in paragraphs (a)(1)(i) through (iii) of this section. You must calculate annual emissions of each input gas and of each by-product gas using equations I–6, I–7, and I–9 to this section. If your fab uses less than 50 kg of a fluorinated GHG in one reporting year, you may calculate emissions as equal to your fab’s annual consumption for that specific gas as calculated in equation I–11 to this section, plus any by-product emissions of that gas calculated under paragraph (a) of this section.

$$ProcesstypeE_i = \sum_{j=1}^{N} E_{ij} \qquad \text{(Eq. I–6)}$$

Where:

$ProcesstypeE_i$ = Annual emissions of input gas i from the process type on a fab basis (metric tons).

E_{ij} = Annual emissions of input gas i from process sub-type or process type j as calculated in equation I–8A to this section (metric tons).

N = The total number of process sub-types j that depends on the electronics manufacturing fab and emission calculation methodology. If E_{ij} is calculated for a process type j in equation I–8A to this section, N = 1.

i = Input gas.

j = Process sub-type or process type.

$$ProcesstypeBE_k = \sum_{j=1}^{N} \sum_i BE_{kij} \qquad \text{(Eq. I–7)}$$

Where:

$ProcesstypeBE_k$ = Annual emissions of by-product gas k from the processes type on a fab basis (metric tons).

BE_{kij} = Annual emissions of by-product gas k formed from input gas i used for process sub-type or process type j as calculated in equation I–8B to this section (metric tons).

N = The total number of process sub-types j that depends on the electronics manufacturing fab and emission calculation methodology. If BE_{kij} is calculated for a process type j in equation I–8B to this section, N = 1.

i = Input gas.

j = Process sub-type, or process type.

k = By-product gas.

(i) You must calculate annual fab-level emissions of each fluorinated GHG used for the plasma etching/wafer cleaning process type using default utilization and by-product formation rates as shown in table I–3 or I–4 to this subpart, and by using equations I–8A and I–8B to this section.

$$E_{ij} = C_{ij} * \left(1 - U_{ij}\right) * \left(1 - \left(a_{ij} * d_{ij} * UT_{ij}\right)\right) * 0.001 \qquad \text{(Eq. I–8A)}$$

Where:

E_{ij} = Annual emissions of input gas i from process sub-type or process type j, on a fab basis (metric tons).

C_{ij} = Amount of input gas i consumed for process sub-type or process type j, as calculated in equation I–13 to this section, on a fab basis (kg).

U_{ij} = Process utilization rate for input gas i for process sub-type or process type j (expressed as a decimal fraction).

a_{ij} = Fraction of input gas i used in process sub-type or process type j with abatement systems, on a fab basis (expressed as a decimal fraction).

d_{ij} = Fraction of input gas i destroyed or removed when fed into abatement systems by process tools where process sub-type, or process type j is used, on a fab basis, calculated by taking the tool weighted average of the claimed DREs for input gas i on tools that use process type or process sub-type j (expressed as a decimal fraction). This is zero unless the facility adheres to the requirements in § 98.94(f).

UT_{ij} = The average uptime factor of all abatement systems connected to process tools in the fab using input gas i in process sub-type or process type j, as calculated in equation I–15 to this section, on a fab basis (expressed as a decimal fraction).

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

j = Process sub-type or process type.

$$BE_{kij} = B_{kij} * C_{ij} * \left(1 - \left(a_{kij} * d_{kij} * UT_{kij}\right)\right) * 0.001 \qquad \text{(Eq. I–8B)}$$

Where:

BE_{kij} = Annual emissions of by-product gas k formed from input gas i from process sub-type or process type j, on a fab basis (metric tons).

B_{kij} = By-product formation rate of gas k created as a by-product per amount of input gas i (kg) consumed by process sub-type or process type j (kg). If all input gases consumed by a chamber cleaning process sub-type are non-carbon containing input gases, this is zero when the combination of the non-carbon containing input gas and chamber cleaning process sub-type is never used to clean chamber walls on equipment that process carbon-containing films during the year (*e.g.,* when NF_3 is used in remote plasma cleaning processes to only clean chambers that never process carbon-containing films during the year). If all input gases consumed by an etching and wafer cleaning process sub-type are non-carbon containing input gases, this is zero when the combination of the non-carbon containing input gas and etching and wafer cleaning process sub-type is never used to etch or wafer clean carbon-containing films during the year.

C_{ij} = Amount of input gas i consumed for process sub-type, or process type j, as calculated in equation I–13 to this section, on a fab basis (kg).

a_{kij} = Fraction of input gas i used for process sub-type, or process type j with abatement systems, on a fab basis (expressed as a decimal fraction).

d_{kij} = Fraction of by-product gas k destroyed or removed in when fed into abatement systems by process tools where process sub-type or process type j is used, on a fab basis, calculated by taking the tool weighted average of the claimed DREs for by-product gas k on tools that use input gas i in process type or process sub-type j (expressed as a decimal fraction). This is zero unless the facility adheres to the requirements in § 98.94(f).

UT_{kij} = The average uptime factor of all abatement systems connected to process tools in the fab emitting by-product gas k, formed from input gas i in process sub-type or process type j, on a fab basis (expressed as a decimal fraction). For this equation, UT_{kij} is assumed to be equal to UT_{ij} as calculated in equation I–15 to this section.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

j = Process sub-type or process type.

k = By-product gas.

(ii) You must calculate annual fab-level emissions of each fluorinated GHG used for each of the process sub-types associated with the chamber cleaning process type, including in-situ plasma chamber clean, remote plasma chamber clean, and in-situ thermal chamber clean, using default utilization and by-product formation rates as shown in table I–3 or I–4 to this subpart, and by using equations I–8A and I–8B to this section.

(iii) If default values are not available for a particular input gas and process type or sub-type combination in tables I–3 or I–4, you must follow the procedures in paragraph (a)(6) of this section.

(2) If you manufacture MEMS or PVs and use semiconductor tools and processes, you may use § 98.3(a)(1) to calculate annual fab-level emissions for those processes. For all other tools and processes used to manufacture MEMs, LCD and PV, you must calculate annual fab-level emissions of each fluorinated GHG used for the plasma etching and chamber cleaning process types using default utilization and by-product formation rates as shown in table I–5, I–6, or I–7 to this subpart, as appropriate, and by using equations I–8A and I–8B to this section. If default values are not available for a particular input gas and process type or sub-type combination in tables I–5, I–6, or I–7 to this subpart, you must follow the procedures in paragraph (a)(6) of this section. If your fab uses less than 50 kg of a fluorinated GHG in one reporting year, you may calculate emissions as equal to your fab's annual consumption for that specific gas as calculated in equation I–11 to this section, plus any by-product emissions of that gas calculated under this paragraph (a).

(3)–(5) [Reserved]

(6) If you are required, or elect, to perform calculations using default emission factors for gas utilization and by-product formation rates according to the procedures in paragraph (a)(1) or (2) of this section, and default values are not available for a particular input gas and process type or sub-type combination in tables I–3, I–4, I–5, I–6, or I–7 to this subpart, you must use a utilization rate (U_{ij}) of 0.2 (*i.e.,* a 1–U_{ij} of 0.8) and by-product formation rates of 0.15 for CF_4 and 0.05 for C_2F_6 and use equations I–8A and I–8B to this section.

(7) If your fab employs hydrocarbon-fuel-based combustion emissions control systems (HC fuel CECS), including, but not limited to, abatement systems as defined at § 98.98, that were purchased and installed on or after January 1, 2025, to control emissions from tools that use either NF_3 in remote plasma cleaning processes or F_2 as an input gas in any process type or sub-type, you must calculate the amount CF_4 produced within and emitted from such systems using equation I–9 to this section using default utilization and by-product formation rates as shown in table I–3 or I–4 to this subpart. A HC fuel CECS is assumed not to form CF_4 from F_2 if the electronics manufacturer can certify that the rate of conversion from F_2 to CF_4 is <0.1% for that HC fuel CECS.

$$EAB_{CF_4} = \sum_j C_{F_2,j} \bullet (1 - U_{F_2,j}) \bullet a_{F_2,j} \bullet UT_{F_2,j} \bullet AB_{CF_4,F_2} + C_{NF_3,RPC} \bullet B_{F_2,NF_3} \bullet a_{NF_3,RPC} \bullet UT_{NF_3,RPC,F2} \bullet AB_{CF_4,F_2} \qquad \text{(Eq. I–9)}$$

Where:

EAB_{CF4} = Emissions of CF_4 from HC fuel CECS when direct reaction between hydrocarbon fuel and F_2 is not certified not to occur by the emissions control system manufacturer or electronics manufacturer, kg.

$C_{F2,j}$ = Amount of F_2 consumed for process type or sub-type j, as calculated in equation I–13 to this section, on a fab basis (kg).

$U_{F2,j}$ = Process utilization rate for F_2 for process type or sub-type j (expressed as a decimal fraction).

$a_{F2,j}$ = Within process sub-type or process type j, fraction of F_2 used in process tools with HC fuel CECS that are not certified not to form CF_4, on a fab basis, where the numerator is the number of tools that are equipped with HC fuel CECS that are not certified not to form CF_4 that use F_2 in process type j and the denominator is the total number of tools in the fab that use F_2 in process type j (expressed as a decimal fraction).

$UT_{F2,j}$ = The average uptime factor of all HC fuel CECS connected to process tools in the fab using F_2 in process sub-type or process type j (expressed as a decimal fraction).

$AB_{CF4,F2}$ = Mass fraction of F_2 in process exhaust gas that is converted into CF_4 by direct reaction with hydrocarbon fuel in a HC fuel CECS. The default value of $AB_{CF4,F2}$ = 0.116.

$C_{NF3,RPC}$ = Amount of NF_3 consumed in remote plasma cleaning processes, as calculated in equation I–13 to this section, on a fab basis (kg).

$B_{F2,NF3}$ = By-product formation rate of F_2 created as a by-product per amount of NF_3 (kg) consumed in remote plasma cleaning processes (kg).

$a_{NF3,RPC}$ = Within remote plasma cleaning processes, fraction of NF_3 used in process tools with HC fuel CECS that are not certified not to form CF_4, where the numerator is the number of tools running remote plasma cleaning processes that are equipped with HC fuel CECS that are not certified not to form CF_4 that use NF_3 and the denominator is the total number of tools that run remote plasma clean processes in the fab that use NF_3 (expressed as decimal fraction).

$UT_{NF3,RPC,F2}$ = The average uptime factor of all HC fuel CECS connected to process tools in the fab emitting by-product gas F_2, formed from input gas NF_3 in remote plasma cleaning processes, on a fab basis (expressed as a decimal fraction). For this equation, $UT_{NF3,RPC,F2}$ is assumed to be equal to $UT_{NF3,RPC}$ as calculated in equation I–15 to this section.

j = Process type or sub-type.

* * * * *

(e) You must calculate the amount of input gas i consumed, on a fab basis, for each process sub-type or process type j, using equation I–13 to this section. Where a gas supply system serves more than one fab, equation I–13 to this section is applied to that gas which has been apportioned to each fab served by that system using the apportioning factors determined in accordance with § 98.94(c). If you elect to calculate emissions using the stack test method in paragraph (i) of this section and to use this paragraph (e) to calculate the fraction each fluorinated input gas i exhausted from tools with abatement systems and the fraction of each by-product gas k exhausted from tools with abatement systems, you may substitute ‘‘The set of tools with abatement systems’’ for ‘‘Process sub-type or process type’’ in the definition of ‘‘j’’ in equation I–13 to this section.

* * * * *

(g) * * *

UT_{ij} = The average uptime factor of all abatement systems connected to process tools in the fab using input gas i in process sub-type or process type j (expressed as a decimal fraction). The average uptime factor may be set to one (1) if all the abatement systems for the relevant input gas i and process sub-type or type j are interlocked with all the tools using input gas i in process sub-type or type j and feeding the abatement systems such that no gas can flow to the tools if the abatement systems are not in operational mode.

Td_{ijp} = The total time, in minutes, that abatement system p, connected to process tool(s) in the fab using input gas i in process sub-type or process type j, is not in operational mode, as defined in § 98.98, when at least one of the tools connected to abatement system p is in operation. If your fab uses redundant abatement systems, you may account for Td_{ijp} as specified in § 98.94(f)(4)(vi).

* * * * *

(h) * * *

(1) If you use a fluorinated chemical both as a fluorinated heat transfer fluid and in other applications, you may calculate and report either emissions from all applications or from only those specified in the definition of fluorinated heat transfer fluids in § 98.6.

* * * * *

(i) *Stack test method.* As an alternative to the default emission factor method in paragraph (a) of this section, you may calculate fab-level fluorinated GHG emissions using fab-specific emission factors developed from stack testing. In this case, you must comply with the stack test method specified in paragraph (i)(3) of this section.

(1)–(2) [Reserved]

(3) *Stack system stack test method.* For each stack system in the fab, measure the emissions of each fluorinated GHG from the stack system by conducting an emission test. In addition, measure the fab-specific consumption of each fluorinated GHG by the tools that are vented to the stack systems tested. Measure emissions and consumption of each fluorinated GHG as specified in § 98.94(j). Develop fab-specific emission factors and calculate fab-level fluorinated GHG emissions using the procedures specified in paragraphs (i)(3)(i) through (viii) of this section. All emissions test data and procedures used in developing emission factors must be documented and recorded according to § 98.97.

(i) You must measure the fab-specific fluorinated GHG consumption of the tools that are vented to the stack systems during the emission test as specified in § 98.94(j)(3). Calculate the consumption for each fluorinated GHG for the test period.

(ii) You must calculate the emissions of each fluorinated GHG consumed as an input gas using equation I–17 to this section and each fluorinated GHG formed as a by-product gas using equation I–18 to this section and the procedures specified in paragraphs (i)(3)(ii)(A) through (E) of this section. If a stack system is comprised of multiple stacks, you must sum the emissions from each stack in the stack system when using equation I–17 or equation I–18 to this section.

$$E_{is} = MW_i * Q_s * \frac{1}{SV} * \frac{1}{10^3} * \sum_{m=1}^{N} \frac{X_{ism}}{10^9} * \Delta t_m \qquad \text{(Eq. I–17)}$$

Where:

E_{is} = Total fluorinated GHG input gas i, emitted from stack system s, during the sampling period (kg).

X_{ism} = Average concentration of fluorinated GHG input gas i in stack system s, during the time interval m (ppbv).

MW_i = Molecular weight of fluorinated GHG input gas i (g/g-mole).

Q_s = Flow rate of the stack system s, during the sampling period (m^3/min).

SV = Standard molar volume of gas (0.0240 m^3/g-mole at 68 °F and 1 atm).

Δt_m = Length of time interval m (minutes). Each time interval in the FTIR sampling period must be less than or equal to 60 minutes (for example an 8 hour sampling period would consist of at least 8 time intervals).

$1/10^3$ = Conversion factor (1 kilogram/1,000 grams).

i = Fluorinated GHG input gas.

s = Stack system.

N = Total number of time intervals m in sampling period.

m = Time interval.

$$E_{ks} = MW_k * Q_s * \frac{1}{SV} * \frac{1}{10^3} * \sum_{m=1}^{N} \frac{X_{ksm}}{10^9} * \Delta t_m \qquad \text{(Eq. I–18)}$$

Where:

E_{ks} = Total fluorinated GHG by-product gas k, emitted from stack system s, during the sampling period (kg).

X_{ks} = Average concentration of fluorinated GHG by-product gas k in stack system s, during the time interval m (ppbv).

MW_k = Molecular weight of the fluorinated GHG by-product gas k (g/g-mole).

Q_s = Flow rate of the stack system s, during the sampling period (m^3/min).

SV = Standard molar volume of gas (0.0240 m^3/g-mole at 68 °F and 1 atm).

Δt_m = Length of time interval m (minutes). Each time interval in the FTIR sampling period must be less than or equal to 60 minutes (for example an 8 hour sampling period would consist of at least 8 time intervals).

$1/10^3$ = Conversion factor (1 kilogram/1,000 grams).

k = Fluorinated GHG by-product gas.

s = Stack system.

N = Total number of time intervals m in sampling period.

m = Time interval.

(A) If a fluorinated GHG is consumed during the sampling period, but emissions are not detected, use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ‘‘X_{ism}’’ in equation I–17 to this section.

(B) If a fluorinated GHG is consumed during the sampling period and detected intermittently during the sampling period, use the detected concentration for the value of ‘‘X_{ism}’’ in equation I–17 to this section when available and use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ‘‘X_{ism}’’ when the fluorinated GHG is not detected.

(C) If an expected or possible by-product, as listed in table I–17 to this subpart, is detected intermittently during the sampling period, use the measured concentration for ‘‘X_{ksm}’’ in equation I–18 to this section when available and use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ‘‘X_{ksm}’’ when the fluorinated GHG is not detected.

(D) If a fluorinated GHG is not consumed during the sampling period and is an expected by-product gas as listed in table I–17 to this subpart and is not detected during the sampling period, use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ‘‘X_{ksm}’’ in equation I–18 to this section.

(E) If a fluorinated GHG is not consumed during the sampling period and is a possible by-product gas as listed in table I–17 to this subpart, and is not detected during the sampling period, then assume zero emissions for that fluorinated GHG for the tested stack system.

(iii) You must calculate a fab-specific emission factor for each fluorinated GHG input gas consumed (in kg of fluorinated GHG emitted per kg of input gas i consumed) in the tools that vent to stack systems, as applicable, using equations I–19A and I–19B to this section or equations I–19A and I–19C to this section. Use equation I–19A to this section to calculate the controlled emissions for each carbon-containing fluorinated GHG that would result during the sampling period if the utilization rate for the input gas were equal to 0.2 ($E_{imax,f}$). If $\Sigma_s E_{i,s}$ (the total measured emissions of the fluorinated GHG across all stack systems, calculated based on the results of equation I–17 to this section) is less than or equal to $E_{imax,f}$ calculated in equation I–19A to this section, use equation I–19B to this section to calculate the emission factor for that fluorinated GHG. If $\Sigma_s E_{i,s}$ is larger than the $E_{imax,f}$ calculated in equation I–19A to this section, use equation I–19C to this section to calculate the emission factor and treat the difference between the total measured emissions $\Sigma_s E_{i,s}$ and the maximum expected controlled emissions $E_{imax,f}$ as a by-product of the other input gases, using equation I–20 to this section. For all fluorinated GHGs that do not contain carbon, use equation I–19B to this section to calculate the emission factor for that fluorinated GHG.

$$E_{imax,f} = 0.8 \bullet Activity_{if} \bullet (1 - UT_f \bullet a_{if} \bullet d_{if}) \qquad \text{(Eq. I–19A)}$$

Where:

$E_{imax,f}$ = Maximum expected controlled emissions of gas i from its use an input gas during the stack testing period, from fab f (max kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i, for fab f, in the tools vented to the stack systems being tested, during the sampling period, as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in equation I–23 to this section (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

a_{if} = Fraction of input gas i emitted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated in equation I–24C to this section.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in equation I–24A to this section (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

$$EF_{if} = \frac{\sum_s (E_{is})}{Activity_{if} * \left(UT_f + \left(\frac{1 - UT_f}{1 - (a_{if} \bullet d_{if})} \right) \right)} \qquad \text{(Eq. I–19B)}$$

Where:

EF_{if} = Emission factor for fluorinated GHG input gas i, from fab f, representing 100 percent abatement system uptime (kg emitted/kg input gas consumed).

E_{is} = Mass emission of fluorinated GHG input gas i from stack system s during the sampling period (kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i, for fab f during the sampling period, as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in equation I–23 to this section (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

a_{if} = Fraction of fluorinated GHG input gas i exhausted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated in equation I–24C to this section.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in equation I–24A to this section (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

f = Fab.

i = Fluorinated GHG input gas.

s = Stack system.

$$EF_{if} = 0.8 \bullet (1 - a_{if} \bullet d_{if}) \qquad \text{(Eq. I–19C)}$$

EF_{if} = Emission factor for input gas i, from fab f, representing a 20-percent utilization rate and a 100-percent abatement system uptime (kg emitted/kg input gas consumed).

a_{if} = Fraction of input gas i emitted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated in equation I–24C to this section.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in equation I–24A to this section (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

(iv) You must calculate a fab-specific emission factor for each fluorinated GHG formed as a by-product (in kg of fluorinated GHG per kg of total fluorinated GHG consumed) in the tools vented to stack systems, as applicable, using equation I–20 to this section. When calculating the by-product emission factor for an input gas for which $\Sigma_s E_{i,s}$ equals or exceeds $E_{imax,f}$, exclude the consumption of that input gas from the term "$\Sigma(Activity_{if})$."

$$EF_{kf} = \frac{\sum_s (E_{ks})}{\sum_i Activity_{if} * \left(UT_f + \left(\frac{1 - UT_f}{1 - (a_{kif} * d_{kif})} \right) \right)} \qquad \text{(Eq. I–20)}$$

Where:

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, from fab f, representing 100 percent abatement system uptime (kg emitted/kg of all input gases consumed in tools vented to stack systems).

E_{ks} = Mass emission of fluorinated GHG by-product gas k, emitted from stack system s, during the sampling period (kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i for fab f in tools vented to stack systems during the sampling period as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in equation I–23 to this section (expressed as decimal fraction).

a_{kif} = Fraction of by-product k emitted from tools using input gas i with abatement systems in fab f (expressed as a decimal fraction), as calculated using equation I–24D to this section.

d_{kif} = Fraction of fluorinated GHG by-product gas k generated from input gas i destroyed or removed when fed into abatement systems by process tools in fab f, as calculated in equation I–24B to this section (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

k = Fluorinated GHG by-product gas.

s = Stack system.

(v) You must calculate annual fab-level emissions of each fluorinated GHG consumed using equation I–21 to this section.

$$E_{if} = EF_{if} \bullet C_{if} \bullet UT_f + \frac{EF_{if}}{(1 - (a_{if} \bullet d_{if}))} \bullet C_{if} \bullet (1 - UT_f) \qquad \text{(Eq. I–21)}$$

Where:

E_{if} = Annual emissions of fluorinated GHG input gas i (kg/year) from the stack systems for fab f.

EF_{if} = Emission factor for fluorinated GHG input gas i emitted from fab f, as calculated in equation I–19 to this section (kg emitted/kg input gas consumed).

C_{if} = Total consumption of fluorinated GHG input gas i in tools that are vented to stack systems, for fab f, for the reporting year, as calculated using equation I–13 to this section (kg/year).

UT_f = The total uptime of all abatement systems for fab f, during the reporting year, as calculated using equation I–23 to this section (expressed as a decimal fraction).

a_{if} = Fraction of fluorinated GHG input gas i emitted from tools with abatement systems in fab f (expressed as a decimal fraction), as calculated using equation I–24C or I–24D to this section.

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f that are included in the stack testing option, as calculated in equation I–24A to this section (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

(vi) You must calculate annual fab-level emissions of each fluorinated GHG by-product formed using equation I–22 to this section.

$$E_{kf} = EF_{kf} \bullet \sum_i C_{if} \bullet UT_f + EF_{kf} \bullet \sum_i \frac{C_{if} \bullet (1 - UT_f)}{1 - a_{kif} \bullet d_{kif}} \qquad \text{(Eq. I–22)}$$

Where:

E_{kf} = Annual emissions of fluorinated GHG by-product gas k (kg/year) from the stack for fab f.

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, emitted from fab f, as calculated in equation I–20 to this section (kg emitted/kg of all fluorinated input gases consumed).

C_{if} = Total consumption of fluorinated GHG input gas i in tools that are vented to stack systems, for fab f, for the reporting year, as calculated using equation I–13 to this section.

UT_f = The total uptime of all abatement systems for fab f, during the reporting year as calculated using equation I–23 to this section (expressed as a decimal fraction).

a_{kif} = Estimate of fraction of fluorinated GHG by-product gas k emitted in fab f from tools using input gas i with abatement systems (expressed as a decimal fraction), as calculated using equation I–24D to this section.

d_{kif} = Fraction of fluorinated GHG by-product k generated from input gas i destroyed or removed when fed into abatement systems by process tools in fab f that are included in the stack testing option, as calculated in equation I–24B to this section (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

k = Fluorinated GHG by-product.

(vii) When using the stack testing method described in this paragraph (i), you must calculate abatement system uptime on a fab basis using equation I–23 to this section. When calculating abatement system uptime for use in equation I–19 and I–20 to this section, you must evaluate the variables ''Tdpf'' and ''UTpf'' for the sampling period instead of the reporting year.

$$UT_f = 1 - \frac{\sum_p Td_{pf}}{\sum_p UT_{pf}} \qquad \text{(Eq. I–23)}$$

Where:

UT_f = The average uptime factor for all abatement systems in fab f (expressed as a decimal fraction). The average uptime factor may be set to one (1) if all the abatement systems in fab f are interlocked with all the tools feeding the abatement systems such that no gas can flow to the tools if the abatement systems are not in operational mode.

Td_{pf} = The total time, in minutes, that abatement system p, connected to process tool(s) in fab f, is not in operational mode as defined in § 98.98. If your fab uses redundant abatement systems, you may account for Tdpf as specified in § 98.94(f)(4)(vi).

UT_{pf} = Total time, in minutes per year, in which the tool(s) connected at any point during the year to abatement system p, in fab f could be in operation. For determining the amount of tool operating time, you may assume that tools that were installed for the whole of the year were operated for 525,600 minutes per year. For tools that were installed or uninstalled during the year, you must prorate the operating time to account for the days in which the tool was not installed; treat any partial day that a tool was installed as a full day (1,440 minutes) of tool operation. For an abatement system that has more than one connected tool, the tool operating time is 525,600 minutes per year if there was at least one tool installed at all times throughout the year. If you have tools that are idle with no gas flow through the tool, you may calculate total tool time using the actual time that gas is flowing through the tool.

f = Fab.

p = Abatement system.

(viii) When using the stack testing option described in this paragraph (i) and when using more than one DRE for the same input gas i or by-product gas k, you must calculate the weighted-average fraction of each fluorinated input gas i and each fluorinated by-product gas k that has more than one DRE and that is destroyed or removed in abatement systems for each fab f, as applicable, by using equation I–24A to this section (for input gases) and equation I–24B to this section (for by-product gases) and table I–18 to this subpart. If default values are not available in table I–18 for a particular input gas, you must use a value of 10.

$$D_{if} = \frac{\sum_p (\gamma_{i,p} \cdot \sum_{DREy} n_{i,p,DREy} \cdot DRE_y) + \sum_{DREz} DRE_z \cdot m_{i,q,DREz}}{\sum_p \gamma_{i,p} \cdot n_{i,p,a} + m_{i,q,a}} \qquad \text{(Eq. I–24A)}$$

$$D_{kif} = \frac{\sum_p (\gamma_{k,i,p} \cdot \sum_{DREy} n_{k,i,p,DREy} \cdot DRE_y) + \sum_{DREz} DRE_z \cdot m_{k,i,q,DREz}}{\sum_p \gamma_{k,i,p} \cdot n_{k,i,p,a} + m_{k,i,q,a}} \qquad \text{(Eq. I–24B)}$$

Where:

d_{if} = The average weighted fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f (expressed as a decimal fraction).

d_{kif} = The average weighted fraction of fluorinated GHG by-product gas k generated from input gas i that is destroyed or removed when fed into abatement systems by process tools in fab f (expressed as a decimal fraction).

$n_{i,p,DREy}$ = Number of tools that use gas i, that run chamber cleaning process p, and that are equipped with abatement systems for gas i that have the DRE DREy.

$m_{i,q,DREz}$ = Number of tools that use gas i, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i that have the DRE DREz.

$n_{i,p,a}$ = Total number of tools that use gas i, run chamber cleaning process type p, and that are equipped with abatement systems for gas i.

$m_{i,q,a}$ = Total number of tools that use gas i, run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i.

$n_{k,i,p,DREy}$ = Number of tools that use gas i, generate by-product k, that run chamber cleaning process p, and that are equipped with abatement systems for gas i that have the DRE DREy.

$m_{k,i,q,DREz}$ = Number of tools that use gas i, generate by-product k, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i that have the DRE DREz.
$n_{k,i,p,a}$ = Total number of tools that use gas i, generate by-product k, run chamber cleaning process type p, and that are equipped with abatement systems for gas i.
$m_{k,i,q,a}$ = Total number of tools that use gas i, generate by-product k, run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i.
$\gamma_{i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of input gas i from tools running process sub-type p processes to uncontrolled emissions per tool of input gas i from process tools running process type q processes.
$\gamma_{k,i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of input gas i from tools running process sub-type p processes to uncontrolled emissions per tool of input gas i from process tools running process type q processes.
DRE_y = Default or alternative certified DRE for gas i for abatement systems connected to CVD tool.
DRE_z = Default or alternative certified DRE for gas i for abatement systems connected to etching and/or wafer cleaning tool.
p = Chamber cleaning process sub-type.
q = Reference process type. There is one process type q that consists of the combination of etching and/or wafer cleaning processes.
f = Fab.
i = Fluorinated GHG input gas.

(ix) When using the stack testing method described in this paragraph (i), you must calculate the fraction each fluorinated input gas i exhausted in fab f from tools with abatement systems and the fraction of each by-product gas k exhausted from tools with abatement systems, as applicable, by following either the procedure set forth in paragraph (i)(3)(ix)(A) of this section or the procedure set forth in paragraph (i)(3)(ix)(B) of this section.

(A) Use equation I–24C to this section (for input gases) and equation I–24D to this section (for by-product gases) and table I–18 to this subpart. If default values are not available in table I–18 for a particular input gas, you must use a value of 10.

$$A_{i,f} = \frac{\sum_p \gamma_{i,p} \cdot n_{i,p,a} + m_{i,q,a}}{\sum_p \gamma_{i,p} \cdot n_{i,p} + m_{i,q}} \qquad \text{(Eq. I–24C)}$$

Where:

a_{if} = Fraction of fluorinated input gas i exhausted from tools with abatement systems in fab f (expressed as a decimal fraction).
$n_{i,p,a}$ = Number of tools that use gas i, that run chamber cleaning process sub-type p, and that are equipped with abatement systems for gas i.
$m_{i,q,a}$ = Number of tools that use gas i, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas i.
$n_{i,p}$ = Total number of tools using gas i and running chamber cleaning process sub-type p.
$m_{i,q}$ = Total number of tools using gas i and running etch and/or wafer cleaning processes.
$\gamma_{i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of input gas i from tools running process type p processes to uncontrolled emissions per tool of input gas i from process tools running process type q processes.
p = Chamber cleaning process sub-type.
q = Reference process type. There is one process type q that consists of the combination of etching and/or wafer cleaning processes.

$$A_{k,i,f} = \frac{\sum_p \gamma_{k,i,p} \cdot n_{k,i,p,a} + m_{k,i,q,a}}{\sum_p \gamma_{k,i,p} \cdot n_{k,i,p} + m_{k,i,q}} \qquad \text{Eq. I–24D}$$

Where:

$a_{k,i,f}$ = Fraction of by-product gas k exhausted from tools using input gas i with abatement systems in fab f (expressed as a decimal fraction).
$n_{k,i,p,a}$ = Number of tools that exhaust by-product gas k from input gas i, that run chamber cleaning process p, and that are equipped with abatement systems for gas k.
$m_{k,i,q,a}$ = Number of tools that exhaust by-product gas k from input gas i, that run etch and/or wafer cleaning processes, and that are equipped with abatement systems for gas k.
$n_{k,i,p}$ = Total number of tools emitting by-product k from input gas i and running chamber cleaning process p.
$m_{k,i,q}$ = Total number of tools emitting by-product k from input gas i and running etch and/or wafer cleaning processes.
$\gamma_{k,i,p}$ = Default factor reflecting the ratio of uncontrolled emissions per tool of by-product gas k from input gas i from tools running chamber cleaning process p to uncontrolled emissions per tool of by-product gas k from input gas i from process tools running etch and/or wafer cleaning processes.
p = Chamber cleaning process sub-type.
q = Reference process type. There is one process type q that consists of the combination of etching and/or wafer cleaning processes.

(B) Use paragraph (e) of this section to apportion consumption of gas i either to tools with abatement systems and tools without abatement systems or to each process type or sub-type, as applicable. If you apportion consumption of gas i to each process type or sub-type, calculate the fractions of input gas i and by-product gas k formed from gas i that are exhausted from tools with abatement systems based on the numbers of tools with and without abatement systems within each process type or sub-type.

(4) *Method to calculate emissions from fluorinated GHGs that are not tested.* Calculate emissions from consumption of each intermittent low-use fluorinated GHG as defined in § 98.98 of this subpart using the default utilization and by-product formation rates provided in table I–11, I–12, I–13, I–14, or I–15 to this subpart, as applicable, and by using equations I–8A, I–8B, I–9, and I–13 to this section. If a fluorinated GHG was not being used during the stack testing and does not meet the definition of intermittent low-use fluorinated GHG in § 98.98, then you must test the stack systems associated with the use of that fluorinated GHG at a time when that gas is in use at a magnitude that would allow you to determine an emission factor for that gas according to the procedures specified in paragraph (i)(3) of this section.

(5) [Reserved]

■ 24. Amend § 98.94 by:

■ a. Revising paragraph (c) introductory text;

■ b. Adding paragraph (e);

■ c. Revising paragraphs (f)(3), (f)(4) introductory text, (f)(4)(iii), (j)(1) introductory text, (j)(1)(i), (j)(3) introductory text, and (j)(5); and

■ d. Removing and reserving paragraphs (j)(6) and (j)(8)(v).

The revisions and addition read as follows:

§ 98.94 Monitoring and QA/QC requirements.

* * * * *

(c) You must develop apportioning factors for fluorinated GHG and N_2O consumption (including the fraction of gas consumed by process tools connected to abatement systems as in equations I–8A, I–8B, I–9, and I–10 to § 98.93), to use in the equations of this subpart for each input gas i, process sub-type, process type, stack system, and fab as appropriate, using a fab-specific engineering model that is documented in your site GHG Monitoring Plan as required under § 98.3(g)(5). This model must be based on a quantifiable metric, such as wafer passes or wafer starts, or direct measurement of input gas consumption as specified in paragraph (c)(3) of this section. To verify your model, you must demonstrate its precision and accuracy by adhering to the requirements in paragraphs (c)(1) and (2) of this section.

* * * * *

(e) If you use HC fuel CECS purchased and installed on or after January 1, 2025 to control emissions from tools that use either NF_3 as an input gas in remote plasma cleaning processes or F_2 as an input gas in any process, and if you use a value less than 1 for either $a_{F2,j}$ or $a_{NF3,RPC}$ in equation I–9 to § 98.93, you must certify and document that the model for each of the systems for which you are claiming that it does not form CF_4 from F_2 has been tested and verified to produce less than 0.1% CF_4 from F_2 and that each of the systems is installed, operated, and maintained in accordance with the directions of the HC fuel CECS manufacturer. Hydrocarbon-fuel-based combustion emissions control systems include but are not limited to abatement systems as defined in § 98.98 that are hydrocarbon-fuel-based. The rate of conversion from F_2 to CF_4 must be measured using a scientifically sound, industry-accepted method that accounts for dilution through the abatement device, such as EPA 430–R–10–003 (incorporated by reference, see § 98.7), adjusted to calculate the rate of conversion from F_2 to CF_4 rather than the DRE. Either the HC fuel CECS manufacturer or the electronics manufacturer may perform the measurement. The flow rate of F_2 into the tested HC fuel CECS may be metered using a calibrated mass flow controller.

(f) * * *

(3) If you use default destruction and removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i), you must certify and document that the abatement systems at your facility for which you use default destruction or removal efficiency values are specifically designed for fluorinated GHG or N_2O abatement, as applicable, and provide the abatement system manufacturer-verified DRE value that meets (or exceeds) the default destruction or removal efficiency in table I–16 to this subpart for the fluorinated GHG or N_2O. For abatement systems purchased and installed on or after January 1, 2025, you must also certify and document that the abatement system has been tested by the abatement system manufacturer based on the methods specified in paragraph (f)(3)(i) of this section and verified to meet (or exceed) the default destruction or removal efficiency in table I–16 for the fluorinated GHG or N_2O under worst-case flow conditions as defined in paragraph (f)(3)(ii) of this section. If you use a verified destruction and removal efficiency value that is lower than the default in table I–16 to this subpart in your emissions calculations under § 98.93(a), (b), and/or (i), you must certify and document that the abatement systems at your facility for which you use the verified destruction or removal efficiency values are specifically designed for fluorinated GHG or N_2O abatement, as applicable, and provide the abatement system manufacturer-verified DRE value that is lower than the default destruction or removal efficiency in table I–16 for the fluorinated GHG or N_2O. For abatement systems purchased and installed on or after January 1, 2025, you must also certify and document that the abatement system has been tested by the abatement system manufacturer based on the methods specified in paragraph (f)(3)(i) of this section and verified to meet or exceed the destruction or removal efficiency value used for that fluorinated GHG or N_2O under worst-case flow conditions as defined in paragraph (f)(3)(ii) of this section. If you elect to calculate fluorinated GHG emissions using the stack test method under § 98.93(i), you must also certify that you have included and accounted for all abatement systems designed for fluorinated GHG abatement and any respective downtime in your emissions calculations under § 98.93(i)(3).

(i) For purposes of paragraph (f)(3) of this section, destruction and removal efficiencies for abatement systems purchased and installed on or after January 1, 2025, must be measured using a scientifically sound, industry-accepted measurement methodology that accounts for dilution through the abatement system, such as EPA 430–R–10–003 (incorporated by reference, see § 98.7).

(ii) Worst-case flow conditions are defined as the highest total fluorinated GHG or N_2O flows through each model of emissions control systems (gas by gas and process type by process type across the facility) and the highest total flow scenarios (with N_2 dilution accounted for) across the facility during which the abatement system is claimed to be in operational mode.

(4) If you calculate and report controlled emissions using neither the default destruction or removal efficiency values in table I–16 to this subpart nor an abatement system manufacturer-verified lower destruction or removal efficiency value per paragraph (f)(3) of this section, you must use an average of properly measured destruction or removal efficiencies for each gas and process sub-type or process type combination, as applicable, determined in accordance with procedures in paragraphs (f)(4)(i) through (vi) of this section. This includes situations in which your fab employs abatement systems not specifically designed for fluorinated GHG or N_2O abatement or for which your fab operates abatement systems outside the range of parameters specified in the documentation supporting the certified DRE and you elect to reflect emission reductions due to these systems. You must not use a default value from table I–16 to this subpart for any abatement system not specifically designed for fluorinated GHG and N_2O abatement, for any abatement system not certified to meet the default value from table I–16, or for any gas and process type combination for which you have measured the destruction or removal efficiency according to the requirements of paragraphs (f)(4)(i) through (vi) of this section.

* * * * *

(iii) If you elect to take credit for abatement system destruction or removal efficiency before completing testing on 20 percent of the abatement systems for that gas and process sub-type or process type combination, as applicable, you must use default destruction or removal efficiencies or a verified destruction or removal efficiency, if verified at a lower value, for a gas and process type combination. You must not use a default value from table I–16 to this subpart for any abatement system not specifically designed for fluorinated GHG and N_2O abatement, and must not take credit for abatement system destruction or removal efficiency before completing testing on 20 percent of the abatement systems for that gas and process sub-type or process type combination, as applicable. Following testing on 20 percent of abatement systems for that gas and process sub-type or process type combination, you must calculate the average destruction or removal efficiency as the arithmetic mean of all test results for that gas and process sub-type or process type combination, until you have tested at least 30 percent of all abatement systems for each gas and process sub-type or process type combination. After testing at least 30 percent of all systems for a gas and process sub-type or process type combination, you must use the arithmetic mean of the most recent 30 percent of systems tested as the average destruction or removal efficiency. You may include results of testing conducted on or after January 1, 2011 for use in determining the site-specific destruction or removal efficiency for a given gas and process sub-type or process type combination if the testing was conducted in accordance with the requirements of paragraph (f)(4)(i) of this section.

* * * * *

(j) * * *

(1) Stack system testing. Conduct an emissions test for each stack system according to the procedures in paragraphs (j)(1)(i) through (iv) of this section.

(i) You must conduct an emission test during which the fab is operating at a representative operating level, as defined in § 98.98, and with the abatement systems connected to the stack system being tested operating with at least 90-percent uptime, averaged over all abatement systems, during the 8-hour (or longer) period for each stack system, or at no less than 90 percent of the abatement system uptime rate measured over the previous reporting year, averaged over all abatement systems. Hydrocarbon-fuel-based combustion emissions control systems that were purchased and installed on or after January 1, 2025, that are used to control emissions from tools that use either NF_3 in remote plasma cleaning processes or F_2 as an input gas in any process type or sub-type, and that are not certified not to form CF_4, must operate with at least 90-percent uptime during the test.

* * * * *

(3) *Fab-specific fluorinated GHG consumption measurements.* You must determine the amount of each fluorinated GHG consumed by each fab during the sampling period for all process tools connected to the stack systems under § 98.93(i)(3), according to the procedures in paragraphs (j)(3)(i) and (ii) of this section.

* * * * *

(5) *Emissions testing frequency.* You must conduct emissions testing to develop fab-specific emission factors on a frequency according to the procedures in paragraph (j)(5)(i) or (ii) of this section.

(i) *Annual testing.* You must conduct an annual emissions test for each stack system unless you meet the criteria in paragraph (j)(5)(ii) of this section to skip annual testing. Each set of emissions testing for a stack system must be separated by a period of at least 2 months.

(ii) *Criteria to test less frequently.* After the first 3 years of annual testing, you may calculate the relative standard deviation of the emission factors for each fluorinated GHG included in the test and use that analysis to determine the frequency of any future testing. As an alternative, you may conduct all three tests in less than 3 calendar years for purposes of this paragraph (j)(5)(ii), but this does not relieve you of the obligation to conduct subsequent annual testing if you do not meet the criteria to test less frequently. If the criteria specified in paragraphs (j)(5)(ii)(A) and (B) of this section are met, you may use the arithmetic average of the three emission factors for each fluorinated GHG and fluorinated GHG byproduct for the current year and the next 4 years with no further testing unless your fab operations are changed in a way that triggers the re-test criteria in paragraph (j)(8) of this section. In the fifth year following the last stack test included in the previous average, you must test each of the stack systems and repeat the relative standard deviation analysis using the results of the most recent three tests (*i.e.* , the new test and the two previous tests conducted prior to the 4-year period). If the criteria specified in paragraphs (j)(5)(ii)(A) and (B) of this section are not met, you must use the emission factors developed from the most recent testing and continue annual testing. You may conduct more than one test in the same year, but each set of emissions testing for a stack system must be separated by a period of at least 2 months. You may repeat the relative standard deviation analysis using the most recent three tests, including those tests conducted prior to the 4-year period, to determine if you are exempt from testing for the next 4 years.

(A) The relative standard deviation of the total CO_2e emission factors calculated from each of the three tests (expressed as the total CO_2e fluorinated GHG emissions of the fab divided by the total CO_2e fluorinated GHG use of the fab) is less than or equal to 15 percent.

(B) The relative standard deviation for all single fluorinated GHGs that individually accounted for 5 percent or more of CO_2e emissions were less than 20 percent.

* * * * *

■ 25. Amend § 98.96 by:

■ a. Revising paragraphs (c)(1) and (2);

■ b. Adding paragraph (o); and

■ c. Revising paragraphs (p)(2), (q)(2) and (3), (r)(2), (w)(2), (y) introductory text, (y)(1), (y)(2)(i) and (iv), and (y)(4).

The revisions and addition read as follows:

§ 98.96 Data reporting requirements.

* * * * *

(c) * * *

(1) When you use the procedures specified in § 98.93(a), each fluorinated GHG emitted from each process type for which your fab is required to calculate emissions as calculated in equations I–6, I–7, and I–9 to § 98.93.

(2) When you use the procedures specified in § 98.93(a), each fluorinated GHG emitted from each process type or process sub-type as calculated in equations I–8A and I–8B to § 98.93, as applicable.

* * * * *

(o) For all HC fuel CECS that were purchased and installed on or after January 1, 2025, that are used to control emissions from tools that use either NF_3 as an input gas in remote plasma clean processes or F_2 as an input gas in any process type or sub-type and for which you are not calculating emissions under equation I–9 to § 98.93, certification that the rate of conversion from F_2 to CF_4 is <0.1% and that the systems are installed, operated, and maintained in accordance with the directions of the HC fuel CECS manufacturer. Hydrocarbon-fuel-based combustion emissions control systems include but are not limited to abatement systems as defined in § 98.98 that are hydrocarbon-fuel-based. If you make the certification based on your own testing, you must certify that you tested the model of the system according to the requirements specified in § 98.94(e). If you make the certification based on testing by the HC fuel CECS manufacturer, you must provide documentation from the HC fuel CECS manufacturer that the rate of conversion from F_2 to CF_4 is <0.1% when tested according to the requirements specified in § 98.94(e).

(p) * * *

(2) The basis of the destruction or removal efficiency being used (default, manufacturer-verified, or site-specific measurement according to

§ 98.94(f)(4)(i)) for each process sub-type or process type and for each gas.

(q) * * *

(2) If you use default destruction or removal efficiency values in your emissions calculations under § 98.93(a), (b), or (i), certification that the site maintenance plan for abatement systems for which emissions are being reported contains the manufacturer's recommendations and specifications for installation, operation, and maintenance for each abatement system. To use the default or lower manufacturer-verified destruction or removal efficiency values, operation of the abatement system must be within manufacturer's specifications, which may include, for example, specifications on vacuum pumps' purges, fuel and oxidizer settings, supply and exhaust flows and pressures, and utilities to the emissions control equipment including fuel gas flow and pressure, calorific value, and water quality, flow and pressure.

(3) If you use default destruction or removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i), certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG or N_2O abatement, as applicable. You must support this certification by providing abatement system supplier documentation stating that the system was designed for fluorinated GHG or N_2O abatement, as applicable, and supply the destruction or removal efficiency value at which each abatement system is certified for the fluorinated GHG or N_2O abated, as applicable. You may only use the default destruction or removal efficiency value if the abatement system is verified to meet or exceed the destruction or removal efficiency default value in table I–16 to this subpart. If the system is verified at a destruction or removal efficiency value lower than the default value, you may use the verified value.

* * * * *

(r) * * *

(2) Use equation I–28 to this section to calculate total unabated emissions, in metric ton CO_2e, of all fluorinated GHG emitted from electronics manufacturing processes whose emissions of fluorinated GHG you calculated according to the stack testing procedures in § 98.93(i)(3). For each set of processes, use the same input gas consumption (C_{if}), input gas emission factors (EF_{if}), by-product gas emission factors (EF_{kf}), fractions of tools abated (a_{if} and a_{kif}), and destruction efficiencies (d_{if} and d_{ik}) to calculate unabated emissions as you used to calculate emissions.

$$SFGHG = \sum_i \left[\frac{EF_{if}}{(1-(a_{if}*d_{if}))} * C_{if} * GWP_i\right] + \sum_k \left[EF_{kf} * \sum_i \frac{C_{if}}{1-(a_{kif}\bullet d_{ik})} * GWP_k\right] \qquad \text{Eq. I–28}$$

Where:

SFGHG = Total unabated emissions of fluorinated GHG emitted from electronics manufacturing processes in the fab, expressed in metric ton CO_2e for which you calculated total emission according to the procedures in § 98.93(i)(3).

EF_{if} = Emission factor for fluorinated GHG input gas i, emitted from fab f, as calculated in equation I–19 to § 98.93 (kg emitted/kg input gas consumed).

a_{if} = Fraction of fluorinated GHG input gas i used in fab f in tools with abatement systems (expressed as a decimal fraction).

d_{if} = Fraction of fluorinated GHG i destroyed or removed in abatement systems connected to process tools in fab f, as calculated from equation I–24A to § 98.93, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

C_{if} = Total consumption of fluorinated GHG input gas i, of tools vented to stack systems, for fab f, for the reporting year, expressed in metric ton CO_2e, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, emitted from fab f, as calculated in equation I–20 to § 98.93 (kg emitted/kg of all input gases consumed in tools vented to stack systems).

a_{kif} = Fraction of fluorinated GHG by-product gas k emitted in fab f from tools using input gas i with abatement systems (expressed as a decimal fraction), as calculated using equation I–24D to § 98.93.

d_{ik} = Fraction of fluorinated GHG byproduct k destroyed or removed in abatement systems connected to process tools in fab f, as calculated from equation I–24B to § 98.93, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

GWP_i = GWP of emitted fluorinated GHG i from table A–1 to subpart A of this part.

GWP_k = GWP of emitted fluorinated GHG by-product k from table A–1 to subpart A of this part.

i = Fluorinated GHG.

k = Fluorinated GHG by-product.

* * * * *

(w) * * *

(2) An inventory of all stack systems from which process fluorinated GHG are emitted.

* * * * *

(y) If your semiconductor manufacturing facility manufactures wafers greater than 150 mm and emits more than 40,000 metric ton CO_2e of GHG emissions, based on your most recently submitted annual report as required in paragraph (c) of this section, from the electronics manufacturing processes subject to reporting under this subpart, you must prepare and submit a technology assessment report every five years to the Administrator (or an authorized representative) that meets the requirements specified in paragraphs (y)(1) through (6) of this section. Any other semiconductor manufacturing facility may voluntarily submit this report to the Administrator. If your semiconductor manufacturing facility manufactures only 150 mm or smaller wafers, you are not required to prepare and submit a technology assessment report, but you are required to prepare and submit a report if your facility begins manufacturing wafers 200 mm or larger during or before the calendar year preceding the year the technology assessment report is due. If your semiconductor manufacturing facility is no longer required to report to the GHGRP under subpart I due to the cessation of semiconductor manufacturing as described in § 98.2(i)(3), you are not required to submit a technology assessment report.

(1) The first technology assessment report due after January 1, 2025, is due on March 31, 2028, and subsequent reports must be delivered every 5 years no later than March 31 of the year in which it is due.

(2) * * *

(i) It must describe how the gases and technologies used in semiconductor manufacturing using 200 mm and 300 mm wafers in the United States have changed in the past 5 years and whether any of the identified changes are likely to have affected the emissions characteristics of semiconductor manufacturing processes in such a way that the default utilization and by-product formation rates or default destruction or removal efficiency factors of this subpart may need to be updated.

* * * * *

(iv) It must provide any utilization and byproduct formation rates and/or destruction or removal efficiency data that have been collected in the previous 5 years that support the changes in semiconductor manufacturing processes described in the report. Any utilization or byproduct formation rate data submitted must be reported using both of the methods specified in paragraphs (y)(2)(iv)(A) and (B) of this section if multiple fluorinated input gases are used, unless one of the input gases does not have a reference process utilization rate in table I–19 or I–20 to this subpart for the process type and wafer size whose emission factors are being measured, in which case the data must be submitted using the method specified in paragraph (y)(2)(iv)(A) of this section. If only one fluorinated input gas is fed into the process, you must use equations I–29A and I–29B to this section. In addition to using the methods specified in paragraphs (y)(2)(iv)(A) and (B) of this section, you have the option to calculate and report the utilization or byproduct formation rate data using any alternative calculation methodology. The report must include the input gases used and measured, the utilization rates measured, the byproduct formation rates measured, the process type, the process subtype for chamber clean processes, the wafer size, and the methods used for the measurements. The report must also specify the method used to calculate each reported utilization and by-product formation rate, and provide a unique record number for each data set. For any destruction or removal efficiency data submitted, the report must include the input gases used and measured, the destruction and removal efficiency measured, the process type, the methods used for the measurements, and whether the abatement system is specifically designed to abate the gas measured under the operating conditions used for the measurement. If you choose to use an additional alternative calculation methodology to calculate and report the input gas emission factors and by-product formation rates, you must provide a complete, mathematical description of the alternative method used (including the equation used to calculate each reported utilization and by-product formation rate) and include the information in this paragraph (y)(2)(iv).

(A) *All-input gas method.* Use equation I–29A to this section to calculate the input gas emission factor $(1 - U_{ij})$ for each input gas in a single test. If the result of equation I–29A exceeds 0.8 for an F–GHG that contains carbon, you must use equation I–29C to this section to calculate the input gas emission factor for that F–GHG and equation I–29D to this section to calculate the by-product formation rate for that F–GHG from the other input gases. Use equation I–29B to this section to calculate the by-product formation rates from each input gas for F–GHGs that are not input gases. If a test uses a cleaning or etching gas that does not contain carbon in combination with a cleaning or etching gas that does contain carbon and the process chamber is not used to etch or deposit carbon-containing films, you may elect to assign carbon containing by-products only to the carbon-containing input gases. If you choose to assign carbon containing by-products only to carbon-containing input gases, remove the input mass of the non-carbon containing gases from the sum of $Mass_i$ and the sum of $Mass_g$ in equations I–29B and I–29D to this section, respectively.

$$\left(1 - U_{ij}\right) = \frac{(E_i)}{(Mass_i)} \qquad \text{(Eq. I–29A)}$$

Where:

U_{ij} = Process utilization rate for fluorinated GHG i, process type j.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of input gas i fed into the process.

i = Fluorinated GHG.

j = Process type.

$$BEF_{kji} = \frac{(E_k)}{\sum_i Mass_i} \qquad \text{(Eq. I–29B)}$$

Where:

BEF_{kji} = By-product formation rate for gas k from input gas i, for process type j, where gas k is not an input gas.

E_k = The mass emissions of by-product gas k.

$Mass_i$ = The mass of input gas i fed into the process.

i = Fluorinated GHG.

j = Process type.

k = Fluorinated GHG by-product.

$$\left(1 - U_{ij}\right) = 0.8 \qquad \text{(Eq. I–29C)}$$

Where:

U_{ij} = Process utilization rate for fluorinated GHG i, process type j.

$$BEF_{ijg} = \frac{(E_i - 0.8 * Mass_i)}{\sum_g Mass_g} \qquad \text{(Eq. I–29D)}$$

Where:

BEF_{ijg} = By-product formation rate for gas i from input gas g for process type j.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of input gas i fed into the process.

$Mass_g$ = The mass of input gas g fed into the process, where g does not equal input gas i.

i = Fluorinated GHG.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

j = Process type.

(B) *Reference emission factor method.* Calculate the input gas emission factors and by-product formation rates from a test using equations I–30A, I–30B, and I–29B to this section, and table I–19 or I–20 to this subpart. In this case, use equation I–30A to this section to calculate the input gas emission factors and use equation I–30B and I–29B to this section to calculate the by-product formation rates.

$$\left(1-U_{ij}\right)=\left(1-U_{ijr}\right)*\left[\frac{E_i}{\left(Mass_i*\left(1-U_{ijr}\right)+\sum_g Mass_g BEF_{ijgr}\right)}\right] \qquad \text{(Eq. I–30A)}$$

Where:

U_{ij} = Process utilization rate for fluorinated GHG i, process type j.

U_{ijr} = Reference process utilization rate for fluorinated GHG i, process type j, for input gas i, using table I–19 or I–20 to this subpart as appropriate.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of gas i fed into the process.

$Mass_g$ = The mass of input gas g fed into the process, where g does not equal input gas i.

BEF_{ijgr} = Reference by-product formation rate for gas i from input gas g for process type j, using table I–19 or I–20 to this subpart as appropriate.

i = Fluorinated GHG.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

r = Reference data.

$$BEF_{ijg}=BEF_{ijgr}*\left[\frac{E_i}{\left(Mass*\left(1-U_{ijr}\right)+\sum_g Mass_g\, BEF_{ijgr}\right)}\right] \qquad \text{(Eq. I–30B)}$$

Where:

BEF_{ijg} = By-product formation rate for gas i from input gas g for process type j, where gas i is also an input gas.

BEF_{ijgr} = Reference by-product formation rate for gas i from input gas g for process type j from table I–19 or I–20 to this subpart, as appropriate.

U_{ijr} = Reference process utilization rate for fluorinated GHG i, process type j, for input gas i, using table I–19 or I–20 to this subpart, as appropriate.

E_i = The mass emissions of input gas i.

$Mass_i$ = The mass of gas i fed into the process.

$Mass_g$ = The mass of input gas g fed into the process, where g does not equal input gas i.

i = Fluorinated GHG.

j = Process type.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

r = Reference data.

* * * * *

(4) Multiple semiconductor manufacturing facilities may submit a single consolidated technology assessment report as long as the facility identifying information in § 98.3(c)(1) and the certification statement in § 98.3(c)(9) is provided for each facility for which the consolidated report is submitted.

* * * * *

■ 26. Amend § 98.97 by:

■ a. Adding paragraph (b);

■ b. Revising paragraphs (d)(1)(iii), (d)(3), (d)(5)(i), (d)(6) and (7), and (d)(9)(i);

■ c. Removing and reserving paragraph (i)(1); and

■ d. Revising paragraphs (i)(5) and (9) and (k).

The addition and revisions read as follows:

§ 98.97 Records that must be retained.

* * * * *

(b) If you use HC fuel CECS purchased and installed on or after January 1, 2025, to control emissions from tools that use either NF_3 as an input gas in remote plasma cleaning processes or F_2 as an input gas in any process, and if you use a value less than 1 for either $a_{F2,j}$ or $a_{NF3,RPC}$ in equation I–9 to § 98.93, certification and documentation that the model for each of the systems that you claim does not form CF_4 from F_2 has been tested and verified to produce less than 0.1% CF_4 from F_2, and certification that the site maintenance plan includes the HC fuel CECS manufacturer's recommendations and specifications for installation, operation, and maintenance of those systems. If you are relying on your own testing to make the certification that the model produces less than 0.1% CF_4 from F_2, the documentation must include the model tested, the method used to perform the testing (*e.g.,* EPA 430–R–10–003, modified to calculate the formation rate of CF_4 from F_2 rather than the DRE), complete documentation of the results of any initial and subsequent tests, and a final report similar to that specified in EPA 430–R–10–003 (incorporated by reference, see § 98.7), with appropriate adjustments to reflect the measurement of the formation rate of CF_4 from F_2 rather than the DRE. If you are relying on testing by the HC fuel CECS manufacturer to make the certification that the system produces less than 0.1% CF_4 from F_2, the documentation must include the model tested, the method used to perform the testing, and the results of the test.

* * * * *

(d) * * *

(1) * * *

(iii) If you use either default destruction or removal efficiency values or certified destruction or removal efficiency values that are lower than the default values in your emissions calculations under § 98.93(a), (b), and/or (i), certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG and N_2O abatement, as required under § 98.94(f)(3), certification that the site maintenance plan includes the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance, and the certified destruction and removal efficiency values for all applicable abatement systems. For abatement systems purchased and installed on or after January 1, 2025, also include records of the method used to measure the destruction and removal efficiency values.

* * * * *

(3) Where either the default destruction or removal efficiency value or a certified destruction or removal efficiency value that is lower than the default is used, documentation from the abatement system supplier describing the equipment's designed purpose and emission control capabilities for fluorinated GHG and N_2O.

* * * * *

(5) * * *

(i) The number of abatement systems of each manufacturer, and model numbers, and the manufacturer's certified fluorinated GHG and N_2O destruction or removal efficiency, if any.

* * * * *

(6) Records of all inputs and results of calculations made accounting for the uptime of abatement systems used during the reporting year, in accordance with equations I–15 or I–23 to § 98.93, as applicable. The inputs should

include an indication of whether each value for destruction or removal efficiency is a default value, lower manufacturer-verified value, or a measured site-specific value.

(7) Records of all inputs and results of calculations made to determine the average weighted fraction of each gas destroyed or removed in the abatement systems for each stack system using equations I–24A and I–24B to § 98.93, if applicable. The inputs should include an indication of whether each value for destruction or removal efficiency is a default value, lower manufacturer-verified value, or a measured site-specific value.

* * * * *

(9) * * *

(i) The site maintenance plan for abatement systems must be based on the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance if you use default or lower manufacturer-verified destruction and removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i). If the manufacturer's recommendations and specifications for installation, operation, and maintenance are not available, you cannot use default destruction and removal efficiency values or lower manufacturer-verified value in your emissions calculations under § 98.93(a), (b), and/or (i). If you use an average of properly measured destruction or removal efficiencies determined in accordance with the procedures in § 98.94(f)(4)(i) through (vi), the site maintenance plan for abatement systems must be based on the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance, where available. If you deviate from the manufacturer's recommendations and specifications, you must include documentation that demonstrates how the deviations do not negatively affect the performance or destruction or removal efficiency of the abatement systems.

* * * * *

(i) * * *

(5) The fab-specific emission factor and the calculations and data used to determine the fab-specific emission factor for each fluorinated GHG and by-product, as calculated using equations I–19A, I–19B, I–19C and I–20 to § 98.93(i)(3).

* * * * *

(9) The number of tools vented to each stack system in the fab and all inputs and results for the calculations accounting for the fraction of gas exhausted through abatement systems using equations I–24C and I–24D to § 98.93.

* * * * *

(k) Annual gas consumption for each fluorinated GHG and N_2O as calculated in equation I–11 to § 98.93, including where your fab used less than 50 kg of a particular fluorinated GHG or N_2O used at your facility for which you have not calculated emissions using equations I–6, I–7, I–8A, I–8B, I–9, I–10, I–21, or I–22 to § 98.93, the chemical name of the GHG used, the annual consumption of the gas, and a brief description of its use.

* * * * *

■ 27. Amend § 98.98 by:

■ a. Removing the definition "Fluorinated heat transfer fluids";

■ b. Adding the definition "Hydrocarbon-fuel based combustion emission control systems (HC fuel CECs)" in alphabetical order; and

■ c. Revising the definition "Operational mode".

The revisions and addition read as follows:

§ 98.98 Definitions.

* * * * *

Hydrocarbon-fuel based combustion emission control system (HC fuel CECS) means a hydrocarbon fuel-based combustion device or equipment that is designed to destroy or remove gas emissions in exhaust streams via combustion from one or more electronics manufacturing production processes, and that is connected to manufacturing tools that have the potential to emit F_2 or fluorinated greenhouse gases. HC fuel CECs include both emission control systems that are and are not designed to destroy or remove fluorinated GHGs or N_2O.

* * * * *

Operational mode means the time in which an abatement system is properly installed, maintained, and operated according to the site maintenance plan for abatement systems as required in § 98.94(f)(1) and defined in § 98.97(d)(9). This includes being properly operated within the range of parameters as specified in the site maintenance plan for abatement systems. For abatement systems purchased and installed on or after January 1, 2025, this includes being properly operated within the range of parameters specified in the DRE certification documentation. An abatement system is considered to not be in operational mode when it is not operated and maintained according to the site maintenance plan for abatement systems or, for abatement systems purchased and installed on or after January 1, 2025, not operated within the range of parameters as specified in the DRE certification documentation.

* * * * *

■ 28. Revise table I–1 to subpart I to read as follows:

TABLE I–1 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS FOR MANUFACTURING CAPACITY-BASED THRESHOLD APPLICABILITY DETERMINATION

Product type	Emission factors EF_i							
	CF_4	C_2F_6	CHF_3	c-C_4F_8	C_3F_8	NF_3	SF_6	N_2O
Semiconductors (kg/m^2)	0.9	1.0	0.04	NA	0.05	0.04	0.20	NA
LCD (g/m^2)	0.65	NA	0.0024	0.00	NA	1.29	4.14	17.06
MEMS (kg/m^2)	0.015	NA	NA	0.076	NA	NA	1.86	NA

Notes: NA denotes not applicable based on currently available information.

■ 29. Revise table I–2 to subpart I to read as follows:

TABLE I–2 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS FOR GAS CONSUMPTION-BASED THRESHOLD APPLICABILITY DETERMINATION

	Process gas i	
	Fluorinated GHGs	N_2O
$1-U_i$	0.8	1
BCF_4	0.15	0
BC_2F_6	0.05	0

■ 30. Revise table I–3 to subpart I to read as follows:

TABLE I–3 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS ($1-U_{ij}$) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 150 mm AND 200 mm WAFER SIZES

Process type/sub-type	Process gas i												
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
Etching/Wafer Cleaning													
$1-U_i$	0.73	0.72	0.51	0.13	0.064	0.70	NA	0.14	0.19	0.55	0.083	0.072	NA
BCF_4	NA	0.10	0.085	0.079	0.077	NA	NA	0.11	0.0040	0.13	0.095	NA	NA
BC_2F_6	0.041	NA	0.035	0.025	0.024	0.0034	NA	0.037	0.025	0.11	0.073	0.014	NA
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
$BCHF_3$	0.091	0.047	NA	0.049	NA	NA	NA	0.040	NA	0.0012	0.066	0.0039	NA
Chamber Cleaning													
In situ plasma cleaning													
$1-U_i$	0.92	0.55	NA	NA	NA	NA	0.40	0.10	0.18	NA	NA	NA	0.14
BCF_4	NA	0.19	NA	NA	NA	NA	0.20	0.11	0.14	NA	NA	NA	0.13
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.045
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning													
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	0.028	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	0.015	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	NA	0.5	NA	NA	NA	NA
In situ thermal cleaning													
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; *i.e.,* there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

31. Revise table I–4 to subpart I to read as follows:

TABLE I–4 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS ($1-U_{ij}$) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 300 mm AND 450 mm WAFER SIZE

Process type/sub-type	Process gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
Etching/Wafer Cleaning												
$1-U_i$	0.65	0.80	0.37	0.20	0.30	0.30	0.18	0.16	0.30	0.15	0.10	NA
BCF_4	NA	0.21	0.076	0.060	0.0291	0.21	0.045	0.044	0.033	0.059	0.11	NA
BC_2F_6	0.058	NA	0.058	0.043	0.009	0.018	0.027	0.045	0.041	0.062	0.083	NA
BC_4F_8	0.0046	NA	0.0027	0.054	0.0070	NA	NA	NA	NA	0.0051	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
$BCHF_3$	0.012	NA	NA	0.057	0.016	0.012	0.028	0.023	0.0039	0.017	0.0069	NA
BCH_2F_2	0.005	NA	0.0024	NA	0.0033	NA	0.0021	0.00074	0.000020	0.000030	NA	NA
BCH_3F	0.0061	NA	0.027	0.0036	NA	0.00073	0.0063	0.0080	0.0082	0.00065	NA	NA

TABLE I–4 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 300 mm AND 450 mm WAFER SIZE—Continued

Process type/sub-type	Process gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
Chamber Cleaning												
In situ plasma cleaning												
1–U_i	NA	NA	NA	NA	NA	NA	NA	0.20	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning												
1–U_i	NA	NA	NA	NA	NA	0.063	NA	0.018	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
$BCHF_3$	NA	NA	NA	NA	NA	NA	NA	0.000059	NA	NA	NA	NA
BCH_2F_2	NA	NA	NA	NA	NA	NA	NA	0.00088	NA	NA	NA	NA
BCH_3F	NA	NA	NA	NA	NA	NA	NA	0.0028	NA	NA	NA	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	0.5	NA	NA	NA	NA
In situ thermal cleaning												
1–U_i	NA	NA	NA	NA	NA	NA	NA	0.28	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.010	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; *i.e.*, there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

■ 32. Revise table I–8 to subpart I to read as follows:

TABLE I–8 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–$UN_2O_{,j}$) FOR N_2O UTILIZATION ($UN_2O_{,j}$)

Manufacturing type/process type/wafer size	N_2O
Semiconductor Manufacturing:	
200 mm or Less:	
CVD 1–U_i	1.0
Other Manufacturing Process 1–U_i	1.0
300 mm or greater:	
CVD 1–U_i	0.5
Other Manufacturing Process 1–U_i	1.0
LCD Manufacturing:	
CVD Thin Film Manufacturing 1–U_i	0.63
All other N_2O Processes	1.0

■ 33. Revise table I–11 to subpart I to read as follows:

TABLE I–11 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR USE WITH THE STACK TEST METHOD

[150 mm and 200 mm Wafers]

All processes	Process gas i													
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	NF_3 Remote	SF_6	C_4F_6	C_5F_8	C_4F_8O
1–U_i	0.79	0.55	0.51	0.13	0.064	0.70	0.40	0.12	0.18	0.028	0.58	0.083	0.072	0.14
BCF_4	NA	0.19	0.085	0.079	0.077	NA	0.20	0.11	0.11	0.015	0.13	0.095	NA	0.13
BC_2F_6	0.027	NA	0.035	0.025	0.024	0.0034	NA	0.019	0.0059	NA	0.10	0.073	0.014	0.045
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_5F_8	0.00077	NA	0.0012	NA	NA	NA	NA	0.0043	NA	NA	NA	NA	NA	NA
$BCHF_3$	0.060	0.0020	NA	0.049	NA	NA	NA	0.020	NA	NA	0.0011	0.066	0.0039	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.50	NA	NA	NA	NA

Notes: NA = Not applicable; *i.e.*, there are no applicable emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

■ 34. Revise table I–12 to subpart I to read as follows:

TABLE I–12 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR USE WITH THE STACK TEST METHOD

[300 mm and 450 mm Wafers]

All processes	Process gas i													
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_3F_8 Remote	C_4F_8	NF_3	NF_3 Remote	SF_6	C_4F_6	C_5F_8	C_4F_8O
1–U_i	0.65	0.80	0.37	0.20	0.30	0.30	0.063	0.183	0.19	0.018	0.30	0.15	0.100	NA
BCF_4	NA	0.21	0.076	0.060	0.029	0.21	NA	0.045	0.040	0.037	0.033	0.059	0.109	NA
BC_2F_6	0.058	NA	0.058	0.043	0.0093	0.18	NA	0.027	0.0204	NA	0.041	0.062	0.083	NA
BC_4F_6	0.0083	NA	0.01219	NA	0.001	NA	NA	0.008	NA	NA	NA	NA	NA	NA
BC_4F_8	0.0046	NA	0.00272	0.054	0.007	NA	NA	NA	NA	NA	NA	0.0051	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
BCH_2F_2	0.005	NA	0.0024	NA	0.0033	NA	NA	0.0021	0.00034	0.00088	0.000020	0.000030	NA	NA
BCH_3F	0.0061	NA	0.027	0.0036	NA	0.0007	NA	0.0063	0.0036	0.0028	0.0082	0.00065	NA	NA
$BCHF_3$	0.012	NA	NA	0.057	0.016	0.012	NA	0.028	0.0106	0.000059	0.0039	0.017	0.0069	NA
BF_2	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.50	NA	NA	NA	NA

■ 35. Revise table I–16 to subpart I to read as follows:

TABLE I–16 TO SUBPART I OF PART 98—DEFAULT EMISSION DESTRUCTION OR REMOVAL EFFICIENCY (DRE) FACTORS FOR ELECTRONICS MANUFACTURING

Manufacturing type/process type/gas	Default DRE (%)
MEMS, LCDs, and PV Manufacturing	60
Semiconductor Manufacturing:	
CF_4	87
CH_3F	98
CHF_3	97
CH_2F_2	98
C_4F_8	93
C_4F_8O	93
C_5F_8	97
C_4F_6	95
C_3F_8	98
C_2HF_5	97
C_2F_6	98
SF_6	95
NF_3	96
All other carbon-based fluorinated GHGs used in Semiconductor Manufacturing	60
N_2O Processes.	
CVD and all other N_2O-using processes	60

■ 36. Add table I–18 to subpart I to read as follows:

TABLE I–18 TO SUBPART I OF PART 98—DEFAULT FACTORS FOR GAMMA ($\gamma_{i,p}$ AND $\gamma_{k,i,p}$) FOR SEMICONDUCTOR MANUFACTURING AND FOR MEMS AND PV MANUFACTURING UNDER CERTAIN CONDITIONS * FOR USE WITH THE STACK TESTING METHOD

Process type	In-situ thermal or in-situ plasma cleaning					Remote plasma cleaning		
Gas	CF_4	C_2F_6	c-C_4F_8	NF_3	SF_6	C_3F_8	CF_4	NF_3
If manufacturing wafer sizes ≤200 mm AND manufacturing 300 mm (or greater) wafer sizes								
γ_i	13	9.3	4.7	14	11	NA	NA	5.7
$\gamma_{CF4,i}$	NA	23	6.7	63	8.7	NA	NA	58
$\gamma_{C2F6,i}$	NA	NA	NA	NA	3.4	NA	NA	NA
$\gamma_{CHF3,i}$	NA	NA	NA	NA	NA	NA	NA	0.24
$\gamma_{CH2F2,i}$	NA	NA	NA	NA	NA	NA	NA	111
$\gamma_{CH3F,i}$	NA	NA	NA	NA	NA	NA	NA	33
If manufacturing ≤200 mm OR manufacturing 300 mm (or greater) wafer sizes								
γ_i (≤ 200 mm wafer size)	13	9.3	4.7	2.9	11	NA	NA	1.4

TABLE I–18 TO SUBPART I OF PART 98—DEFAULT FACTORS FOR GAMMA ($\gamma_{i,p}$ AND $\gamma_{k,i,p}$) FOR SEMICONDUCTOR MANUFACTURING AND FOR MEMS AND PV MANUFACTURING UNDER CERTAIN CONDITIONS * FOR USE WITH THE STACK TESTING METHOD—Continued

Process type	In-situ thermal or in-situ plasma cleaning					Remote plasma cleaning		
Gas	CF_4	C_2F_6	c-C_4F_8	NF_3	SF_6	C_3F_8	CF_4	NF_3
$\gamma_{CF4,i}$ (≤200 mm wafer size)	NA	23	6.7	110	8.7	NA	NA	36
$\gamma_{C2F6,i}$ (≤200 mm wafer size)	NA	NA	NA	NA	3.4	NA	NA	NA
γ_i (300 mm wafer size)	NA	NA	NA	26	NA	NA	NA	10
$\gamma_{CF4,i}$ (300 mm wafer size)	NA	NA	NA	17	NA	NA	NA	80
$\gamma_{C2F6,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	NA
$\gamma_{CHF3,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	0.24
$\gamma_{CH2F2,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	111
$\gamma_{CH3F,i}$ (300 mm wafer size)	NA	NA	NA	NA	NA	NA	NA	33

* If you manufacture MEMS or PVs and use semiconductor tools and processes, you may use the corresponding γ in this table. For all other tools and processes, a default γ of 10 must be used.

■ 37. Add table I–19 to subpart I to read as follows:

TABLE I–19 TO SUBPART I OF PART 98—REFERENCE EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 150 MM AND 200 MM WAFER SIZES

Process type/sub-type	Process gas i												
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
Etching/Wafer Cleaning													
1–U_i	0.73	0.46	0.31	0.37	0.064	0.66	NA	0.21	0.20	0.55	0.086	0.072	NA
BCF_4	NA	0.20	0.10	0.031	0.077	NA	NA	0.17	0.0040	0.023	0.0089	NA	NA
BC_2F_6	0.029	NA	NA	NA	NA	NA	NA	0.065	NA	NA	0.045	0.014	NA
BC_4F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_5F_8	NA	NA	NA	NA	NA	NA	NA	0.016	NA	NA	NA	NA	NA
$BCHF_3$	0.13	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0039	NA
Chamber Cleaning													
In situ plasma cleaning													
1–U_i	0.92	0.55	NA	NA	NA	NA	0.40	0.10	0.18	NA	NA	NA	0.14
BCF_4	NA	0.19	NA	NA	NA	NA	0.20	0.11	0.14	NA	NA	NA	0.13
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.045
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning													
1–U_i	NA	NA	NA	NA	NA	NA	NA	NA	0.028	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	0.015	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning													
1–U_i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

■ 38. Add table I–20 to subpart I to read as follows:

TABLE I–20 TO SUBPART I OF PART 98—REFERENCE EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 300 MM WAFER SIZES

Process type/sub-type	Process gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
Etching/Wafer Cleaning												
1–U_i	0.68	0.80	0.35	0.15	0.34	0.30	0.16	0.17	0.28	0.17	0.10	NA
BCF_4	NA	0.21	0.073	0.020	0.038	0.21	0.045	0.035	0.0072	0.034	0.11	NA
BC_2F_6	0.041	NA	0.040	0.0065	0.0064	0.18	0.030	0.038	0.0017	0.025	0.083	NA
BC_4F_6	0.0015	NA	0.00010	NA	0.0010	NA	0.00083	NA	NA	NA	NA	NA
BC_4F_8	0.0051	NA	0.00061	NA	0.0070	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
BC_5F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
$BCHF_3$	0.0056	NA	NA	0.033	0.0049	0.012	0.029	0.0065	0.0012	0.019	0.0069	NA
BCH_2F_2	0.014	NA	0.0026	NA	0.0023	NA	0.0014	0.00086	0.000020	0.000030	NA	NA
BCH_3F	0.00057	NA	0.12	NA	NA	0.00073	NA	NA	0.0082	NA	NA	NA
Chamber Cleaning												
In situ plasma cleaning												
1–U_i	NA	NA	NA	NA	NA	NA	NA	0.20	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning												
1–U_i	NA	NA	NA	NA	NA	0.063	NA	0.018	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.038	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
$BCHF_3$	NA	NA	NA	NA	NA	NA	NA	0.000059	NA	NA	NA	NA
BCH_2F_2	NA	NA	NA	NA	NA	NA	NA	0.0016	NA	NA	NA	NA
BCH_3F	NA	NA	NA	NA	NA	NA	NA	0.0028	NA	NA	NA	NA
In situ thermal cleaning												
1–U_i	NA	NA	NA	NA	NA	NA	NA	0.28	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.010	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

■ 39. Add table I–21 to subpart I to read as follows:

TABLE I–21 TO SUBPART I OF PART 98—EXAMPLES OF FLUORINATED GHGS USED BY THE ELECTRONICS INDUSTRY

Product type	Fluorinated GHGs used during manufacture
Electronics	CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF_6, and fluorinated HTFs (CF_3-(O-CF(CF_3)-CF_2)n-(O-CF_2)m-O-CF_3, C_nF_{2n+2}, $C_nF_{2n+1}(O)C_mF_{2m+1}$, $C_nF_{2n}O$, $(C_nF_{2n+1})_{3N}$).

Subpart N—Glass Production

■ 40. Revise and republish § 98.146 to read as follows:

§ 98.146 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under § 98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) through (3) of this section:

(1) Annual quantity of each carbonate-based raw material (tons) charged to each continuous glass melting furnace and for all furnaces combined.

(2) Annual quantity of glass produced (tons), by glass type, from each continuous glass melting furnace and from all furnaces combined.

(3) Annual quantity (tons), by glass type, of recycled scrap glass (cullet) charged to each continuous glass melting furnace and for all furnaces combined.

(b) If a CEMS is not used to determine CO_2 emissions from continuous glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in § 98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (9) of this section:

(1) Annual process emissions of CO_2 (metric tons) for each continuous glass melting furnace and for all furnaces combined.

(2) Annual quantity of each carbonate-based raw material charged (tons) to all furnaces combined.

(3) Annual quantity of glass produced (tons), by glass type, from each continuous glass melting furnace and from all furnaces combined.

(4) Annual quantity (tons), by glass type, of recycled scrap glass (cullet) charged to each continuous glass melting furnace and for all furnaces combined.

(5) Results of all tests, if applicable, used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, as specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(6) [Reserved]

(7) Method used to determine decimal fraction of calcination, unless you used the default value of 1.0.

(8) Total number of continuous glass melting furnaces.

(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials, recycled scrap glass (cullet), or mass fraction of the carbonate-based minerals for any continuous glass melting furnace (months).

■ 41. Amend § 98.147 by revising and republishing paragraphs (a) and (b) to read as follows:

§ 98.147 Records that must be retained.

* * * * *

(a) If a CEMS is used to measure emissions, then you must retain the records required under § 98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) through (3) of this section:

(1) Monthly glass production rate for each continuous glass melting furnace, by glass type (tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (tons).

(3) Monthly amount (tons) of recycled scrap glass (cullet) charged to each continuous glass melting furnace, by glass type.

(b) If process CO_2 emissions are calculated according to the procedures specified in § 98.143(b), you must retain the records in paragraphs (b)(1) through (6) of this section.

(1) Monthly glass production rate for each continuous glass melting furnace, by glass type (tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (tons).

(3) Monthly amount (tons) of recycled scrap glass (cullet) charged to each continuous glass melting furnace, by glass type.

(4) Data on carbonate-based mineral mass fractions provided by the raw material supplier for all raw materials consumed annually and included in calculating process emissions in equation N–1 to § 98.143, if applicable.

(5) Results of all tests, if applicable, used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, including the data specified in paragraphs (b)(5)(i) through (v) of this section.

(i) Date of test.

(ii) Method(s), and any variations of the methods, used in the analyses.

(iii) Mass fraction of each sample analyzed.

(iv) Relevant calibration data for the instrument(s) used in the analyses.

(v) Name and address of laboratory that conducted the tests.

(6) The decimal fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO_2.

* * * * *

Subpart P—Hydrogen Production

■ 42. Revise § 98.160 to read as follows:

§ 98.160 Definition of the source category.

(a) A hydrogen production source category consists of facilities that produce hydrogen gas as a product.

(b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks except the processes listed in paragraph (b)(1) or (2) of this section.

(1) Any process unit for which emissions are reported under another subpart of this part. This includes, but is not necessarily limited to:

(i) Ammonia production units for which emissions are reported under subpart G.

(ii) Catalytic reforming units at petroleum refineries that transform naphtha into higher octane aromatics for which emissions are reported under subpart Y.

(iii) Petrochemical process units for which emissions are reported under subpart X.

(2) Any process unit that only separates out diatomic hydrogen from a gaseous mixture and is not associated with a unit that produces hydrogen created by transformation of one or more feedstocks, other than those listed in paragraph (b)(1) of this section.

(c) This source category includes the process units that produce hydrogen and stationary combustion units directly associated with hydrogen production (*e.g.* , reforming furnace and hydrogen production process unit heater).

■ 43. Amend § 98.162 by revising paragraph (a) to read as follows:

§ 98.162 GHGs to report.

* * * * *

(a) CO_2 emissions from each hydrogen production process unit, including fuel combustion emissions accounted for in the calculation methodologies in § 98.163.

* * * * *

■ 44. Amend § 98.163 by revising the introductory text, paragraph (b) introductory text, and paragraph (c) to read as follows:

§ 98.163 Calculating GHG emissions.

You must calculate and report the annual CO_2 emissions from each hydrogen production process unit using the procedures specified in paragraphs (a) through (c) of this section, as applicable.

* * * * *

(b) Fuel and feedstock material balance approach. Calculate and report CO_2 emissions as the sum of the annual emissions associated with each fuel and feedstock used for each hydrogen production process unit by following paragraphs (b)(1) through (3) of this section. The carbon content and molecular weight shall be obtained from the analyses conducted in accordance with § 98.164(b)(2), (3), or (4), as applicable, or from the missing data procedures in § 98.165. If the analyses are performed annually, then the annual value shall be used as the monthly average. If the analyses are performed more frequently than monthly, use the arithmetic average of values obtained during the month as the monthly average.

* * * * *

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, then the owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part. If GHG emissions from a hydrogen production process unit using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part does not include combustion emissions from the hydrogen production unit (*i.e.* , the hydrogen production unit has separate stacks for process and combustion emissions), then the calculation methodology in paragraph (b) of this section shall be used considering only fuel inputs to calculate and report CO_2 emissions from fuel combustion related to the hydrogen production unit.

■ 45. Amend § 98.164 by:

■ a. Revising the introductory text, paragraphs (b)(2) through (4), and (b)(5) introductory text; and

■ b. Adding paragraphs (b)(5)(xix) and (c).

The revisions and additions read as follows:

§ 98.164 Monitoring and QA/QC requirements.

The GHG emissions data for hydrogen production process units must be quality-assured as specified in paragraph (a) or (b) of this section, as appropriate for each process unit, except as provided in paragraph (c) of this section:

* * * * *

(b) * * *

(2) Determine the carbon content and the molecular weight annually of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (*e.g.,* natural gas) according to paragraph (b)(5) of this section. For gaseous fuels and feedstocks that have a maximum product specification for carbon content less than or equal to 0.00002 kg carbon per kg of gaseous fuel or feedstock, you may instead determine the carbon content and the molecular weight annually using the product specification's maximum carbon content and molecular weight. For other gaseous fuels and feedstocks (*e.g.,* biogas, refinery gas, or process gas), sample and analyze no less frequently than weekly to determine the carbon content and molecular weight of the fuel and feedstock according to paragraph (b)(5) of this section.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least monthly, except annually for standard liquid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for liquid fuels and feedstocks delivered by bulk transport (*e.g.,* by truck or rail) according to paragraph (b)(5) of this section. For liquid fuels and feedstocks that have a maximum product specification for carbon content less than or equal to 0.00006 kg carbon per gallon of liquid fuel or feedstock, you may instead determine the carbon content annually using the product specification's maximum carbon content.

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least monthly, except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels and feedstocks delivered by bulk transport (*e.g.,* by truck or rail) according to paragraph (b)(5) of this section.

(5) Except as provided in paragraphs (b)(2) and (3) of this section for fuels and feedstocks with a carbon content below the specified levels, you must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks. Alternatively, you may use the results of chromatographic analysis of the fuel and feedstock, provided that the chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the chromatograph are documented in the written monitoring plan for the unit under § 98.3(g)(5).

* * * * *

(xix) For fuels and feedstocks with a carbon content below the specified levels in paragraphs (b)(2) and (3) of this section, if the methods listed in paragraphs (b)(5)(i) through (xviii) of this section are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe, you may use modifications of the methods listed in paragraphs (b)(5)(i) through (xviii) or use other methods that are applicable to your fuel or feedstock.

(c) You may use best available monitoring methods as specified in paragraph (c)(2) of this section for measuring the fuel used by each stationary combustion unit directly associated with hydrogen production (*e.g.,* reforming furnace and hydrogen production process unit heater) that meets the criteria specified in paragraph (c)(1) of this section. Eligibility to use best available monitoring methods ends upon the completion of any planned process unit or equipment shutdown after January 1, 2025.

(1) To be eligible to use best available monitoring methods, you must meet all criteria in paragraphs (c)(1)(i) through (iv) of this section.

(i) The stationary combustion unit must be directly associated with hydrogen production (*e.g.,* reforming furnace and hydrogen production process unit heater).

(ii) A measurement device meeting the requirements in paragraph (b)(1) of this section is not installed to measure the fuel used by each stationary combustion unit as of January 1, 2025.

(iii) The hydrogen production unit and associated stationary combustion unit are operated continuously.

(iv) Installation of a measurement device to measure the fuel used by each stationary combustion unit that meets the requirements in paragraph (b)(1) of this section must require a planned process equipment or unit shutdown or can only be done through a hot tap.

(2) Best available monitoring methods means any of the following methods:

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

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

■ 46. Revise § 98.166 to read as follows:

§ 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 hydrogen production process unit:

(a) The unit identification number.

(b) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under § 98.36 for the Tier 4 Calculation Methodology. If the CEMS measures emissions from either a common stack for multiple hydrogen production units or a common stack for hydrogen production unit(s) and other source(s), you must also report the estimated decimal fraction of the total annual CO_2 emissions attributable to this hydrogen production process unit (estimated using engineering estimates or best available data).

(c) If a material balance is used to calculate emissions using equations P–1 through P–3 to § 98.163, as applicable, report the total annual CO_2 emissions (metric tons) and the name and annual quantity (metric tons) of each carbon-containing fuel and feedstock.

(d) The information specified in paragraphs (d)(1) through (10):

(1) The type of hydrogen production unit (steam methane reformer (SMR) only, SMR followed by water gas shift reaction (WGS), partial oxidation (POX) only, POX followed by WGS, autothermal reforming only, autothermal reforming followed by WGS, water electrolysis, brine electrolysis, other (specify)).

(2) The type of hydrogen purification method (pressure swing adsorption, amine adsorption, membrane separation, other (specify), none).

(3) Annual quantity of hydrogen produced by reforming, gasification, oxidation, reaction, or other transformation of feedstocks (metric tons).

(4) Annual quantity of hydrogen that is purified only (metric tons). This quantity may be assumed to be equal to the annual quantity of hydrogen in the feedstocks to the hydrogen production unit.

(5) Annual quantity of ammonia intentionally produced as a desired product, if applicable (metric tons).

(6) Quantity of CO_2 collected and transferred off site in either gas, liquid, or solid forms, following the requirements of subpart PP of this part.

(7) Annual quantity of carbon other than CO_2 or methanol collected and transferred off site or transferred to a separate process unit within the facility for which GHG emissions associated with this carbon is being reported under other provisions of this part, in either gas, liquid, or solid forms (metric tons carbon).

(8) Annual quantity of methanol intentionally produced as a desired product, if applicable, (metric tons) for each process unit.

(9) Annual net quantity of steam consumed by the unit, (metric tons). Include steam purchased or produced outside of the hydrogen production unit. If the hydrogen production unit is a net producer of steam, enter the annual net quantity of steam consumed by the unit as a negative value.

(10) An indication (yes or no) if best available monitoring methods were used, in accordance with § 98.164(c), to determine fuel flow for each stationary combustion unit directly associated with hydrogen production (*e.g.,* reforming furnace and hydrogen production process unit heater). If yes, report:

(i) The beginning date of using best available monitoring methods, in accordance with § 98.164(c), to determine fuel flow for each stationary combustion unit directly associated with hydrogen production (*e.g.,* reforming furnace and hydrogen production process unit heater).

(ii) The anticipated or actual end date of using best available monitoring methods, as applicable, in accordance with § 98.164(c), to determine fuel flow for each stationary combustion unit directly associated with hydrogen production (*e.g.,* reforming furnace and hydrogen production process unit heater).

■ 47. Amend § 98.167 by:

■ a. Revising paragraphs (a) and (b);

■ b. Removing and reserving paragraph (c); and

■ c. Revising paragraphs (d) and (e) introductory text.

The revisions read as follows:

§ 98.167 Records that must be retained.

* * * * *

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37, and, if the CEMS measures emissions from a common stack for multiple hydrogen production units or emissions from a common stack for hydrogen production unit(s) and other source(s), records used to estimate the decimal fraction of the total annual CO_2 emissions from the CEMS monitoring location attributable to each hydrogen production unit.

(b) You must retain records of all analyses and calculations conducted to determine the values reported in § 98.166(b).

* * * * *

(d) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel and feedstock usage in § 98.163(b), including, but not limited to, calibration of weighing equipment, fuel and feedstock flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(e) The applicable verification software records as identified in this paragraph (e). You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (e)(1) through (12) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (e)(1) through (12) of this section for each hydrogen production unit.

* * * * *

Subpart Q—Iron and Steel Production

■ 48. Amend § 98.173 by revising equation Q–5 in paragraph (b)(1)(v) to read as follows:

§ 98.173 Calculating GHG emissions.

* * * * *

(b) * * *

(1) * * *

(v) * * *

$$CO_2 = \frac{44}{12} * \Big[(\text{Iron}) * (C_{\text{iron}}) + (\text{Scrap}) * (C_{\text{scrap}}) + (\text{Flux}) * (C_{\text{Flux}}) + (\text{Electrode}) * (C_{\text{Electrode}}) + (\text{Carbon}) * (C_{\text{Carbon}}) - (\text{Steel}) * (C_{\text{Steel}}) + (F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 - (\text{Slag}) * (C_{\text{Slag}}) - (R) * (C_R)\Big] \quad \text{(Eq. Q–5)}$$

* * * * *

■ 49. Amend § 98.174 by:

■ a. Revising paragraph (b)(2) introductory text;

■ b. Redesignating paragraph (b)(2)(vi) as paragraph (b)(2)(vii); and

■ c. Adding new paragraph (b)(2)(vi).

The revision and addition read as follows:

§ 98.174 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(2) Except as provided in paragraph (b)(4) of this section, determine the carbon content of each process input and output annually for use in the applicable equations in § 98.173(b)(1) based on analyses provided by the supplier, analyses provided by material recyclers who manage process outputs for sale or use by other industries, or by the average carbon content determined by collecting and analyzing at least three samples each year using the standard methods specified in paragraphs (b)(2)(i) through (vii) of this section as applicable.

* * * * *

(vi) ASTM E415–17, Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry (incorporated by reference, see § 98.7) as applicable for steel.

* * * * *

■ 50. Amend § 98.176 by revising paragraphs (e)(2) and adding paragraph (g) to read as follows:

§ 98.176 Data reporting requirements.

* * * * *

(e) * * *

(2) Whether the carbon content was determined from information from the supplier, material recycler, or by laboratory analysis, and if by laboratory analysis, the method used in § 98.174(b)(2).

* * * * *

(g) For each unit, the type of unit, the annual production capacity, and annual operating hours.

* * * * *

Subpart S—Lime Manufacturing

■ 51. Amend § 98.193 by revising equation S–4 in paragraph (b)(2)(iv) to read as follows:

§ 98.193 Calculating GHG emissions.

* * * * *

(b) * * *

(2) * * *

(iv) * * *

$$E_{CO2,net} = \sum_{i=1}^{t} \sum_{n=1}^{12} (EF_{LIME,i,n} * M_{LIME,i,n}) + \sum_{i=1}^{b} \sum_{n=1}^{12} (EF_{LKD,i,n} * M_{LKD,i,n}) + \sum_{i=1}^{z} E_{waste,i} \quad \text{(Eq. S–4)}$$

* * * * *

■ 52. Amend § 98.196 by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraphs (a)(9) through (14);

■ c. Revising paragraphs (b) introductory text and (b)(17); and

■ d. Adding paragraphs (b)(22) and (23).

The revisions and additions read as follows:

§ 98.196 Data reporting requirements.

* * * * *

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by § 98.36 and the information listed in paragraphs (a)(1) through (14) of this section.

* * * * *

(9) Annual arithmetic average of calcium oxide content for each type of lime product produced (metric tons CaO/metric ton lime).

(10) Annual arithmetic average of magnesium oxide content for each type of lime product produced (metric tons MgO/metric ton lime).

(11) Annual arithmetic average of calcium oxide content for each type of calcined lime byproduct/waste sold (metric tons CaO/metric ton lime).

(12) Annual arithmetic average of magnesium oxide content for each type of calcined lime byproduct/waste sold (metric tons MgO/metric ton lime).

(13) Annual arithmetic average of calcium oxide content for each type of calcined lime byproduct/waste not sold (metric tons CaO/metric ton lime).

(14) Annual arithmetic average of magnesium oxide content for each type of calcined lime byproduct/waste not sold (metric tons MgO/metric ton lime)

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in paragraphs (b)(1) through (23) of this section.

* * * * *

(17) Indicate whether CO_2 was captured and used on-site (*e.g.,* for use in a purification process, the manufacture of another product). If CO_2 was captured and used on-site, provide the information in paragraphs (b)(17)(i) and (ii) of this section.

(i) The annual amount of CO_2 captured for use in all on-site processes.

(ii) The method used to determine the amount of CO_2 captured.

* * * * *

(22) Annual average results of chemical composition analysis of all lime byproducts or wastes not sold.

(23) Annual quantity (tons) of all lime byproducts or wastes not sold.

Subpart U—Miscellaneous Uses of Carbonate

■ 53. Amend § 98.210 by revising paragraph (b) to read as follows:

§ 98.210 Definition of the source category.

* * * * *

(b) This source category does not include equipment that uses carbonates or carbonate containing minerals that are consumed in the production of cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, zinc, or ceramics.

* * * * *

Subpart X-Petrochemical Production

■ 54. Amend § 98.243 by revising paragraphs (b)(3) and (d)(5) to read as follows:

§ 98.243 Calculating GHG emissions.

* * * * *

(b) * * *

(3) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b).

* * * * *

(d) * * *

(5) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in § 98.253(b).

■ 55. Amend § 98.244 by revising paragraph (b)(4)(iii) to read as follows:

§ 98.244 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(4) * * *

(iii) ASTM D2505–88 (Reapproved 2004)e1 (incorporated by reference, see § 98.7).

* * * * *

■ 56. Amend § 98.246 by revising paragraphs (a) introductory text, (a)(2), (5), (13) and (15), (b)(7) and (8), and (c) to read as follows:

§ 98.246 Data reporting requirements.

* * * * *

(a) If you use the mass balance methodology in § 98.243(c), you must report the information specified in paragraphs (a)(1) through (15) of this section for each type of petrochemical produced, reported by process unit.

* * * * *

(2) The type of petrochemical produced.

* * * * *

(5) Annual quantity of each type of petrochemical produced from each process unit (metric tons). If you are electing to consider the petrochemical process unit to be the entire integrated ethylene dichloride/vinyl chloride monomer process, the portion of the total amount of ethylene dichloride (EDC) produced that is used in vinyl chloride monomer (VCM) production may be a measured quantity or an estimate that is based on process knowledge and best available data. The portion of the total amount of EDC produced that is not utilized in VCM production must be measured in accordance with § 98.244(b)(2) or (3). Sum the amount of EDC used in the production of VCM plus the amount of separate EDC product to report as the total quantity of EDC petrochemical from an integrated EDC/VCM petrochemical process unit.

* * * * *

(13) Name and annual quantity (in metric tons) of each product included in equations X–1, X–2, and X–3 to § 98.243. If you are electing to consider the petrochemical process unit to be the entire integrated ethylene dichloride/vinyl chloride monomer process, the reported quantity of EDC product should include only that which was not used in the VCM process.

* * * * *

(15) For each gaseous feedstock or product for which the volume was used in equation X–1 to § 98.243, report the annual average molecular weight of the measurements or determinations, conducted according to § 98.243(c)(3) or (4). Report the annual average molecular weight in units of kg per kg mole.

(b) * * *

(7) Information listed in § 98.256(e) for each flare that burns process off-gas. Additionally, provide estimates based on engineering judgment of the fractions of the total CO_2, CH_4 and N_2O emissions that are attributable to combustion of off-gas from the petrochemical process unit(s) served by the flare.

(8) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

* * * * *

(c) If you comply with the combustion methodology specified in § 98.243(d), you must report under this subpart the information listed in paragraphs (c)(1) through (6) of this section.

(1) The ethylene process unit ID or other appropriate descriptor.

(2) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), except flares, the relevant information listed in § 98.36 for the applicable Tier methodology. For each stationary combustion unit or group of units (as applicable) that burns ethylene process off-gas, provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the ethylene process unit.

(3) Information listed in § 98.256(e) for each flare that burns ethylene process off-gas. Additionally, provide estimates based on engineering judgment of the fractions of the total CO_2, CH_4 and N_2O emissions that are attributable to combustion of off-gas from the ethylene process unit(s) served by the flare.

(4) Name and annual quantity of each carbon-containing feedstock (metric tons).

(5) Annual quantity of ethylene produced from each process unit (metric tons).

(6) Name and annual quantity (in metric tons) of each product produced in each process unit.

Subpart Y—Petroleum Refineries

■ 57. Amend § 98.250 by revising paragraph (c) to read as follows:

§ 98.250 Definition of source category.

* * * * *

(c) This source category consists of the following sources at petroleum refineries: Catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming 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; and sulfur recovery plants.

§ 98.252 [Amended]

■ 58. Amend § 98.252 by removing and reserving paragraphs (e) and (i).

■ 59. Amend § 98.253 by:

■ a. Revising the introductory text of paragraphs (b) and (c);

■ b. Revising and republishing paragraphs (c)(4) and (5);

■ c. Revising paragraph (e) introductory text;

■ d. Removing and reserving paragraph (g); and

■ e. Revising and republishing paragraphs (i)(2) and (5).

The revisions read as follows:

§ 98.253 Calculating GHG emissions.

* * * * *

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (3) of this section. All gas discharged through the flare stack must be included in the flare

GHG emissions calculations with the exception of the following, which may be excluded as applicable: gas used for the flare pilots, and if using the calculation method in paragraph (b)(1)(iii) of this section, the gas released during start-up, shutdown, or malfunction events of 500,000 scf/day or less.

* * * * *

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions from coke burn-off using the applicable methods described in paragraphs (c)(1) through (5) of this section.

* * * * *

(4) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or equation Y–9 to this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1}\right) \qquad \text{(Eq. Y–9)}$$

Where:

CH_4 = Annual methane emissions from coke burn-off (metric tons CH4/year).

CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), or (e)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from table C–1 to subpart C of this part (kg CO_2/MMBtu).

EmF_2 = Default CH_4 emission factor for ‘‘PetroleumProducts’’ from table C–2 to subpart C of this part (kg CH_4/MMBtu).

(5) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or equation Y–10 to this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1}\right) \qquad \text{(Eq. Y–10)}$$

Where:

N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O/year).

CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), or (e)(2) of this section, as applicable (metric tons/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from table C–1 to subpart C of this part (kg CO_2/MMBtu).

EmF_3 = Default N_2O emission factor for ‘‘PetroleumProducts’’ from table C–2 to subpart C of this part (kg N_2O/MMBtu).

* * * * *

(e) For catalytic reforming units, calculate the CO_2 emissions from coke burn-off using the applicable methods described in paragraphs (e)(1) through (3) of this section and calculate the CH_4 and N_2O emissions using the methods described in paragraphs (c)(4) and (5) of this section, respectively.

* * * * *

(i) * * *

(2) Determine the typical mass of water in the delayed coking unit vessel at the end of the cooling cycle prior to venting to the atmosphere using equation Y–18b to this section.

$$M_{water} = \rho_{water} \times \left((H_{water}) \times \frac{\pi \times D^2}{4} - \frac{f_{coke} \times M_{coke}}{\rho_{particle}}\right) \qquad \text{(Eq. Y–18b)}$$

Where:

M_{water} = Mass of water in the delayed coking unit vessel at the end of the cooling cycle just prior to atmospheric venting or draining (metric tons/cycle).

ρ_{water} = Density of water at average temperature of the delayed coking unit vessel at the end of the cooling cycle just prior to atmospheric venting (metric tons per cubic feet; mt/ft^3). Use the default value of 0.0270 mt/ft^3.

H_{water} = Typical distance from the bottom of the coking unit vessel to the top of the water level at the end of the cooling cycle just prior to atmospheric venting or draining (feet) from company records or engineering estimates.

f_{coke} = Fraction of the coke-filled bed that is covered by water at the end of the cooling cycle just prior to atmospheric venting or draining. Use 1 if the water fully covers coke-filled portion of the coke drum.

M_{coke} = Typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle (metric tons/cycle) as determined in paragraph (i)(1) of this section.

$\rho_{particle}$ = Particle density of coke (metric tons per cubic feet; mt/ft^3). Use the default value of 0.0382 mt/ft^3.

D = Diameter of delayed coking unit vessel (feet).

* * * * *

(5) Calculate the CH_4 emissions from decoking operations at each delayed coking unit using equation Y–18f to this section.

$$CH_4 = M_{steam} \times EmF_{DCU} \times N \times 0.001 \qquad \text{(Eq. Y–18f)}$$

Where:

CH_4 = Annual methane emissions from the delayed coking unit decoking operations (metric ton/year).

M_{steam} = Mass of steam generated and released per decoking cycle (metric tons/cycle) as determined in paragraph (i)(4) of this section.

EmF_{DCU} = Methane emission factor for delayed coking unit (kilograms CH_4 per metric ton of steam; kg CH_4/mt steam) from unit-specific measurement data. If you do not have unit-specific measurement data, use the default value of 7.9 kg CH_4/metric ton steam.

N = Cumulative number of decoking cycles (or coke-cutting cycles) for all delayed coking unit vessels associated with the delayed coking unit during the year.

0.001 = Conversion factor (metric ton/kg).

* * * * *

■ 60. Amend § 98.254 by:

■ a. Revising the introductory text of paragraphs (d) and (e); and

■ b. Removing and reserving paragraphs (h) and (i).

The revisions read as follows:

§ 98.254 Monitoring and QA/QC requirements.

* * * * *

(d) Except as provided in paragraph (g) of this section, determine gas composition and, if required, average molecular weight of the gas using any of the following methods. Alternatively, the results of chromatographic or direct mass spectrometer analysis of the gas may be used, provided that the gas chromatograph or mass spectrometer is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph or mass spectrometer are documented in the written Monitoring Plan for the unit under § 98.3(g)(5).

* * * * *

(e) Determine flare gas higher heating value using any of the following methods. Alternatively, the results of chromatographic analysis of the gas may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in the written Monitoring Plan for the unit under § 98.3(g)(5).

* * * * *

§ 98.255 [Amended]

■ 61. Amend § 98.255 by removing and reserving paragraph (d).

■ 62. Amend § 98.256 by:

■ a. Removing and reserving paragraphs (b) and (i);

■ b. Adding paragraph (j)(2); and

■ c. Revising paragraph (k)(6).

The addition and revision read as follows:

§ 98.256 Data reporting requirements.

* * * * *

(j) * * *

(2) Maximum rated throughput of the unit, in metric tons asphalt/stream day.

* * * * *

(k) * * *

(6) The basis for the typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle (mass measurements from company records or calculated using equation Y–18a to § 98.253). If you use mass measurements from company records to determine the typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle, you must also report:

(i) Internal height of delayed coking unit vessel (feet) for each delayed coking unit.

(ii) Typical distance from the top of the delayed coking unit vessel to the top of the coke bed (*i.e.* , coke drum outage) at the end of the coking cycle (feet) from company records or engineering estimates for each delayed coking unit.

* * * * *

■ 63. Amend § 98.257 by:

■ a. Revising paragraphs (b)(16) through (19);

■ b. Removing and reserving paragraphs (b)(27) through (31);

■ c. Revising paragraphs (b)(45), (46), and (53); and

■ d. Removing and reserving paragraphs (b)(54) through (56).

The revisions read as follows:

§ 98.257 Records that must be retained.

* * * * *

(b) * * *

(16) Value of unit-specific CH_4 emission factor, including the units of measure, for each catalytic cracking unit, traditional fluid coking unit, and catalytic reforming unit (calculation method in § 98.253(c)(4)).

(17) Annual activity data (*e.g.* , input or product rate), including the units of measure, in units of measure consistent with the emission factor, for each catalytic cracking unit, traditional fluid coking unit, and catalytic reforming unit (calculation method in § 98.253(c)(4)).

(18) Value of unit-specific N_2O emission factor, including the units of measure, for each catalytic cracking unit, traditional fluid coking unit, and catalytic reforming unit (calculation method in § 98.253(c)(5)).

(19) Annual activity data (*e.g.* , input or product rate), including the units of measure, in units of measure consistent with the emission factor, for each catalytic cracking unit, traditional fluid coking unit, and catalytic reforming unit (calculation method in § 98.253(c)(5)).

* * * * *

(45) Mass of water in the delayed coking unit vessel at the end of the cooling cycle prior to atmospheric venting or draining (metric ton/cycle) (equations Y–18b and Y–18e to § 98.253) for each delayed coking unit.

(46) Typical distance from the bottom of the coking unit vessel to the top of the water level at the end of the cooling cycle just prior to atmospheric venting or draining (feet) from company records or engineering estimates (equation Y–18b to § 98.253) for each delayed coking unit.

* * * * *

(53) Fraction of the coke-filled bed that is covered by water at the end of the cooling cycle just prior to atmospheric venting or draining (equation Y–18b to § 98.253) for each delayed coking unit.

* * * * *

Subpart AA—Pulp and Paper Manufacturing

■ 64. Revise and republish § 98.273 to read as follows:

§ 98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO_2, biogenic CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (a)(1) through (4) of this section. CH4 and N2O emissions must be calculated as the sum of emissions from combustion of fuels and combustion of biomass in spent liquor solids.

(1) Calculate CO_2 emissions from fuel combustion using direct measurement of fuels consumed and default emissions factors according to the Tier 1 methodology for stationary combustion sources in § 98.33(a)(1). Tiers 2 or 3 from § 98.33(a)(2) or (3) may be used to calculate CO_2 emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate CH_4 and N_2O emissions from fuel combustion using direct measurement of fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c).

(3) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default emissions factors, according to equation AA–1 to this section:

$$\mathrm{CO_2, CH_4, or\ N_2O\ from\ biomass} = (0.90718) * \mathrm{Solids} * \mathrm{HHV} * \mathrm{EF} \qquad \text{(Eq. AA–1)}$$

Where:

CO_2, CH_4, or N_2O, from Biomass = Biogenic CO_2 emissions or emissions of CH_4 or N_2O from spent liquor solids combustion (metric tons per year).

Solids = Mass of spent liquor solids combusted (short tons per year) determined according to § 98.274(b).
HHV = Annual high heat value of the spent liquor solids (mmBtu per kilogram) determined according to § 98.274(b).
EF = Default emission factor for CO_2, CH_4, or N_2O, from table AA–1 to this subpart (kg CO_2, CH_4, or N_2O per mmBtu).
0.90718 = Conversion factor from short tons to metric tons.

(4) Calculate biogenic CO_2 emissions from combustion of biomass (other than spent liquor solids) with other fuels according to the applicable methodology for stationary combustion sources in § 98.33(e).

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (b)(1) through (5) of this section:

(1) Calculate CO_2 emissions from fuel combustion using direct measurement of fuels consumed and default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1). Tiers 2 or 3 from § 98.33(a)(2) or (3) may be used to calculate CO_2 emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate CH_4 and N_2O emissions from fuel combustion using direct measurement of fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c).

(3) Calculate biogenic CO_2 emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to equation AA–2 to this section:

$$\text{Biogenic } CO_2 = \frac{44}{12} * \text{Solids} * CC * (0.90718) \qquad \text{(Eq. AA–2)}$$

Where:

Biogenic CO_2 = Annual CO_2 mass emissions for spent liquor solids combustion (metric tons per year).
Solids = Mass of the spent liquor solids combusted (short tons per year) determined according to § 98.274(b).
CC = Annual carbon content of the spent liquor solids, determined according to § 98.274(b) (percent by weight, expressed as a decimal fraction, *e.g.* , 95% = 0.95).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.90718 = Conversion from short tons to metric tons.

(4) Calculate biogenic CO_2 emissions from combustion of biomass (other than spent liquor solids) with other fuels according to the applicable methodology for stationary combustion sources in § 98.33(e).

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (c)(1) through (4) of this section:

(1) Calculate CO_2 emissions from fuel combustion using direct measurement of 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). Tiers 2 or 3 from § 98.33(a)(2) or (3) may be used to calculate CO_2 emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate CH_4 and N_2O emissions from fuel combustion using direct measurement of fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c); use the default HHV listed in table C–1 to subpart C of this part and the default CH_4 and N_2O emissions factors listed in table AA–2 to this subpart.

(3) Biogenic CO_2 emissions from conversion of $CaCO_3$ to CaO are included in the biogenic CO_2 estimates calculated for the chemical recovery furnace in paragraph (a)(3) of this section.

(4) Calculate biogenic CO_2 emissions from combustion of biomass with other fuels according to the applicable methodology for stationary combustion sources in § 98.33(e).

(d) For makeup chemical use, you must calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and the makeup chemicals, according to equation AA–3 to this section:

$$CO_2 = \left[M_{(CaCO_3)} * \frac{44}{100} + M_{(NaCO_3)} * \frac{44}{105.99}\right] * 1000 \text{ kg/metric ton} \qquad \text{(Eq. AA–3)}$$

Where:

CO_2 = CO_2 mass emissions from makeup chemicals (kilograms/yr).
M ($CaCO_3$) = Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year).
M ($NaCO_3$) = Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year).
44 = Molecular weight of CO_2.
100 = Molecular weight of $CaCO_3$.
105.99 = Molecular weight of Na_2CO_3.

■ 65. Amend § 98.276 by revising paragraph (a) to read as follows:

§ 98.276 Data reporting requirements.

* * * * *

(a) Annual emissions of CO_2, biogenic CO_2, CH_4, and N_2O (metric tons per year).

* * * * *

■ 66. Amend § 98.277 by revising paragraph (d) to read as follows:

§ 98.277 Records that must be retained.

* * * * *

(d) Annual quantity of spent liquor solids combusted in each chemical recovery furnace and chemical recovery combustion unit, and the basis for determining the annual quantity of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see § 98.7) or an online measurement system). If an online measurement system is used, you must retain records of the calculations used to determine the annual quantity of spent liquor solids combusted from the continuous measurements.

* * * * *

Subpart BB—Silicon Carbide Production

■ 67. Amend § 98.286 by revising the introductory text and adding paragraph (c) to read as follows:

§ 98.286 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraph (a) or (b) of this section, and paragraph (c) of this section, as applicable for each silicon carbide production facility.

* * * * *

(c) If methane abatement technology is used at the silicon carbide production facility, you must report the information in paragraphs (c)(1) through (3) of this section. Upon reporting this information once in an annual report, you are not required to report this information again unless the information changes during a reporting year, in which case, the reporter must include any updates in the annual report for the reporting year in which the change occurred.

(1) Type of methane abatement technology used on each silicon carbide process unit or production furnace, and date of installation for each.

(2) Methane destruction efficiency for each methane abatement technology (percent destruction). You must either use the manufacturer's specified destruction efficiency or the destruction efficiency determined via a performance test. If you report the destruction efficiency determined via a performance test, you must also report the test method that was used during the performance test.

(3) Percentage of annual operating hours that methane abatement technology was in use for all silicon carbide process units or production furnaces combined.

■ 68. Amend § 98.287 by revising the introductory text and adding paragraph (d) to read as follows:

§ 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 (d) of this section for each silicon carbide production facility.

* * * * *

(d) Records of all information reported as required under § 98.286(c).

■ 69. Revise and republish subpart DD consisting of §§ 98.300 through 98.308 to read as follows:

Subpart DD—Electrical Transmission and Distribution Equipment Use

§ 98.300 Definition of the source category.

(a) The electrical transmission and distribution equipment use source category consists of all electric transmission and distribution equipment and servicing inventory insulated with or containing fluorinated GHGs, including but not limited to sulfur hexafluoride (SF_6) and perfluorocarbons (PFCs), used within an electric power system. Electric transmission and distribution equipment and servicing inventory includes, but is not limited to:

(1) Gas-insulated substations.

(2) Circuit breakers.

(3) Switchgear, including closed-pressure and hermetically sealed-pressure switchgear and gas-insulated lines containing fluorinated GHGs, including but not limited to SF_6 and PFCs.

(4) Gas containers such as pressurized cylinders.

(5) Gas carts.

(6) Electric power transformers.

(7) Other containers of fluorinated GHG, including but not limited to SF_6 and PFCs.

(b) [Reserved]

§ 98.301 Reporting threshold.

(a) You must report GHG emissions under this subpart if you are an electric power system as defined in § 98.308 and your facility meets the requirements of § 98.2(a)(1). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in table A–3 to subpart A to this part, you must calculate emissions of each fluorinated GHG that is a component of a reportable insulating gas and then sum the emissions of each fluorinated GHG resulting from the use of electrical transmission and distribution equipment for threshold applicability purposes using equation DD–1 to this section.

$$E = \sum_j \sum_i NC_{EPS,j} * GHG_{i,w} * GWP_i * \ EF * 0.000453592 \qquad \text{(Eq. DD–1)}$$

Where:

E = Annual emissions for threshold applicability purposes (metric tons CO_2e).

$NC_{EPS,j}$ = the total nameplate capacity of equipment containing reportable insulating gas j (excluding hermetically sealed-pressure equipment) located within the facility plus the total nameplate capacity of equipment containing reportable insulting gas j (excluding hermetically sealed-pressure equipment) that is not located within the facility but is under common ownership or control (lbs).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in reportable insulating gas j in the gas insulated equipment included in the total nameplate capacity $NC_{EPS,j}$, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

EF = Emission factor for electrical transmission and distribution equipment (lbs emitted/lbs nameplate capacity). For all gases, use an emission factor or 0.1.

i = Fluorinated GHG contained in the electrical transmission and distribution equipment.

0.000453592 = Conversion factor from lbs to metric tons.

(b) A facility other than an electric power system that is subject to this part because of emissions from any other source category listed in table A–3 or A–4 to subpart A of this part is not required to report emissions under subpart DD of this part unless the total estimated emissions of fluorinated GHGs that are components of reportable insulating gases, as calculated in equation DD–2 to this section, equals or exceeds 25,000 tons CO_2e.

$$E = \sum_j \sum_i NC_{other,j} * GHG_{i,w} \ * GWP_i * \ EF * 0.000453592 \qquad \text{(Eq. DD–2)}$$

Where:

E = Annual emissions for threshold applicability purposes (metric tons CO_2e).

$NC_{other,j}$ = For a facility other than an electric power system, the total nameplate capacity of equipment containing reportable insulating gas j (excluding hermetically sealed-pressure equipment) located within the facility (lbs).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in reportable insulating gas j in the gas insulated equipment included in

the total nameplate capacity $NC_{other,j}$, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.
GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.
EF = Emission factor for electrical transmission and distribution equipment (lbs emitted/lbs nameplate capacity). For all gases, use an emission factor or 0.1.
i = Fluorinated GHG contained in the electrical transmission and distribution equipment.
0.000453592 = Conversion factor from lbs to metric tons.

§ 98.302 GHGs to report.

You must report emissions of each fluorinated GHG, including but not limited to SF_6 and PFCs, from your facility (including emissions from fugitive equipment leaks, installation, servicing, equipment decommissioning and disposal, and from storage cylinders) resulting from the transmission and distribution servicing inventory and equipment listed in § 98.300(a), except you are not required to report emissions of fluorinated GHGs that are components of insulating gases whose weighted average GWPs, as calculated in equation DD–3 to this section, are less than or equal to one. For acquisitions of equipment containing or insulated with fluorinated GHGs, you must report emissions from the equipment after the title to the equipment is transferred to the electric power transmission or distribution entity.

$$GWP_j = \sum_i GHG_{i,w} * GWP_i \qquad \text{(Eq. DD–3)}$$

Where:
GWP_j = Weighted average GWP of insulating gas j.
$GHG_{i,w}$ = The weight fraction of GHG i in insulating gas j, expressed as a decimal. fraction. If GHG i is not part of a gas mixture, use a value of 1.0.
GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.
i = GHG contained in the electrical transmission and distribution equipment.

§ 98.303 Calculating GHG emissions.

(a) *Calculating GHG emissions.* Calculate the annual emissions of each fluorinated GHG that is a component of any reportable insulating gas using the mass-balance approach in equation DD–4 to this section:

$$\text{User Emissions}_i = \Sigma_j\, GHG_{i,w} * [(\text{Decrease in Inventory of Reportable Insulating Gas j}) + (\text{Acquisitions of Reportable Insulating Gas j}) - (\text{Disbursements of Reportable Insulating Gas j}) - (\text{Net Increase in Total Nameplate Capacity of Equipment Operated Containing Reportable Insulating Gas j})] \qquad \text{(Eq. DD–4)}$$

Where:
User Emissions_i = Emissions of fluorinated GHG i from the facility (pounds).
$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in reportable insulating gas j if reportable insulating gas j is a gas mixture, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.
Decrease in Inventory of Reportable Insulating Gas j = (Pounds of reportable insulating gas j stored in containers, but not in energized equipment, at the beginning of the year) – (Pounds of reportable insulating gas j stored in containers, but not in energized equipment, at the end of the year). Reportable insulating gas inside equipment that is not energized is considered to be ‘‘stored in containers.’’
Acquisitions of Reportable Insulating gas j = (Pounds of reportable insulating gas j purchased or otherwise acquired from chemical producers, chemical distributors, or other entities in bulk) + (Pounds of reportable insulating gas j purchased or otherwise acquired from equipment manufacturers, equipment distributors, or other entities with or inside equipment, including hermetically sealed-pressure switchgear, while the equipment was not in use) + (Pounds of each SF_6 insulating gas j returned to facility after off-site recycling) + (Pounds of reportable insulating gas j acquired inside equipment, except hermetically sealed-pressure switchgear, that was transferred while the equipment was in use, *e.g.,* through acquisition of all or part of another electric power system).
Disbursements of Reportable Insulating gas j = (Pounds of reportable insulating gas j returned to suppliers) + (Pounds of reportable insulating gas j sent off site for recycling) + (Pounds of reportable insulating gas j sent off-site for destruction) + (Pounds of reportable insulating gas j that was sold or transferred to other entities in bulk) + (Pounds of reportable insulating gas j contained in equipment, including hermetically sealed-pressure switchgear, that was sold or transferred to other entities while the equipment was not in use) + (Pounds of reportable insulating gas j inside equipment, except hermetically sealed-pressure switchgear, that was transferred while the equipment was in use, *e.g.,* through sale of all or part of the electric power system to another electric power system).
Net Increase in Total Nameplate Capacity of Equipment Operated containing reportable insulating gas j = (The Nameplate Capacity of new equipment, as defined at § 98.308, containing reportable insulating gas j in pounds) – (Nameplate Capacity of retiring equipment, as defined at § 98.308, containing reportable insulating gas j in pounds). (Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage).

(b) *Nameplate capacity adjustments.* Users of closed-pressure electrical equipment with a voltage capacity greater than 38 kV may measure and adjust the nameplate capacity value specified by the equipment manufacturer on the nameplate attached to that equipment, or within the equipment manufacturer's official product specifications, by following the requirements in paragraphs (b)(1) through (10) of this section. Users of other electrical equipment are not permitted to adjust the nameplate capacity value of the other equipment.

(1) If you elect to measure the nameplate capacity value(s) of one or more pieces of electrical equipment with a voltage capacity greater than 38 kV, you must measure the nameplate capacity values of all the electrical

equipment in your facility that has a voltage capacity greater than 38 kV and that is installed or retired in that reporting year and in subsequent reporting years.

(2) You must adopt the measured nameplate capacity value for any piece of equipment for which the absolute value of the difference between the measured nameplate capacity value and the nameplate capacity value most recently specified by the manufacturer equals or exceeds two percent of the nameplate capacity value most recently specified by the manufacturer.

(3) You may adopt the measured nameplate capacity value for equipment for which the absolute value of the difference between the measured nameplate capacity value and the nameplate capacity value most recently specified by the manufacturer is less than two percent of the nameplate capacity value most recently specified by the manufacturer, but if you elect to adopt the measured nameplate capacity for that equipment, then you must adopt the measured nameplate capacity value for all of the equipment for which the difference between the measured nameplate capacity value and the nameplate capacity value most recently specified by the manufacturer is less than two percent of the nameplate capacity value most recently specified by the manufacturer. This applies in the reporting year in which you first adopt the measured nameplate capacity for the equipment and in subsequent reporting years.

(4) Users of electrical equipment measuring the nameplate capacity of any new electrical equipment must:

(i) Record the amount of insulating gas in the equipment at the time the equipment was acquired (pounds), either per information provided by the manufacturer, or by transferring insulating gas from the equipment to a gas container and measuring the amount of insulating gas transferred. The equipment user is responsible for ensuring the gas is accounted for consistent with the methodologies specified in paragraphs (b)(4)(ii) through (iii) and (b)(5) of this section. If no insulating gas was in the device when it was acquired, record this value as zero.

(ii) If insulating gas is added to the equipment subsequent to the acquisition of the equipment to energize it the first time, transfer the insulating gas to the equipment to reach the temperature-compensated design operating pressure per manufacturer specifications. Follow the manufacturer-specified procedure to ensure that the measured temperature accurately reflects the temperature of the insulating gas, *e.g.,* by measuring the insulating gas pressure and vessel temperature after allowing appropriate time for the temperature of the transferred gas to equilibrate with the vessel temperature. Measure and calculate the total amount of reportable insulating gas added to the device using one of the methods specified in paragraphs (b)(4)(ii)(A) and (B) of this section.

(A) To determine the amount of reportable insulating gas transferred to the electrical equipment, weigh the gas container being used to fill the device prior to, and after, the addition of the reportable insulating gas to the electrical equipment, and subtract the second value (after-transfer gas container weight) from the first value (prior-to-transfer gas container weight). Account for any gas contained in hoses before and after the transfer.

(B) Connect a mass flow meter between the electrical equipment and a gas cart. Transfer gas to the equipment to reach the temperature-compensated design operating pressure per manufacturer specifications. During gas transfer, you must keep the mass flow rate within the range specified by the mass flow meter manufacturer to assure an accurate and precise mass flow meter reading. Close the connection to the GIE from the mass flow meter hose and ensure that the gas trapped in the filling hose returns through the mass flow meter. Calculate the amount of gas transferred from the mass reading on the mass flow meter.

(iii) Sum the results of paragraphs (b)(4)(i) and (ii) to obtain the measured nameplate capacity for the new equipment.

(5) Electrical equipment users measuring the nameplate capacity of any retiring electrical equipment must:

(i) Measure and record the initial system pressure and vessel temperature prior to removing any insulating gas.

(ii) Compare the initial system pressure and temperature to the equipment manufacturer's temperature/pressure curve for that equipment and insulating gas.

(iii) If the temperature-compensated initial system pressure of the electrical equipment does not match the temperature-compensated design operating pressure specified by the equipment manufacturer, you may either:

(A) Add or remove insulating gas to/from the electrical equipment until the manufacturer-specified value is reached, or

(B) If the temperature-compensated initial system pressure of the electrical equipment is no higher than the temperature-compensated design operating pressure specified by the manufacturer and no lower than five pounds per square inch (5 psi) less than the temperature-compensated design operating pressure specified by the manufacturer, use equation DD–5 to this section to calculate the nameplate capacity based on the mass recorded under paragraph (b)(5)(vi) of this section.

(iv) Weigh the gas container being used to receive the gas and record this value.

(v) Recover insulating gas from the electrical equipment until five minutes after the pressure in the electrical equipment reaches a pressure of at most five pounds per square inch absolute (5 psia).

(vi) Record the amount of insulating gas recovered (pounds) by weighing the gas container that received the gas and subtracting the weight recorded pursuant to paragraph (b)(5)(iv)(B) of this section from this value. Account for any gas contained in hoses before and after the transfer. The amount of gas recovered shall be the measured nameplate capacity for the electrical equipment unless the final temperature-compensated pressure of the electrical equipment exceeds 0.068 psia (3.5 Torr) or the electrical equipment user is calculating the nameplate capacity pursuant to paragraph (b)(5)(iii)(B) of this section, in which cases the measured nameplate capacity shall be the result of equation DD–5 to this section.

(vii) If you are calculating the nameplate capacity pursuant to paragraph (b)(5)(iii)(B) of this section, use equation DD–5 to this section to do so.

$$NC_C = \frac{P_{NC}}{(P_i - P_f)} \times M_R \qquad \text{(Eq. DD–5)}$$

Where:

NC_C = Nameplate capacity of the equipment measured and calculated by the equipment user (pounds).

P_i = Initial temperature-compensated pressure of the equipment, based on the temperature-pressure curve for the insulating gas (psia).

P_f = Final temperature-compensated pressure of the equipment, based on the temperature-pressure curve for the insulating gas (psia). This may be equated to zero if the final temperature-compensated pressure of the equipment is equal to or lower than 0.068 psia (3.5 Torr).

P_{NC} = Temperature-compensated pressure of the equipment at the manufacturer-specified filling density of the equipment (*i.e.,* at the full and proper charge, psia).

M_R = Mass of insulating gas recovered from the equipment, measured in paragraph (b)(5)(vi) of this section (pounds).

(viii) Record the final system pressure and vessel temperature.

(6) Instead of measuring the nameplate capacity of electrical equipment when it is retired, users may measure the nameplate capacity of electrical equipment during maintenance activities that require opening the gas compartment, but they must follow the procedures set forth in paragraph (b)(5) of this section.

(7) If the electrical equipment will remain energized, and the electrical equipment user is adopting the user-measured nameplate capacity, the electrical equipment user must affix a revised nameplate capacity label, showing the revised nameplate value and the year the nameplate capacity adjustment process was performed, to the device by the end of the calendar year in which the process was completed. The manufacturer's previous nameplate capacity label must remain visible after the revised nameplate capacity label is affixed to the device.

(8) For each piece of electrical equipment whose nameplate capacity was adjusted during the reporting year, the revised nameplate capacity value must be used in all provisions wherein the nameplate capacity is required to be recorded, reported, or used in a calculation in this subpart unless otherwise specified herein.

(9) The nameplate capacity of a piece of electrical equipment may only be adjusted more than once if the physical capacity of the device has changed (*e.g.,* replacement of bushings) after the initial adjustment was performed, in which case the equipment user must adjust the nameplate capacity pursuant to the provisions of this paragraph (b).

(10) Measuring devices used to measure the nameplate capacity of electrical equipment under this paragraph (b) must meet the following accuracy and precision requirements:

(i) Flow meters must be certified by the manufacturer to be accurate and precise to within one percent of the largest value that the flow meter can, according to the manufacturer's specifications, accurately record.

(ii) Pressure gauges must be certified by the manufacturer to be accurate and precise to within 0.5% of the largest value that the gauge can, according to the manufacturer's specifications, accurately record.

(iii) Temperature gauges must be certified by the manufacturer to be accurate and precise to within +/−1.0 °F.

(iv) Scales must be certified by the manufacturer to be accurate and precise to within one percent of the true weight.

§ 98.304 Monitoring and QA/QC requirements.

(a) [Reserved]

(b) You must adhere to the following QA/QC methods for reviewing the completeness and accuracy of reporting:

(1) Review inputs to equation DD–4 to § 98.303 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 fluorinated GHG 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 fluorinated GHG purchased from bulk gas distributors, fluorinated GHG purchased from Original Equipment Manufacturers (OEM) and fluorinated GHG returned to the facility from off-site recycling are also accounted for among the total additions.

(c) 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 2 pounds of 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 ±2 pounds, of residual gas amounts in the cylinders returned to the gas supplier.

(2) Ensure that cylinders weighed for the beginning and end of year inventory measurements are weighed on a scale that is certified to be accurate and precise to within 2 pounds of true weight and is periodically recalibrated per the manufacturer's specifications. All scales used to measure quantities that are to be reported under § 98.306 must be calibrated using calibration procedures specified by the scale manufacturer. Calibration must be performed prior to the first reporting year. After the initial calibration, recalibration must be performed at the minimum frequency specified by the manufacturer.

(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).

(d) GHG Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011.

§ 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 fluorinated GHGs, 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 (pounds) containing each insulating gas:

(1) Existing at the beginning of the year (excluding hermetically sealed-pressure switchgear).

(2) New hermetically sealed-pressure switchgear during the year.

(3) New equipment other than hermetically sealed-pressure switchgear during the year.

(4) Retired hermetically sealed-pressure switchgear during the year.

(5) Retired equipment other than hermetically sealed-pressure switchgear during the year.

(b) Transmission miles (length of lines carrying voltages above 35 kilovolts).

(c) Distribution miles (length of lines carrying voltages at or below 35 kilovolts).

(d) Pounds of each reportable insulating gas stored in containers, but not in energized equipment, at the beginning of the year.

(e) Pounds of each reportable insulating gas stored in containers, but not in energized equipment, at the end of the year.

(f) Pounds of each reportable insulating gas purchased or otherwise acquired in bulk from chemical producers, chemical distributors, or other entities.

(g) Pounds of each reportable insulating gas purchased or otherwise acquired from equipment manufacturers, equipment distributors, or other entities with or inside equipment, including hermetically sealed-pressure switchgear, while the equipment was not in use.

(h) Pounds of each reportable insulating gas returned to facility after off-site recycling.

(i) Pounds of each reportable insulating gas acquired inside equipment, except hermetically sealed-pressure switchgear, that was transferred while the equipment was in use, *e.g.,* through acquisition of all or part of another electric power system.

(j) Pounds of each reportable insulating gas returned to suppliers.

(k) Pounds of each reportable insulating gas that was sold or transferred to other entities in bulk.

(l) Pounds of each reportable insulating gas sent off-site for recycling.

(m) Pounds of each reportable insulating gas sent off-site for destruction.

(n) Pounds of each reportable insulating gas contained in equipment, including hermetically sealed-pressure switchgear, that was sold or transferred to other entities while the equipment was not in use.

(o) Pounds of each reportable insulating gas disbursed inside equipment, except hermetically sealed-pressure switchgear, that was transferred while the equipment was in use, *e.g.,* through sale of all or part of the electric power system to another electric power system.

(p) State(s) or territory in which the facility lies.

(q) The number of reportable-insulating-gas-containing pieces of equipment in each of the following equipment categories:

(1) New hermetically sealed-pressure switchgear during the year.

(2) New equipment other than hermetically sealed-pressure switchgear during the year.

(3) Retired hermetically sealed-pressure switchgear during the year.

(4) Retired equipment other than hermetically sealed-pressure switchgear during the year.

(r) The total of the nameplate capacity values most recently assigned by the electrical equipment manufacturer(s) to each of the following groups of equipment:

(1) All new equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(2) All retiring equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(s) The total of the nameplate capacity values measured by the electrical equipment user for each of the following groups of equipment:

(1) All new equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(2) All retiring equipment whose nameplate capacity values were measured by the user under this subpart and for which the user adopted the user-measured nameplate capacity value during the year.

(t) For each reportable insulating gas reported in paragraphs (a), (d) through (o), and (q) of this section, an ID number or other appropriate descriptor that is unique to that reportable insulating gas.

(u) For each ID number or descriptor reported in paragraph (t) of this section for each unique insulating gas, the name (as required in § 98.3(c)(4)(iii)(G)(1)) and weight percent of each fluorinated gas in the insulating gas.

§ 98.307 Records that must be retained.

(a) In addition to the information required by § 98.3(g), you must retain records of the information reported and listed in § 98.306.

(b) For each piece of electrical equipment whose nameplate capacity is measured by the equipment user, retain records of the following:

(1) Equipment manufacturer name.

(2) Year equipment was manufactured. If the date year the equipment was manufactured cannot be determined, report a best estimate of the year of manufacture and record how the estimated year was determined.

(3) Manufacturer serial number. For any piece of equipment whose serial number is unknown (*e.g.,* the serial number does not exist or is not visible), another unique identifier must be recorded as the manufacturer serial number. The electrical equipment user must retain documentation that allows for each electrical equipment to be readily identifiable.

(4) Equipment type (*i.e.,* closed-pressure vs. hermetically sealed-pressure).

(5) Equipment voltage capacity (in kilovolts).

(6) The name and GWP of each insulating gas used.

(7) Nameplate capacity value (pounds), as specified by the equipment manufacturer. The value must reflect the latest value specified by the manufacturer during the reporting year.

(8) Nameplate capacity value (pounds) measured by the equipment user.

(9) The date the nameplate capacity measurement process was completed.

(10) The measurements and calculations used to calculate the value in paragraph (b)(8) of this section.

(11) The temperature-pressure curve and/or other information used to derive the initial and final temperature-adjusted pressures of the equipment.

(12) Whether or not the nameplate capacity value in paragraph (b)(8) of this section has been adopted for the piece of electrical equipment.

§ 98.308 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Facility, with respect to an electric power system, means the electric power system as set out in this definition. An electric power system is comprised of all electric transmission and distribution equipment insulated with or containing fluorinated GHGs that is linked through electric power transmission or distribution lines and functions as an integrated unit, that is owned, serviced, or maintained by a single electric power transmission or distribution entity (or multiple entities with a common owner), and that is located between:

(1) The point(s) at which electric energy is obtained from an electricity generating unit or a different electric power transmission or distribution entity that does not have a common owner; and

(2) The point(s) at which any customer or another electric power transmission or distribution entity that does not have a common owner receives the electric energy. The facility also includes servicing inventory for such equipment that contains fluorinated GHGs.

Electric power transmission or distribution entity means any entity that transmits, distributes, or supplies electricity to a consumer or other user, including any company, electric cooperative, public electric supply corporation, a similar Federal department (including the Bureau of Reclamation or the Corps of Engineers), a municipally owned electric department offering service to the public, an electric public utility district, or a jointly owned electric supply project.

Energized, for the purposes of this subpart, means connected through busbars or cables to an electrical power system or fully-charged, ready for service, and being prepared for connection to the electrical power system. Energized equipment does not include spare gas insulated equipment (including hermetically-sealed pressure switchgear) in storage that has been acquired by the facility, and is intended for use by the facility, but that is not being used or prepared for connection to the electrical power system.

Insulating gas, for the purposes of this subpart, means any fluorinated GHG or fluorinated GHG mixture, including but not limited to SF_6 and PFCs, that is used as an insulating and/or arc-quenching gas in electrical equipment.

New equipment, for the purposes of this subpart, means either any gas insulated equipment, including hermetically-sealed pressure switchgear, that is not energized at the beginning of the reporting year but is energized at the end of the reporting year, or any gas insulated equipment other than hermetically-sealed pressure switchgear that has been transferred while in use, meaning it has been added to the facility's inventory without being taken out of active service (*e.g.,* when the equipment is sold to or acquired by the facility while remaining in place and continuing operation).

Operator, for the purposes of this subpart, means any person who operates or supervises a facility, excluding a person whose sole responsibility is to ensure reliability, balance load or otherwise address electricity flow.

Reportable insulating gas, for purposes of this subpart, means an insulating gas whose weighted average GWP, as calculated in equation DD–3 to § 98.302, is greater than one. A fluorinated GHG that makes up either part or all of a reportable insulating gas is considered to be a component of the reportable insulating gas.

Retired equipment, for the purposes of this subpart, means either any gas insulated equipment including hermetically-sealed pressure switchgear, that is energized at the beginning of the reporting year but is not energized at the end of the reporting year, or any gas insulated equipment other than hermetically-sealed pressure switchgear that has been transferred while in use, meaning it has been removed from the facility's inventory without being taken out of active service (*e.g.,* when the equipment is acquired by a new facility while remaining in place and continuing operation).

Subpart FF—Underground Coal Mines

■ 70. Amend § 98.323 by revising parameter ''MCFi'' of equation FF–3 in paragraph (b) introductory text to read as follows:

§ 98.323 Calculating GHG emissions.

* * * * *

(b) * * *

MCF_i = Moisture correction factor for the measurement period, volumetric basis.

= 1 when V_i and C_i are measured on a dry basis or if both are measured on a wet basis.

= $1 - (fH2O)_i$ when V_i is measured on a wet basis and C_i is measured on a dry basis.

= $1/[1 - (fH2O)_i]$ when V_i is measured on a dry basis and C_i is measured on a wet basis.

* * * * *

■ 71. Amend § 98.326 by revising paragraph (t) to read as follows:

§ 98.326 Data reporting requirements.

* * * * *

(t) Mine Safety and Health Administration (MSHA) identification number for this coal mine.

Subpart GG—Zinc Production

■ 72. Amend § 98.333 by revising paragraph (b)(1) introductory text to read as follows:

§ 98.333 Calculating GHG emissions.

* * * * *

(b) * * *

(1) For each Waelz kiln or electrothermic furnace at your facility used for zinc production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into each Waelz kiln and electrothermic furnace at your facility for each year and calculate annual CO_2 process emissions from each affected unit at your facility using equation GG–1 to this section. For electrothermic furnaces, carbon containing input materials include carbon electrodes and carbonaceous reducing agents. For Waelz kilns, carbon containing input materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using equation R–1 to § 98.183.

* * * * *

■ 73. Amend § 98.336 by adding paragraphs (a)(6) and (b)(6) to read as follows:

§ 98.336 Data reporting requirements.

* * * * *

(a) * * *

(6) Total amount of electric arc furnace dust annually consumed by all Waelz kilns at the facility (tons).

(b) * * *

(6) Total amount of electric arc furnace dust annually consumed by all Waelz kilns at the facility (tons).

* * * * *

Subpart HH—Municipal Solid Waste Landfills

■ 74. Amend § 98.343 by revising paragraphs (a)(2) and (c)(3) to read as follows:

§ 98.343 Calculating GHG emissions.

(a) * * *

(2) For years when material-specific waste quantity data are available, apply equation HH–1 to this section for each waste quantity type and sum the CH_4 generation rates for all waste types to calculate the total modeled CH_4 generation rate for the landfill. Use the appropriate parameter values for k, DOC, MCF, DOC_F, and F shown in table HH–1 to this subpart. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. You may use the uncharacterized MSW 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 DOC in table HH–1 to this subpart for the total quantity of waste disposed in those years.

* * * * *

(c) * * *

(3) For landfills with landfill gas collection systems, calculate CH_4 emissions using the methodologies specified in paragraphs (c)(3)(i) and (ii) of this section.

(i) Calculate CH_4 emissions from the modeled CH_4 generation and measured CH_4 recovery using equation HH–6 to this section.

$$\text{Emissions} = \left[\left(G_{CH4} - \sum_{n=1}^{N} R_n\right) x \left(1 - OX\right) + \sum_{n=1}^{N}\left\{R_n \times \left(1 - \left(DE_n \times F_{Dest,n}\right)\right)\right\}\right] \quad \text{(Eq. HH–6)}$$

Where:

Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).

G_{CH4} = Modeled methane generation rate in reporting year from equation HH–1 to this section or the quantity of recovered CH_4 from equation HH–4 to this section, whichever is greater (metric tons CH_4).

N = Number of landfill gas measurement locations (associated with a destruction device or gas sent off-site). If a single monitoring location is used to monitor volumetric flow and CH_4 concentration of the recovered gas sent to one or multiple destruction devices, then N = 1.

R_n = Quantity of recovered CH_4 from equation HH–4 to this section for the nth measurement location (metric tons CH_4).

OX = Oxidation fraction. Use the appropriate oxidation fraction default value from table HH–4 to this subpart.

DE_n = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99) for the nth measurement location. If the gas is transported off-site for destruction, use DE = 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate DE_n as the arithmetic average of the DE values determined for each destruction device associated with that measurement location.

$f_{Dest,n}$ = Fraction of hours the destruction device associated with the nth measurement location was operating during active gas flow calculated as the annual operating hours for the destruction device divided by the annual hours flow was sent to the destruction device. The annual operating hours for the destruction device should include only those periods when flow was sent to the destruction device and the destruction device was operating at its intended temperature or other parameter indicative of effective operation. For flares, times when there is no flame present must be excluded from the annual operating hours for the destruction device. If the gas is transported off-site for destruction, use $f_{Dest,n}$ = 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate $f_{Dest,n}$ as the arithmetic average of the f_{Dest} values determined for each destruction device associated with that measurement location.

(ii) Calculate CH_4 generation and CH_4 emissions using measured CH_4 recovery and estimated gas collection efficiency and equations HH–7 and HH–8 to this section.

$$MG = \left[\frac{1}{CE}\sum_{c=1}^{C}\left[\frac{\sum_{x=1}^{X} R_{x,c}}{f_{Rec,c}}\right] \times \left(1 \text{ - } OX\right)\right] \quad \text{(Eq. HH–7)}$$

$$\text{Emissions} = \left[\left(\frac{1}{CE}\sum_{c=1}^{C}\left[\frac{\sum_{x=1}^{X} R_{x,c}}{f_{Rec,c}}\right] - \sum_{n=1}^{N} R_n\right) \times \left(1 - OX\right) + \sum_{n=1}^{N}\left\{R_n \times \left(1 - \left(DE_n \times f_{Dest,n}\right)\right)\right\}\right] \quad \text{(Eq. HH–8)}$$

Where:

MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH_4).

Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).

C = Number of landfill gas collection systems operated at the landfill.

X = Number of landfill gas measurement locations associated with landfill gas collection system "c".

N = Number of landfill gas measurement locations (associated with a destruction device or gas sent off-site). If a single monitoring location is used to monitor volumetric flow and CH_4 concentration of the recovered gas sent to one or multiple destruction devices, then N = 1. Note that $N = \Sigma_{(c=1)}{}^{C}[\Sigma_{(x=1)}{}^{X}[1]]$.

$R_{x,c}$ = Quantity of recovered CH_4 from equation HH–4 to this section for the xth measurement location for landfill gas collection system "c" (metric tons CH_4).

R_n = Quantity of recovered CH_4 from equation HH–4 to this section for the nth measurement location (metric tons CH_4).

CE = Collection efficiency estimated at landfill, taking into account system coverage, operation, measurement practices, and cover system materials from table HH–3 to this subpart. If area by soil cover type information is not available, use applicable default value for CE4 in table HH–3 to this subpart for all areas under active influence of the collection system.

$f_{Rec,c}$ = Fraction of hours the landfill gas collection system "c" was operating normally (annual operating hours/8760 hours per year or annual operating hours/8784 hours per year for a leap year). Do not include periods of shutdown or poor operation, such as times when pressure, temperature, or other parameters indicative of operation are outside of normal variances, in the annual operating hours.

OX = Oxidation fraction. Use appropriate oxidation fraction default value from table HH–4 to this subpart.

DE_n = Destruction efficiency, (lesser of manufacturer's specified destruction efficiency and 0.99) for the nth measurement location. If the gas is transported off-site for destruction, use DE = 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate DE_n as the arithmetic average of the DE values determined for each destruction device associated with that measurement location.

$f_{Dest,n}$ = Fraction of hours the destruction device associated with the nth measurement location was operating during active gas flow calculated as the annual operating hours for the destruction device divided by the annual hours flow was sent to the destruction device. The annual operating hours for the destruction device should include only those periods when flow was sent to the destruction device and the destruction device was operating at its intended temperature or other parameter indicative of effective operation. For flares, times when there is no flame present must be excluded from the annual operating hours for the destruction device. If the gas is transported off-site for destruction, use $f_{Dest,n}$ = 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate $f_{Dest,n}$ as the arithmetic average of the f_{Dest} values determined for each destruction device associated with that measurement location.

■ 75. Amend § 98.346 by:

■ a. Redesignating paragraphs (h) and (i) as paragraphs (i) and (j), respectively.

■ b. Adding new paragraph (h); and

■ c. Revising newly redesignated paragraphs (j)(5) through (7).

The addition and revisions read as follows:

§ 98.346 Data reporting requirements.

* * * * *

(h) An indication of the applicability of part 60 or part 62 of this chapter requirements to the landfill (part 60, subparts WWW and XXX of this chapter, approved state plan implementing part 60, subparts Cc or Cf of this chapter, Federal plan as implemented at part 62, subparts GGG or OOO of this chapter, or not subject to part 60 or part 62 of this chapter municipal solid waste landfill rules), and if the landfill is subject to a part 60 or part 62 of this chapter municipal solid waste landfill rule, an indication of whether the landfill gas collection system is required under part 60 or part 62 of this chapter.

* * * * *

(j) * * *

(5) The number of gas collection systems at the landfill facility.

(6) For each gas collection system at the facility report:

(i) A unique name or ID number for the gas collection system.

(ii) A description of the gas collection system (manufacturer, capacity, and number of wells).

(iii) The annual hours the gas collection system was operating normally. Do not include periods of shut down or poor operation, such as times when pressure, temperature, or other parameters indicative of operation are outside of normal variances, in the annual operating hours.

(iv) The number of measurement locations associated with the gas collection system.

(v) For each measurement location associated with the gas collection system, report:

(A) A unique name or ID number for the measurement location.

(B) Annual quantity of recovered CH_4 (metric tons CH_4) calculated using equation HH–4 to § 98.343.

(C) An indication of whether destruction occurs at the landfill facility, off-site, or both for the measurement location.

(D) If destruction occurs at the landfill facility for the measurement location (in full or in part), also report the number of destruction devices associated with the measurement location that are located at the landfill facility and the information in paragraphs (j)(6)(v)(D)(*1*) through (6) of this section for each destruction device located at the landfill facility.

(*1*) A unique name or ID number for the destruction device.

(*2*) The type of destruction device (flare, a landfill gas to energy project (*i.e.,* engine or turbine), off-site, or other (specify)).

(*3*) The destruction efficiency (decimal).

(*4*) The total annual hours where active gas flow was sent to the destruction device.

(*5*) The annual operating hours where active gas flow was sent to the destruction device and the destruction device was operating at its intended temperature or other parameter indicative of effective operation. For flares, times when there is no flame present must be excluded from the annual operating hours for the destruction device.

(*6*) The estimated fraction of the recovered CH4 reported for the measurement location directed to the destruction device based on best available data or engineering judgement (decimal, must total to 1 for each measurement location).

(*7*) The following information about the landfill.

(i) The surface area (square meters) and estimated waste depth (meters) for each area specified in table HH–3 to this subpart.

(ii) The estimated gas collection system efficiency for the landfill.

(iii) An indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in § 98.6) are present at the landfill.

* * * * *

■ 76. Revise table HH–1 to subpart HH to read as follows:

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS

Factor	Default value	Units
DOC and k values—Bulk waste option:		
DOC (bulk waste) for disposal years prior to 2010	0.20	Weight fraction, wet basis.
DOC (bulk waste) for disposal years 2010 and later	0.17	Weight fraction, wet basis.
k (precipitation plus recirculated leachate [a] <20 inches/year) for disposal years prior to 2010.	0.02	yr^{-1}.
k (precipitation plus recirculated leachate [a] <20 inches/year) for disposal years 2010 and later.	0.033	yr^{-1}.
k (precipitation plus recirculated leachate [a] 20–40 inches/year) for disposal years prior to 2010.	0.038	yr^{-1}.
k (precipitation plus recirculated leachate [a] 20–40 inches/year) for disposal years 2010 and later.	0.067	yr^{-1}.
k (precipitation plus recirculated leachate [a] >40 inches/year) for disposal years prior to 2010.	0.057	yr^{-1}.
k (precipitation plus recirculated leachate [a] >40 inches/year) for disposal years 2010 and later.	0.098	yr^{-1}.
DOC and k values—Modified bulk MSW option:		
DOC (bulk MSW, excluding inerts and C&D waste) for disposal years prior to 2010.	0.31	Weight fraction, wet basis.
DOC (bulk MSW, excluding inerts and C&D waste) for disposal years 2010 and later.	0.27	Weight fraction, wet basis.
DOC (inerts, *e.g.,* glass, plastics, metal, concrete)	0.00	Weight fraction, wet basis.
DOC (C&D waste)	0.08	Weight fraction, wet basis.
k (bulk MSW, excluding inerts and C&D waste) for disposal years prior to 2010.	0.02 to 0.057 [b]	yr^{-1}.
k (bulk MSW, excluding inerts and C&D waste) for disposal years 2010 and later.	0.033 to 0.098 [b]	yr^{-1}.

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS—Continued

Factor	Default value	Units
k (inerts, *e.g.,* glass, plastics, metal, concrete)	0.00	yr^{-1}.
k (C&D waste)	0.02 to 0.04 [b]	yr^{-1}.
DOC and k values—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 (inerts, *e.g.,* glass, plastics, metal, cement)	0.00	Weight fraction, wet basis.
DOC (Uncharacterized MSW	0.32	Weight fraction, wet basis.
k (food waste)	0.06 to 0.185 [c]	yr^{-1}.
k (garden)	0.05 to 0.10 [c]	yr^{-1}.
k (paper)	0.04 to 0.06 [c]	yr^{-1}.
k (wood and straw)	0.02 to 0.03 [c]	yr^{-1}.
k (textiles)	0.04 to 0.06 [c]	yr^{-1}.
k (diapers)	0.05 to 0.10 [c]	yr^{-1}.
k (sewage sludge)	0.06 to 0.185 [c]	yr^{-1}.
k (inerts, *e.g.,* glass, plastics, metal, concrete)	0.00	yr^{-1}.
k (uncharacterized MSW)	0.033 to 0.098 [b]	yr^{-1}.
Other parameters—All MSW landfills:		
MCF	1.	
DOC_F	0.5.	
F	0.5.	
OX	See table HH–4 to this subpart.	
DE	0.99.	

[a] Recirculated leachate (in inches/year) is the total volume of leachate recirculated from company records or engineering estimates divided by the area of the portion of the landfill containing waste with appropriate unit conversions. Alternatively, landfills that use leachate recirculation can elect to use the k value of 0.098 rather than calculating the recirculated leachate rate.

[b] Use the lesser value when precipitation plus recirculated leachate is less than 20 inches/year. Use the greater value when precipitation plus recirculated leachate is greater than 40 inches/year. Use the average of the range of values when precipitation plus recirculated leachate is 20 to 40 inches/year (inclusive). Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than calculating the recirculated leachate rate.

[c] Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate plus recirculated leachate. Use the greater value when the potential evapotranspiration rate does not exceed the mean annual precipitation rate plus recirculated leachate. Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than assessing the potential evapotranspiration rate or recirculated leachate rate.

■ 77. Revise table HH–3 to subpart HH to read as follows:

TABLE HH–3 TO SUBPART HH OF PART 98—LANDFILL GAS COLLECTION EFFICIENCIES

Description	Term ID	Landfill gas collection efficiency
A1: Area with no waste in-place	Not applicable; do not use this area in the calculation.	
A2: Area without active gas collection, regardless of cover type	CE2	0%.
A3: Area with daily soil cover and active gas collection	CE3	50%.
A4: Area with an intermediate soil cover, or a final soil cover not meeting the criteria for A5 below, and active gas collection.	CE4	65%.
A5: Area with a final soil cover of 3 feet or thicker of clay or final cover (as approved by the relevant agency) and/or geomembrane cover system and active gas collection.	CE5	85%.
Area weighted average collection efficiency for landfills	CEave1 = (A2*CE2 + A3*CE3 + A4*CE4 + A5*CE5)/(A2 + A3 + A4 + A5).	

■ 78. Revise footnote "b" to table HH—4 to subpart HH to read as follows:

TABLE HH–4 TO SUBPART HH OF PART 98—LANDFILL METHANE OXIDATION FRACTIONS

Under these conditions:	Use this landfill methane oxidation fraction:
* * * * * *	*

* * * * * * *

[b] Methane flux rate (in grams per square meter per day; g/m^2/d) is the mass flow rate of methane per unit area at the bottom of the surface soil prior to any oxidation and is calculated as follows:

For equation HH–5 to § 98.343, or for equation TT–6 to § 98.463,

$MF = K \times G_{CH4}/SArea$

For equation HH–6 to § 98.343,

$$MF = K \times \left(G_{CH4} - \sum_{n=1}^{N} R_n\right) \Big/ SArea$$

For equation HH–7 to § 98.343,

$$MF = K \times \left(\frac{1}{CE} \sum_{c=1}^{C} \left[\frac{\sum_{x=1}^{X} R_{x,c}}{f_{Rec,c}}\right]\right) \Big/ Sarea$$

For equation HH–8 to § 98.343,

$$MF = K \times \left(\frac{1}{CE} \sum_{c=1}^{C} \left[\frac{\sum_{x=1}^{X} R_{x,c}}{f_{Rec,c}}\right] - \sum_{n=1}^{N} R_n\right) \Big/ Sarea$$

Where:

MF = Methane flux rate from the landfill in the reporting year (grams per square meter per day, g/m^2/d).

K = unit conversion factor = $10^6/365$ (g/metric ton per days/year) or $10^6/366$ for a leap year.

SArea = The surface area of the landfill containing waste at the beginning of the reporting year (square meters, m^2).

G_{CH4} = Modeled methane generation rate in reporting year from equation HH–1 to § 98.343 or equation TT–1 to § 98.463, as applicable, except for application with equation HH–6 to § 98.343 (metric tons CH_4). For application with equation HH–6 to § 98.343, the greater of the modeled methane generation rate in reporting year from equation HH–1 to § 98.343 or equation TT–1 to § 98.463, as applicable, and the quantity of recovered CH_4 from equation HH–4 to § 98.343 (metric tons CH_4).

CE = Collection efficiency estimated at landfill, taking into account system coverage, operation, measurement practices, and cover system materials from table HH–3 to this subpart. If area by soil cover type information is not available, use applicable default value for CE4 in table HH–3 to this subpart for all areas under active influence of the collection system.

C = Number of landfill gas collection systems operated at the landfill.

X = Number of landfill gas measurement locations associated with landfill gas collection system ''c''.

N = Number of landfill gas measurement locations (associated with a destruction device or gas sent off-site). If a single monitoring location is used to monitor volumetric flow and CH_4 concentration of the recovered gas sent to one or multiple destruction devices, then N = 1. Note that $N = \Sigma_{c=1}{}^{C}[\Sigma_{x=1}{}^{X}[1]]$.

$R_{x,c}$ = Quantity of recovered CH_4 from equation HH–4 to § 98.343 for the xth measurement location for landfill gas collection system ''c'' (metric tons CH_4).

R_n = Quantity of recovered CH_4 from equation HH–4 to § 98.343 for the nth measurement location (metric tons CH_4).

$f_{Rec,c}$ = Fraction of hours the landfill gas collection system ''c'' was operating normally (annual operating hours/8,760 hours per year or annual operating hours/8,784 hours per year for a leap year). Do not include periods of shutdown or poor operation, such as times when pressure, temperature, or other parameters indicative of operation are outside of normal variances, in the annual operating hours.

Subpart OO—Suppliers of Industrial Greenhouse Gases

■ 79. Amend § 98.416 by revising paragraphs (c) introductory text, (c)(6) and (7), (d) introductory text, and (d)(4), and adding paragraph (k) to read as follows:

§ 98.416 Data reporting requirements.

* * * * *

(c) Each bulk importer of fluorinated GHGs, fluorinated heat transfer fluids (HTFs), or nitrous oxide shall submit an annual report that summarizes its imports at the corporate level, except importers may exclude shipments including less than twenty-five kilograms of fluorinated GHGs, fluorinated HTFs, or nitrous oxide; transshipments if the importer also excludes transshipments from reporting of exports under paragraph (d) of this section; and heels that meet the conditions set forth at § 98.417(e) if the importer also excludes heels from any reporting of exports under paragraph (d) of this section. The report shall contain the following information for each import:

* * * * *

(6) Harmonized tariff system (HTS) code of the fluorinated GHGs, fluorinated HTFs, or nitrous oxide shipped.

(7) Customs entry number and importer number for each shipment.

* * * * *

(d) Each bulk exporter of fluorinated GHGs, fluorinated HTFs, or nitrous oxide shall submit an annual report that summarizes its exports at the corporate level, except reporters may exclude shipments including less than twenty-five kilograms of fluorinated GHGs, fluorinated HTFs, or nitrous oxide; transshipments if the exporter also excludes transshipments from reporting of imports under paragraph (c) of this section; and heels if the exporter also excludes heels from any reporting of imports under paragraph (c) of this section. The report shall contain the following information for each export:

* * * * *

(4) Harmonized tariff system (HTS) code of the fluorinated GHGs, fluorinated HTFs, or nitrous oxide shipped.

* * * * *

(k) For nitrous oxide, saturated perfluorocarbons, sulfur hexafluoride, and fluorinated heat transfer fluids as defined at § 98.6, report the end use(s) for which each GHG or fluorinated HTF is transferred and the aggregated annual quantity of that GHG or fluorinated HTF in metric tons that is transferred to that end use application, if known.

Subpart PP—Suppliers of Carbon Dioxide

■ 80. Amend § 98.420 by adding paragraph (a)(4) to read as follows:

§ 98.420 Definition of the source category.

(a) * * *

(4) Facilities with process units, including but not limited to direct air capture (DAC), that capture a CO_2 stream from ambient air for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground.

* * * * *

■ 81. Amend § 98.422 by adding paragraph (e) to read as follows:

§ 98.422 GHGs to report.

* * * * *

(e) Mass of CO_2 captured from DAC process units.

(1) Mass of CO_2 captured from ambient air.

(2) Mass of CO_2 captured from any on-site heat and/or electricity generation, where applicable.

■ 82. Amend § 98.423 by revising paragraphs (a)(3)(i) introductory text and (a)(3)(ii) introductory text to read as follows:

§ 98.423 Calculating CO_2 supply.

(a) * * *

(3) * * *

(i) For facilities with production process units, DAC process units, or production wells that capture or extract a CO_2 stream and either measure it after segregation or do not segregate the flow, calculate the total CO_2 supplied in accordance with equation PP–3a to paragraph (a)(3)(i) of this section.

* * * * *

(ii) For facilities with production process units or DAC process units that capture a CO_2 stream and measure it ahead of segregation, calculate the total CO_2 supplied in accordance with equation PP–3b to paragraph (a)(3)(ii) of this section.

* * * * *

■ 83. Amend § 98.426 by:

■ a. Redesignating paragraphs (f)(12) and (13) as paragraphs (f)(13) and (14), respectively;

■ b. Adding new paragraph (f)(12);

■ c. Revising paragraph (h); and

■ d. Adding paragraph (i).

The additions and revision read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(f) * * *

(12) Geologic sequestration of carbon dioxide with enhanced oil recovery that is covered by subpart VV of this part.

* * * * *

(h) If you capture a CO_2 stream from a facility that is subject to this part and transfer CO_2 to any facilities that are subject to subpart RR or VV of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the facility that is the source of the captured CO_2 stream;

(2) Report each facility identification number associated with the annual GHG reports for each subpart RR and subpart VV facility to which CO_2 is transferred; and

(3) Report the annual quantity of CO_2 in metric tons that is transferred to each subpart RR and subpart VV facility.

(i) If you capture a CO_2 stream at a facility with a DAC process unit, report the annual quantity of on-site and off-site electricity and heat generated for each DAC process unit as specified in paragraphs (i)(1) through (3) of this section. The quantities specified in paragraphs (i)(1) through (3) of this section must be provided per energy source if known and must represent the electricity and heat used for the DAC process unit starting with air intake and ending with the compressed CO_2 stream (*i.e.,* the CO_2 stream ready for supply for commercial applications or, if maintaining custody of the stream, sequestration or injection of the stream underground).

(1) *Electricity excluding combined heat and power (CHP).* If electricity is provided to a dedicated meter for the DAC process unit, report the annual quantity of electricity consumed, in megawatt hours (MWh), and the information in paragraph (i)(1)(i) or (ii) of this section.

(i) If the electricity is sourced from a grid connection, report the following information:

(A) State where the facility with the DAC process unit is located.

(B) County where the facility with the DAC process unit is located.

(C) Name of the electric utility company that supplied the electricity as shown on the last monthly bill issued by the utility company during the reporting period.

(D) Name of the electric utility company that delivered the electricity. In states with regulated electric utility markets, this will generally be the same utility reported under paragraph (i)(1)(i)(C) of this section, but in states with deregulated electric utility markets, this may be a different utility company.

(E) Annual quantity of electricity consumed in MWh, calculated as the sum of the total energy usage values specified in all billing statements received during the reporting year. Most customers will receive 12 monthly billing statements during the reporting year. Many utilities bill their customers per kilowatt-hour (kWh); usage values on bills that are based on kWh should be divided by 1,000 to report the usage in MWh as required under this paragraph (i)(1)(i)(E).

(ii) If electricity is sourced from on-site or through a contractual mechanism for dedicated off-site generation, for each applicable energy source specified in paragraphs (i)(1)(ii)(A) through (G) of this section, report the annual quantity of electricity consumed, in MWh. If the on-site electricity source is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(A) Non-hydropower renewable sources including solar, wind, geothermal and tidal.

(B) Hydropower.

(C) Natural gas.

(D) Oil.

(E) Coal.

(F) Nuclear.

(G) Other.

(2) *Heat excluding CHP.* For each applicable energy source specified in paragraphs (i)(2)(i) through (vii) of this section, report the annual quantity of heat, steam, or other forms of thermal energy sourced from on-site or through a contractual mechanism for dedicated off-site generation, in megajoules (MJ). If the on-site heat source is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(i) Solar.

(ii) Geothermal.

(iii) Natural gas.

(iv) Oil.

(v) Coal.

(vi) Nuclear.

(vii) Other.

(3) *CHP—(i) Electricity from CHP.* If electricity from CHP is sourced from on-site or through a contractual mechanism for dedicated off-site generation, for each applicable energy source specified in paragraphs (i)(3)(i)(A) through (G) of this section, report the annual quantity consumed, in MWh. If the on-site electricity source for CHP is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(A) Non-hydropower renewable sources including solar, wind, geothermal and tidal.

(B) Hydropower.

(C) Natural gas.

(D) Oil.

(E) Coal.

(F) Nuclear.

(G) Other.

(ii) *Heat from CHP.* For each applicable energy source specified in paragraphs (i)(3)(ii)(A) through (G) of this section, report the quantity of heat, steam, or other forms of thermal energy from CHP sourced from on-site or through a contractual mechanism for dedicated off-site generation, in MJ. If the on-site heat source is natural gas, oil, or coal, also indicate whether flue gas is also captured by the DAC process unit.

(A) Solar.

(B) Geothermal.

(C) Natural gas.

(D) Oil.

(E) Coal.

(F) Nuclear.

(G) Other.

■ 84. Amend § 98.427 by revising paragraph (a) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(a) The owner or operator of a facility containing production process units or DAC process units must retain quarterly records of captured or transferred CO_2 streams and composition.

* * * * *

Subpart QQ—Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams

■ 85. Amend § 98.436 by adding paragraphs (a)(7) and (b)(7) to read as follows:

§ 98.436 Data reporting requirements.

(a) * * *

(7) The Harmonized tariff system (HTS) code for each type of pre-charged equipment or closed-cell foam imported.

(b) * * *

(7) The Schedule B code for each type of pre-charged equipment or closed-cell foam exported.

Subpart RR—Geologic Sequestration of Carbon Dioxide

■ 86. Amend § 98.449 by adding the definition ''Offshore'' in alphabetical order to read as follows:

§ 98.449 Definitions.

* * * * *

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

* * * * *

■ 87. Revise subpart SS consisting of §§ 98.450 through 98.458 to read as follows:

Subpart SS—Electrical Equipment Manufacture or Refurbishment

Sec.

98.450 Definition of the source category.
98.451 Reporting threshold.
98.452 GHGs to report.
98.453 Calculating GHG emissions.
98.454 Monitoring and QA/QC requirements.
98.455 Procedures for estimating missing data.
98.456 Data reporting requirements.
98.457 Records that must be retained.
98.458 Definitions.

§ 98.450 Definition of the source category.

The electrical equipment manufacturing or refurbishment category consists of processes that manufacture or refurbish gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers (including gas-containing components of such equipment) containing fluorinated GHGs, including but not limited to sulfur-hexafluoride (SF_6) and perfluorocarbons (PFCs). The processes include equipment testing, installation, manufacturing, decommissioning and disposal, refurbishing, and storage in gas cylinders and other containers.

§ 98.451 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an electrical equipment manufacturing or refurbishing process and the facility meets the requirements of § 98.2(a)(2). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in § 98.2(a)(2), follow the requirements of § 98.2(b), with one exception. Instead of following the requirement of § 98.453 to calculate emissions from electrical equipment manufacture or refurbishment, you must calculate emissions of each fluorinated GHG that is a component of a reportable insulating gas and then sum the emissions of each fluorinated GHG resulting from manufacturing and refurbishing electrical equipment using equation SS–1 to this section.

$$E = \sum_j \sum_i P_j * GHG_{i,w} * GWP_i * EF * 0.000453592 \qquad \text{(Eq. SS–1)}$$

Where:

E = Annual production process emissions for threshold applicability purposes (metric tons CO_2e).

P_j = Total annual purchases of reportable insulating gas j (lbs).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in reportable insulating gas j if reportable insulating gas j is a gas mixture. If not a mixture, use 1.

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

EF = Emission factor for electrical transmission and distribution equipment (lbs emitted/lbs purchased). For all gases, use an emission factor of 0.1.

i = Fluorinated GHG contained in the electrical transmission and distribution equipment.

0.000453592 = Conversion factor from lbs to metric tons.

§ 98.452 GHGs to report.

(a) You must report emissions of each fluorinated GHG, including but not limited to SF6 and PFCs, at the facility level, except you are not required to report emissions of fluorinated GHGs that are components of insulating gases whose weighted average GWPs, as calculated in equation SS–2 to this section, are less than or equal to one. You are, however, required to report certain quantities of insulating gases whose weighted average GWPs are less than or equal to one as specified in § 98.456(f), (g), (k) and (q) through (s). Annual emissions from the facility must include fluorinated GHG emissions from equipment that is installed at an off-site electric power transmission or distribution location whenever emissions from installation activities (*e.g.,* filling) occur before the title to the equipment is transferred to the electric power transmission or distribution entity.

$$GWP_j = \sum_i GHG_{i,w} * GWP_i \qquad \text{(Eq. SS–2)}$$

Where:

GWP_j = Weighted average GWP of insulating gas j.

$GHG_{i,w}$ = The weight fraction of GHG i in insulating gas j, expressed as a decimal. fraction. If GHG i is not part of a gas mixture, use a value of 1.0.

GWP_i = Gas-appropriate GWP as provided in table A–1 to subpart A of this part.

i = GHG contained in the electrical transmission and distribution equipment.

(b) You must report CO_2, N_2O and CH_4 emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part by following the requirements of subpart C of this part.

§ 98.453 Calculating GHG emissions.

(a) For each electrical equipment manufacturer or refurbisher, estimate the annual emissions of each fluorinated GHG that is a component of any reportable insulating gas using the mass-balance approach in equation SS–3 to this section:

$$\begin{aligned}&\text{User emissions}_i = \Sigma_j GHG_{i,w} * \\ &[(\text{Decrease in Inventory of Reportable Insulating Gas j Inventory}) + (\text{Acquisitions of Reportable} \\ &\text{Insulating Gas j}) - (\text{Disbursements of Reportable Insulating Gas j})] \qquad \text{(Eq. SS–3)}\end{aligned}$$

Where:

User emissions_i = Annual emissions of each fluorinated GHG i (pounds).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in reportable insulating gas j if insulating gas j is a gas mixture, expressed as a decimal fraction. If fluorinated GHG i is not part of a gas mixture, use a value of 1.0.

Decrease in Inventory of Reportable Insulating Gas j Inventory = (Pounds of reportable insulating gas j stored in containers at the beginning of the year)—(Pounds of reportable insulating gas j stored in containers at the end of the year).

Acquisitions of Reportable Insulating Gas j = (Pounds of reportable insulating gas j purchased from chemical producers or suppliers in bulk) + (Pounds of reportable insulating gas j returned by equipment users) + (Pounds of reportable insulating gas j returned to site after off-site recycling).

Disbursements of Reportable Insulating Gas j = (Pounds of reportable insulating gas j contained in new equipment delivered to customers) + (Pounds of reportable insulating gas j delivered to equipment users in containers) + (Pounds of reportable insulating gas j returned to suppliers) + (Pounds of reportable insulating gas j sent off site for recycling) + (Pounds of reportable insulating gas j sent off-site for destruction).

(b) [Reserved]

(c) Estimate the disbursements of reportable insulating gas j sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers using equation SS–4 to this section:

$$D_{GHG} = \sum_{p=1}^{n} Q_p \qquad \text{(Eq. SS–4)}$$

Where:

D_{GHG} = The annual disbursement of reportable insulating gas j sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

Q_p = The mass of reportable insulating gas j charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

n = The number of periods in the year.

(d) Estimate the mass of each insulating gas j disbursed to customers in new equipment or cylinders over the period p by monitoring the mass flow of each insulating gas j into the new equipment or cylinders using a flowmeter, or by weighing containers before and after gas from containers is used to fill equipment or cylinders, or by using the nameplate capacity of the equipment.

(e) If the mass of insulating gas j disbursed to customers in new equipment or cylinders over the period p is estimated by weighing containers before and after gas from containers is used to fill equipment or cylinders, estimate this quantity using equation SS–5 to this section:

$$Q_p = M_B - M_E - E_L \qquad \text{(Eq. SS–5)}$$

Where:

Q_p = The mass of insulating gas j charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

M_B = The mass of the contents of the containers used to fill equipment or cylinders at the beginning of period p.

M_E = The mass of the contents of the containers used to fill equipment or cylinders at the end of period p.

E_L = The mass of insulating gas j emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled).

(f) If the mass of insulating gas j disbursed to customers in new equipment or cylinders over the period p is determined using a flowmeter, estimate this quantity using equation SS–6 to this section:

$$Q_p = M_{mr} - E_L \qquad \text{(Eq. SS–6)}$$

Where:

Q_p = The mass of insulating gas j charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

M_{mr} = The mass of insulating gas j that has flowed through the flowmeter during the period p.

E_L = The mass of insulating gas j emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment that is being filled).

(g) Estimate the mass of insulating gas j emitted during the period p downstream of the containers used to fill equipment or cylinders (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled) using equation SS–7 to this section:

$$E_L = \sum_{j=0}^{n} F_{Ci} * EF_{Ci} \qquad \text{(Eq. SS–7)}$$

Where:

E_L = The mass of insulating gas j emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (*e.g.,* emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled).

FC_i = The total number of fill operations over the period p for the valve-hose combination Ci.

EF_{Ci} = The emission factor for the valve-hose combination Ci.

n=The number of different valve-hose combinations C used during the period p.

(h) If the mass of insulating gas j disbursed to customers in new equipment or cylinders over the period p is determined by using the nameplate capacity, or by using the nameplate capacity of the equipment and calculating the partial shipping charge, use the methods in either paragraph (h)(1) or (2) of this section.

(1) Determine the equipment's actual nameplate capacity, by measuring the nameplate capacities of a representative sample of each make and model and calculating the mean value for each make and model as specified at § 98.454(f).

(2) If equipment is shipped with a partial charge, calculate the partial shipping charge by multiplying the nameplate capacity of the equipment by the ratio of the densities of the partial charge to the full charge.

(i) Estimate the annual emissions of reportable insulating gas j from the equipment that is installed at an off-site electric power transmission or distribution location before the title to the equipment is transferred by using equation SS–8 to this section:

$$EI = GHG_{i,w} * (M_F + M_C - N_I) \qquad \text{Eq. SS–8}$$

Where:

EI = Total annual emissions of reportable insulating gas j from equipment installation at electric transmission or distribution facilities.

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in reportable insulating gas j if reportable insulating gas j is a gas mixture, expressed as a decimal fraction. If the GHG i is not part of a gas mixture, use a value of 1.0.

M_F = The total annual mass of reportable insulating gas j, in pounds, used to fill equipment during equipment installation at electric transmission or distribution facilities.

M_C = The total annual mass of reportable insulating gas j, in pounds, used to charge the equipment prior to leaving the electrical equipment manufacturer facility.

N_I = The total annual nameplate capacity of the equipment, in pounds, installed at electric transmission or distribution facilities.

§ 98.454 Monitoring and QA/QC requirements.

(a) [Reserved]

(b) Ensure that all the quantities required by the equations of this subpart have been measured using either flowmeters with an accuracy and precision of ±1 percent of full scale or better or scales with an accuracy and precision of ±1 percent of the filled weight (gas plus tare) of the containers of each reportable insulating gas that are typically weighed on the scale. For scales that are generally used to weigh cylinders containing 115 pounds of gas when full, this equates to ±1 percent of the sum of 115 pounds and approximately 120 pounds tare, or slightly more than ±2 pounds. Account 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) if the supplier provides documentation verifying that accuracy standards are met; however, you remain responsible for the accuracy of these masses and weights under this subpart.

(c) All flow meters, weigh scales, and combinations of volumetric and density measures that are used to measure or calculate quantities under this subpart must be calibrated using calibration procedures specified by the flowmeter, scale, volumetric or density measure equipment manufacturer. Calibration must be performed prior to the first reporting year. After the initial calibration, recalibration must be performed at the minimum frequency specified by the manufacturer.

(d) For purposes of equation SS–7 to § 98.453, the emission factor for the valve-hose combination (EFC) must be estimated using measurements and/or engineering assessments or calculations based on chemical engineering principles or physical or chemical laws or properties. Such assessments or calculations may be based on, as applicable, the internal volume of hose or line that is open to the atmosphere during coupling and decoupling activities, the internal pressure of the hose or line, the time the hose or line is open to the atmosphere during coupling and decoupling activities, the frequency with which the hose or line is purged and the flow rate during purges. You must develop a value for EFc (or use an industry-developed value) for each combination of hose and valve fitting, to use in equation SS–7 to § 98.453. The value for EFC must be determined for each combination of hose and valve fitting of a given diameter or size. The calculation must be recalculated annually to account for changes to the specifications of the valves or hoses that may occur throughout the year.

(e) Electrical equipment manufacturers and refurbishers must account for emissions of each reportable insulating gas that occur as a result of unexpected events or accidental losses, such as a malfunctioning hose or leak in the flow line, during the filling of equipment or containers for disbursement by including these losses in the estimated mass of each reportable insulating gas emitted downstream of the container or flowmeter during the period p.

(f) If the mass of each reportable insulating gas j disbursed to customers in new equipment over the period p is determined by assuming that it is equal to the equipment's nameplate capacity or, in cases where equipment is shipped with a partial charge, equal to its partial shipping charge, equipment samples for conducting the nameplate capacity tests must be selected using the following stratified sampling strategy in this paragraph (f). For each make and model, group the measurement conditions to reflect predictable variability in the facility's filling practices and conditions (*e.g.,* temperatures at which equipment is filled). Then, independently select equipment samples at random from each make and model under each group of conditions. To account for variability, a certain number of these measurements must be performed to develop a robust and representative average nameplate capacity (or shipping charge) for each make, model, and group of conditions. A Student T distribution calculation should be conducted to determine how many samples are needed for each make, model, and group of conditions as a function of the relative standard deviation of the sample measurements. To determine a sufficiently precise estimate of the nameplate capacity, the number of measurements required must be calculated to achieve a precision of one percent of the true mean, using a 95 percent confidence interval. To estimate the nameplate capacity for a given make and model, you must use the lowest mean value among the different groups of conditions, or provide justification for the use of a different mean value for the group of conditions that represents the typical practices and conditions for that make and model. Measurements can be conducted using SF6, another gas, or a liquid. Re-measurement of nameplate capacities should be conducted every five years to reflect cumulative changes in manufacturing methods and conditions over time.

(g) Ensure the following QA/QC methods are employed throughout the year:

(1) Procedures are in place and followed to track and weigh all cylinders or other containers at the beginning and end of the year.

(2) [Reserved]

(h) You must adhere to the following QA/QC methods for reviewing the completeness and accuracy of reporting:

(1) Review inputs to equation SS–3 to § 98.453 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 the inventory for each reportable insulating gas may be calculated as negative.

(3) Ensure that for each reportable insulating gas, the beginning-of-year inventory matches the end-of-year inventory from the previous year.

(4) Ensure that for each reportable insulating gas, in addition to the reportable insulating gas purchased from bulk gas distributors, the reportable insulating gas returned from equipment users with or inside equipment and the reportable insulating gas returned from off-site recycling are also accounted for among the total additions.

§ 98.455 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 similar manufacturing operations, and from similar equipment testing and decommissioning activities for which data are available.

§ 98.456 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each chemical at the facility level:

(a) Pounds of each reportable insulating gas stored in containers at the beginning of the year.

(b) Pounds of each reportable insulating gas stored in containers at the end of the year.

(c) Pounds of each reportable insulating gas purchased in bulk.

(d) Pounds of each reportable insulating gas returned by equipment users with or inside equipment.

(e) Pounds of each reportable insulating gas returned to site from off site after recycling.

(f) Pounds of each insulating gas inside new equipment delivered to customers.

(g) Pounds of each insulating gas delivered to equipment users in containers.

(h) Pounds of each reportable insulating gas returned to suppliers.

(i) Pounds of each reportable insulating gas sent off site for destruction.

(j) Pounds of each reportable insulating gas sent off site to be recycled.

(k) The nameplate capacity of the equipment, in pounds, delivered to customers with each insulating gas inside, if different from the quantity in paragraph (f) of this section.

(l) A description of the engineering methods and calculations used to determine emissions from hoses or other flow lines that connect the container to the equipment that is being filled.

(m) The values for EF_{ci} of equation SS–7 to § 98.453 for each hose and valve combination and the associated valve fitting sizes and hose diameters.

(n) The total number of fill operations for each hose and valve combination, or, FC_i of equation SS–7 to § 98.453.

(o) If the mass of each reportable insulating gas disbursed to customers in new equipment over the period p is determined according to the methods required in § 98.453(h), report the mean value of nameplate capacity in pounds for each make, model, and group of conditions.

(p) If the mass of each reportable insulating gas disbursed to customers in new equipment over the period p is determined according to the methods required in § 98.453(h), report the number of samples and the upper and lower bounds on the 95-percent confidence interval for each make, model, and group of conditions.

(q) Pounds of each insulating gas used to fill equipment at off-site electric power transmission or distribution locations, or MF, of equation SS–8 to § 98.453.

(r) Pounds of each insulating gas used to charge the equipment prior to leaving the electrical equipment manufacturer or refurbishment facility, or MC, of equation SS–8 to § 98.453.

(s) The nameplate capacity of the equipment, in pounds, installed at off-site electric power transmission or distribution locations used to determine emissions from installation, or N_I, of equation SS–8 to § 98.453.

(t) For any missing data, you must report the reason the data were missing, the parameters for which the data were missing, the substitute parameters used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

(u) For each insulating gas reported in paragraphs (a) through (j) and (o) through (r) of this section, an ID number or other appropriate descriptor unique to that insulating gas.

(v) For each ID number or descriptor reported in paragraph (u) of this section for each unique insulating gas, the name (as required in § 98.3(c)(4)(iii)(G)(*1*)) and weight percent of each fluorinated gas in the insulating gas.

§ 98.457 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) All information reported and listed in § 98.456.

(b) Accuracy certifications and calibration records for all scales and monitoring equipment, including the method or manufacturer's specification used for calibration.

(c) Certifications of the quantity of gas, in pounds, charged into equipment at the electrical equipment manufacturer or refurbishment facility as well as the actual quantity of gas, in pounds, charged into equipment at installation.

(d) Check-out and weigh-in sheets and procedures for cylinders.

(e) Residual gas amounts, in pounds, in cylinders sent back to suppliers.

(f) Invoices for gas purchases and sales.

(g) GHG Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011.

§ 98.458 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the CAA and subpart A of this part.

Insulating gas, for the purposes of this subpart, means any fluorinated GHG or fluorinated GHG mixture, including but not limited to SF_6 and PFCs, that is used as an insulating and/or arc-quenching gas in electrical equipment.

Reportable insulating gas, for purposes of this subpart, means an insulating gas whose weighted average GWP, as calculated in equation SS–2 to § 98.452, is greater than one. A fluorinated GHG that makes up either part or all of a reportable insulating gas is considered to be a component of the reportable insulating gas.

Subpart UU—Injection of Carbon Dioxide

■ 88. Revise and republish § 98.470 to read as follows:

§ 98.470 Definition of the source category.

(a) The injection of carbon dioxide (CO_2) source category comprises any well or group of wells that inject a CO_2 stream into the subsurface.

(b) If you report under subpart RR of this part for a well or group of wells, you shall not report under this subpart for that well or group of wells.

(c) If you report under subpart VV of this part for a well or group of wells, you shall not report under this subpart for that well or group of wells. If you previously met the source category definition for subpart UU of this part for a project where CO_2 is injected in enhanced recovery operations for oil and other hydrocarbons (CO_2–EOR) and then began using the standard designated as CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7) such that you met the definition of the source category for subpart VV during a reporting year, you must report under subpart UU for the portion of the year before you began using CSA/ANSI ISO 27916:19 and report under subpart VV for the portion of the year after you began using CSA/ANSI ISO 27916:19.

(d) A facility that is subject to this part only because it is subject to subpart UU of this part is not required to report emissions under subpart C of this part or any other subpart listed in § 98.2(a)(1) or (2).

■ 89. Add subpart VV consisting of §§ 98.480 through 98.489, subpart WW consisting of §§ 98.490 through 98.498, subpart XX consisting of §§ 98.500 through 98.508, subpart YY consisting of §§ 98.510 through 98.518, and subpart ZZ consisting of §§ 98.520 through 98.528 to part 98 to read as follows:

Subpart VV—Geologic Sequestration of Carbon Dioxide With Enhanced Oil Recovery Using ISO 27916

Sec.

§ 98.480 Definition of the source category.

(a) This source category pertains to carbon dioxide (CO_2) that is injected in enhanced recovery operations for oil and other hydrocarbons (CO_2–EOR) in which all of the following apply:

(1) You are using the standard designated as CSA/ANSI ISO 27916:19, (incorporated by reference, see § 98.7) as a method of quantifying geologic sequestration of CO_2 in association with EOR operations.

(2) You are not reporting under subpart RR of this part.

(b) This source category does not include wells permitted as Class VI under the Underground Injection Control program.

(c) If you are subject to only this subpart, you are not required to report emissions under subpart C of this part or any other subpart listed in § 98.2(a)(1) or (2).

§ 98.481 Reporting threshold.

(a) You must report under this subpart if your CO_2–EOR project uses CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7) as a method of quantifying geologic sequestration of CO_2 in association with CO_2–EOR operations. There is no threshold for reporting.

(b) The requirements of § 98.2(i) do not apply to this subpart. Once a CO_2–EOR project becomes subject to the requirements of this subpart, you must continue for each year thereafter to comply with all requirements of this subpart, including the requirement to submit annual reports until the facility has met the requirements of paragraphs (b)(1) and (2) of this section and submitted a notification to discontinue reporting according to paragraph (b)(3) of this section.

(1) Discontinuation of reporting under this subpart must follow the requirements set forth under Clause 10 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

(2) CO_2–EOR project termination is completed when all of the following occur:

(i) Cessation of CO_2 injection.

(ii) Cessation of hydrocarbon production from the project reservoir; and

(iii) Wells are plugged and abandoned unless otherwise required by the appropriate regulatory authority.

(3) You must notify the Administrator of your intent to cease reporting and provide a copy of the CO_2–EOR project termination documentation.

(c) If you previously met the source category definition for subpart UU of this part for your CO_2–EOR project and then began using CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7) as a method of quantifying geologic sequestration of CO_2 in association with CO_2–EOR operations during a reporting year, you must report under subpart UU of this part for the portion of the year before you began using CSA/ANSI ISO 27916:19 and report under subpart VV for the portion of the year after you began using CSA/ANSI ISO 27916:19.

§ 98.482 GHGs to report.

You must report the following from Clause 8 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7):

(a) The mass of CO_2 received by the CO_2–EOR project.

(b) The mass of CO_2 loss from the CO_2–EOR project operations.

(c) The mass of native CO_2 produced and captured.

(d) The mass of CO_2 produced and sent off-site.

(e) The mass of CO_2 loss from the EOR complex.

(f) The mass of CO_2 stored in association with CO_2–EOR.

§ 98.483 Calculating CO_2 geologic sequestration.

You must calculate CO_2 sequestered using the following quantification principles from Clause 8.2 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

(a) You must calculate the mass of CO_2 stored in association with CO_2–EOR (m_{stored}) in the reporting year by subtracting the mass of CO_2 loss from operations and the mass of CO_2 loss from the EOR complex from the total mass of CO_2 input (as specified in equation 1 to this paragraph (a)).

Equation 1 to paragraph (a)

$$m_{\text{stored}} = m_{\text{input}} - m_{\text{loss operations}} - m_{\text{loss EOR complex}}$$

Where:

m_{stored} = The annual quantity of associated storage in metric tons of CO_2 mass.

m_{input} = The total mass of CO_2 m_{received} by the EOR project plus m_{native} (see Clause 8.3 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7) and paragraph (c) of this section), metric tons. Native CO_2 produced and captured in the CO_2–EOR project (m_{native}) can be quantified and included in m_{input}.

$m_{\text{loss operations}}$ = The total mass of CO_2 loss from project operations (see Clauses 8.4.1 through 8.4.5 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7) and paragraph (d) of this section), metric tons.

$m_{\text{loss EOR complex}}$ = The total mass of CO_2 loss from the EOR complex (see Clause 8.4.6 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)), metric tons.

(b) The manner by which associated storage is quantified must assure completeness and preclude double counting. The annual mass of CO_2 that is recycled and reinjected into the EOR complex must not be quantified as associated storage. Loss from the CO_2 recycling facilities must be quantified.

(c) You must quantify the total mass of CO_2 input (m_{input}) in the reporting year according to paragraphs (g)(1) through (3) of this section.

(1) You must include the total mass of CO_2 received at the custody transfer meter by the CO_2–EOR project (m_{received}).

(2) The CO_2 stream received (including CO_2 transferred from another CO_2–EOR project) must be metered.

(i) The native CO_2 recovered and included as m_{native} must be documented.

(ii) CO_2 delivered to multiple CO_2–EOR projects must be allocated among those CO_2–EOR projects.

(3) The sum of the quantities of allocated CO_2 must not exceed the total quantities of CO_2 received.

(d) You must calculate the total mass of CO_2 from project operations ($m_{\text{loss operations}}$) in the reporting year as specified in equation 2 to this paragraph (d).

Equation 2 to paragraph (d)

$$m_{\text{loss operations}} = m_{\text{loss leakage facilites}} + m_{\text{loss}\frac{\text{vent}}{\text{flare}}} + m_{\text{loss entrained}} + m_{\text{loss transfer}}$$

Where:

$m_{\text{loss leakage facilities}}$ = Loss of CO_2 due to leakage from production, handling, and recycling CO_2–EOR facilities (infrastructure including wellheads), metric tons.

$m_{\text{loss vent/flare}}$ = Loss of CO_2 from venting/flaring from production operations, metric tons.

$m_{\text{loss entrained}}$ = Loss of CO_2 due to entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected, metric tons.

$m_{\text{loss transfer}}$=Loss of CO_2 due to any transfer of CO_2 outside the CO_2–EOR project, metric tons. You must quantify any CO_2 that is subsequently produced from the EOR complex and transferred offsite.

§ 98.484 Monitoring and QA/QC requirements.

You must use the applicable monitoring and quality assurance requirements set forth in Clause 6.2 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

§ 98.485 Procedures for estimating missing data.

Whenever the value of a parameter is unavailable or the quality assurance procedures set forth in § 98.484 cannot be followed, you must follow the procedures set forth in Clause 9.2 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

§ 98.486 Data reporting requirements.

In addition to the information required by § 98.3(c), the annual report shall contain the following information, as applicable:

(a) The annual quantity of associated storage in metric tons of CO_2 (m_{stored}).

(b) The density of CO_2 if volumetric units are converted to mass in order to be reported for annual quantity of CO_2 stored.

(c) The annual quantity of CO_2 input (m_{input}) and the information in paragraphs (c)(1) and (2) of this section.

(1) The annual total mass of CO_2 received at the custody transfer meter by the CO_2–EOR project, including CO_2

transferred from another CO_2–EOR project ($m_{received}$).

(2) The annual mass of native CO_2 produced and captured in the CO_2–EOR project (m_{native}).

(d) The annual mass of CO_2 that is recycled and reinjected into the EOR complex.

(e) The annual total mass of CO_2 loss from project operations ($m_{loss\ operations}$), and the information in paragraphs (e)(1) through (4) of this section.

(1) Loss of CO_2 due to leakage from production, handling, and recycling CO_2–EOR facilities (infrastructure including wellheads) ($m_{loss\ leakage\ facilities}$).

(2) Loss of CO_2 from venting/flaring from production operations ($m_{loss\ vent/flare}$).

(3) Loss of CO_2 due to entrainment within produced gas/oil/water when this CO2 is not separated and reinjected ($m_{loss\ entrained}$).

(4) Loss of CO_2 due to any transfer of CO_2 outside the CO_2–EOR project ($m_{loss\ transfer}$).

(f) The total mass of CO_2 loss from the EOR complex ($m_{loss\ EOR\ complex}$).

(g) Annual documentation that contains the following components as described in Clause 4.4 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7):

(1) The formulas used to quantify the annual mass of associated storage, including the mass of CO_2 delivered to the CO_2–EOR project and losses during the period covered by the documentation (see Clause 8 and Annex B of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(2) The methods used to estimate missing data and the amounts estimated as described in Clause 9.2 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

(3) The approach and method for quantification utilized by the operator, including accuracy, precision, and uncertainties (see Clause 8 and Annex B of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(4) A statement describing the nature of validation or verification including the date of review, process, findings, and responsible person or entity.

(5) Source of each CO_2 stream quantified as associated storage (see Clause 8.3 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(6) A description of the procedures used to detect and characterize the total CO_2 leakage from the EOR complex.

(7) If only the mass of anthropogenic CO_2 is considered for mstored, a description of the derivation and application of anthropogenic CO_2 allocation ratios for all the terms described in Clauses 8.1 to 8.4.6 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

(8) Any documentation provided by a qualified independent engineer or geologist, who certifies that the documentation provided, including the mass balance calculations as well as information regarding monitoring and containment assurance, is accurate and complete.

(h) Any changes made within the reporting year to containment assurance and monitoring approaches and procedures in the EOR operations management plan.

§ 98.487 Records that must be retained.

You must follow the record retention requirements specified by § 98.3(g). In addition to the records required by § 98.3(g), you must comply with the record retention requirements in Clause 9.1 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

§ 98.488 EOR Operations Management Plan.

(a) You must prepare and update, as necessary, a general EOR operations management plan that provides a description of the EOR complex and engineered system (see Clause 4.3(a) of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)), establishes that the EOR complex is adequate to provide safe, long-term containment of CO_2, and includes site-specific and other information including:

(1) Geologic characterization of the EOR complex.

(2) A description of the facilities within the CO_2–EOR project.

(3) A description of all wells and other engineered features in the CO_2–EOR project.

(4) The operations history of the project reservoir.

(5) The information set forth in Clauses 5 and 6 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

(b) You must prepare initial documentation at the beginning of the quantification period, and include the following as described in the EOR operations management plan:

(1) A description of the EOR complex and engineered systems (see Clause 5 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(2) The initial containment assurance (see Clause 6.1.2 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(3) The monitoring program (see Clause 6.2 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(4) The quantification method to be used (see Clause 8 and Annex B of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(5) The total mass of previously injected CO_2 (if any) within the EOR complex at the beginning of the CO_2–EOR project (see Clause 8.5 and Annex B of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7)).

(c) The EOR operation management plan in paragraph (a) of this section and initial documentation in paragraph (b) of this section must be submitted to the Administrator with the annual report covering the first reporting year that the facility reports under this subpart. In addition, any documentation provided by a qualified independent engineer or geologist, who certifies that the documentation provided is accurate and complete, must also be provided to the Administrator.

(d) If the EOR operations management plan is updated, the updated EOR management plan must be submitted to the Administrator with the annual report covering the first reporting year for which the updated EOR operation management plan is applicable.

§ 98.489 Definitions.

Except as provided in paragraphs (a) and (b) of this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Additional terms and definitions are provided in Clause 3 of CSA/ANSI ISO 27916:19 (incorporated by reference, see § 98.7).

Subpart WW—Coke Calciners

§ 98.490 Definition of the source category.

(a) A coke calciner is a process unit that heats petroleum coke to high temperatures for the purpose of removing impurities or volatile substances in the petroleum coke feedstock.

(b) This source category consists of rotary kilns, rotary hearth furnaces, or similar process units used to calcine petroleum coke and also includes afterburners or other emission control systems used to treat the coke calcining unit's process exhaust gas.

§ 98.491 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a coke calciner and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.492 GHGs to report.

You must report:

(a) CO_2, CH_4, and N_2O emissions from each coke calcining unit under this subpart.

(b) CO_2, CH_4, and N_2O emissions from auxiliary fuel used in the coke calcining unit and afterburner, if applicable, or other control system used to treat the coke calcining unit's process off-gas under subpart C of this part by following the requirements of subpart C.

§ 98.493 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in § 98.492(a) using the applicable methods in paragraph (b) of this section.

(b) For each coke calcining unit, calculate GHG emissions according to the applicable provisions in paragraphs (b)(1) through (4) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate and report CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part. Auxiliary fuel use CO_2 emissions should be calculated in accordance with subpart C of this part and subtracted from the CO_2 CEMS emissions to determine process CO_2 emissions. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part or follow the requirements of paragraph (b)(2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using monthly measurements and equation 1 to this paragraph (b)(2).

Equation 1 to paragraph (b)(2)

$$CO_2 = \frac{44}{12} \times \sum_{m=1}^{12} \left(M_{in,m} \times CC_{GC,m} - \left(M_{out,m} + M_{dust,m}\right) \times CC_{MPC,m}\right)$$

Where:

CO_2 = Annual CO_2 emissions (metric tons CO_2/year).

m = Month index.

$M_{in,m}$ = Mass of green coke fed to the coke calcining unit in month ''m'' from facility records (metric tons/year).

$CC_{GC.m}$ = Mass fraction carbon content of green coke fed to the coke calcining unit from facility measurement data in month ''m'' (metric ton carbon/metric ton green coke). If measurements are made more frequently than monthly, determine the monthly average as the arithmetic average for all measurements made during the calendar month.

$M_{out,m}$ = Mass of marketable petroleum coke produced by the coke calcining unit in month ''m'' from facility records (metric tons petroleum coke/year).

$M_{dust,m}$ = Mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit in month ''m'' from facility records (metric ton petroleum coke dust/year). For coke calcining units that recycle the collected dust, the mass of coke dust removed from the process is the mass of coke dust collected less the mass of coke dust recycled to the process.

$CC_{MPC,m}$ = Mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit in month ''m'' from facility measurement data (metric ton carbon/metric ton petroleum coke). If measurements are made more frequently than monthly, determine the monthly average as the arithmetic average for all measurements made during the calendar month.

44 = Molecular weight of CO_2 (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

(3) Calculate CH4 emissions using equation 2 to this paragraph (b)(3).

Equation 2 to paragraph (b)(3)

$$CH_4 = \left(CO_2 \times \frac{EmF_2}{EmF_1}\right)$$

Where:

CH_4 = Annual methane emissions (metric tons CH_4/year).

CO_2 = Annual CO_2 emissions calculated in paragraph (b)(1) or (2) of this section, as applicable (metric tons CO_2/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from table C–1 to subpart C of this part (kg CO_2/MMBtu).

EmF_2 = Default CH_4 emission factor for ''Petroleum Products (All fuel types in table C–1)'' from table C–2 to subpart C of this part (kg CH_4/MMBtu).

(4) Calculate N_2O emissions using equation 3 to this paragraph (b)(4).

Equation 3 to paragraph (b)(4)

$$N_2O = \left(CO_2 \times \frac{EmF_3}{EmF_1}\right)$$

Where:

N_2O = Annual nitrous oxide emissions (metric tons N_2O/year).

CO_2 = Annual CO_2 emissions calculated in paragraph (b)(1) or (2) of this section, as applicable (metric tons CO_2/year).

EmF_1 = Default CO_2 emission factor for petroleum coke from table C–1 to subpart C of this part (kg CO_2/MMBtu).

EmF_3 = Default N_2O emission factor for ''Petroleum Products (All fuel types in table C–1)'' from table C–2 to subpart C of this part (kg N_2O/MMBtu).

§ 98.494 Monitoring and QA/QC requirements.

(a) Flow meters, gas composition monitors, and heating value monitors that are associated with sources that use a CEMS to measure CO_2 emissions according to subpart C of this part or that are associated with stationary combustion sources must meet the applicable monitoring and QA/QC requirements in § 98.34.

(b) Determine the mass of petroleum coke monthly as required by equation 1 to § 98.493(b)(2) using mass measurement equipment meeting the requirements for commercial weighing equipment as described in NIST HB 44–2023 (incorporated by reference, see § 98.7). Calibrate the measurement device according to the procedures specified by NIST HB 44–2023 (incorporated by reference, see § 98.7) or the procedures specified by the manufacturer. Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(c) Determine the carbon content of petroleum coke as required by equation 1 § 98.493(b)(2) using any one of the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.

(1) ASTM D3176–15 (incorporated by reference, see § 98.7).

(2) ASTM D5291–16 (incorporated by reference, see § 98.7).

(3) ASTM D5373–21 (incorporated by reference, see § 98.7).

(d) The owner or operator must document the procedures used to ensure the accuracy of the monitoring systems used including but not limited to calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded.

§ 98.495 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 sample is not taken), a substitute data value for the missing parameter must be used in the calculations.

(a) For missing auxiliary fuel use data, use the missing data procedures in subpart C of this part.

(b) For each missing value of mass or carbon content of coke, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the ''after'' value is not obtained by the end of the reporting year, you may use the ''before'' value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period.

(c) For missing CEMS data, you must use the missing data procedures in § 98.35.

§ 98.496 Data reporting requirements.

In addition to the reporting requirements of § 98.3(c), you must report the information specified in paragraphs (a) through (i) of this section for each coke calcining unit.

(a) The unit ID number (if applicable).

(b) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.

(c) The calculated CO_2, CH_4, and N_2O annual process emissions, expressed in metric tons of each pollutant emitted.

(d) A description of the method used to calculate the CO_2 emissions for each unit (*e.g.,* CEMS or equation 1 to § 98.493(b)(2)).

(e) Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).

(f) Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons/year).

(g) Annual mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit from facility records (metric tons/year) and an indication of whether coke dust is recycled to the unit (*e.g.,* all dust is recycled, a portion of the dust is recycled, or none of the dust is recycled).

(h) Annual average mass fraction carbon content of green coke fed to the coke calcining unit from facility measurement data (metric tons C per metric ton green coke).

(i) Annual average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric tons C per metric ton petroleum coke).

§ 98.497 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) The records of all parameters monitored under § 98.494.

(b) The applicable verification software records as identified in this paragraph (b). You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (b)(1) through (5) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (b)(1) through (5) of this section.

(1) Monthly mass of green coke fed to the coke calcining unit from facility records (metric tons/year) (equation 1 to § 98.493(b)(2)).

(2) Monthly mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons/year) (equation 1 to § 98.493(b)(2)).

(3) Monthly mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit from facility records (metric tons/year) (equation 1 to § 98.493(b)(2)).

(4) Average monthly mass fraction carbon content of green coke fed to the coke calcining unit from facility measurement data (metric tons C per metric ton green coke) (equation 1 to § 98.493(b)(2)).

(5) Average monthly mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric tons C per metric ton petroleum coke) (equation 1 to § 98.493(b)(2)).

§ 98.498 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart XX—Calcium Carbide Production

§ 98.500 Definition of the source category.

The calcium carbide production source category consists of any facility that produces calcium carbide.

§ 98.501 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a calcium carbide production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.502 GHGs to report.

You must report:

(a) Process CO_2 emissions from each calcium carbide process unit or furnace used for the production of calcium carbide.

(b) CO_2, CH_4, and N_2O emissions from each stationary combustion unit following the requirements of subpart C of this part. You must report these emissions under subpart C of this part by following the requirements of subpart C.

§ 98.503 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each calcium carbide process unit not subject to paragraph (c) of this section using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(b) Calculate and report under this subpart the annual process CO_2 emissions from the calcium carbide process unit using the carbon mass balance procedure specified in paragraphs (b)(1) and (2) of this section.

(1) For each calcium carbide process unit, determine the annual mass of carbon in each carbon-containing input and output material for the calcium carbide process unit and estimate annual process CO_2 emissions from the calcium carbide process unit using equation 1 to this paragraph (b)(1). Carbon-containing input materials include carbon electrodes and carbonaceous reducing agents. If you document that a specific input or output material contributes less than 1 percent of the total carbon into or out of the process, you do not have to include the material in your calculation using equation 1.

Equation 1 to paragraph (b)(1)

$$\begin{aligned} E_{CO2} = {} & \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^i \left(M_{\text{reducing agent}_i} \times C_{\text{reducing agent}_i}\right) \\ & + \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^m \left(M_{\text{electrode}_m} \times C_{\text{electrode}_m}\right) \\ & - \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^k \left(M_{\text{product outgoing}_k} \times C_{\text{product outgoing}_k}\right) \\ & - \frac{44}{12} \times \frac{2000}{2205} \times \sum_1^l \left(M_{\text{non-product outgoing}_l} \times C_{\text{non-product outgoing}_l}\right) \end{aligned}$$

Where:

E_{CO2} = Annual process CO_2 emissions from an individual calcium carbide process unit (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

$M_{\text{reducing agent}_i}$ = Annual mass of reducing agent i fed, charged, or otherwise introduced into the calcium carbide process unit (tons).

$C_{\text{reducing agent}_i}$ = Carbon content in reducing agent i (percent by weight, expressed as a decimal fraction).

$M_{\text{electrode}_m}$ = Annual mass of carbon electrode m consumed in the calcium carbide process unit (tons).

$C_{\text{electrode}_m}$ = Carbon content of the carbon electrode m (percent by weight, expressed as a decimal fraction).

$M_{\text{product outgoing}_k}$ = Annual mass of alloy product k tapped from the calcium carbide process unit (tons).

$C_{\text{product outgoing}_k}$ = Carbon content in alloy product k (percent by weight, expressed as a decimal fraction).

$M_{\text{non-product outgoing}_l}$ = Annual mass of non-product outgoing material l removed from the calcium carbide unit (tons).

$C_{\text{non-product outgoing}}$ = Carbon content in non-product outgoing material l (percent by weight, expressed as a decimal fraction).

(2) Determine the combined annual process CO_2 emissions from the calcium carbide process units at your facility using equation 2 to this paragraph (b)(2).

Equation 2 to paragraph (b)(2)

$$CO_2 = \Sigma 1^k \, E_{CO2_k}$$

Where:

CO_2 = Annual process CO_2 emissions from calcium carbide process units at a facility used for the production of calcium carbide (metric tons).

E_{CO2_k} = Annual process CO_2 emissions calculated from calcium carbide process unit k calculated using equation 1 to paragraph (b)(1) of this section (metric tons).

k = Total number of calcium carbide process units at facility.

(c) If all GHG emissions from a calcium carbide process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, then the calculation methodology in paragraph (b) of this section must not be used to calculate process emissions. The owner or operator must report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§ 98.504 Monitoring and QA/QC requirements.

If you determine annual process CO_2 emissions using the carbon mass balance procedure in § 98.503(b), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO_2 emissions using equation 1 to § 98.503(b)(1) by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed, used, or produced in the calendar year using the methods specified in either paragraph (b)(1) or (2) of this section. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material inputs and outputs each year. The carbon content of the material must be analyzed at least annually using the standard methods (and their QA/QC procedures) specified in paragraphs (b)(2)(i) and (ii) of this section, as applicable.

(i) ASTM D5373–08 (incorporated by reference, see § 98.7), for analysis of carbonaceous reducing agents and carbon electrodes.

(ii) ASTM C25–06 (incorporated by reference, see § 98.7) for analysis of materials such as limestone or dolomite.

§ 98.505 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.503 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter must be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) If you determine CO_2 emissions for the calcium carbide process unit at your facility using the carbon mass balance procedure in § 98.503(b), 100 percent data availability is required for the carbon content of the input and output materials. You must repeat the test for average carbon contents of inputs according to the procedures in § 98.504(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of the inputs and outputs from all available process data or data used for accounting purposes, such as purchase records.

§ 98.506 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, as applicable:

(a) Annual facility calcium carbide production capacity (tons).

(b) The annual facility production of calcium carbide (tons).

(c) Total number of calcium carbide process units at facility used for production of calcium carbide.

(d) Annual facility consumption of petroleum coke (tons).

(e) Each end use of any calcium carbide produced and sent off site.

(f) If the facility produces acetylene on site, provide the information in paragraphs (f)(1) through (3) of this section.

(1) The annual production of acetylene at the facility (tons).

(2) The annual quantity of calcium carbide used for the production of acetylene at the facility (tons).

(3) Each end use of any acetylene produced on-site.

(g) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by § 98.36 for the Tier 4 Calculation Methodology and the information specified in paragraphs (g)(1) and (2) of this section.

(1) Annual CO_2 emissions (in metric tons) from each CEMS monitoring location measuring process emissions from the calcium carbide process unit.

(2) Identification number of each process unit.

(h) If a CEMS is not used to measure CO_2 process emissions, and the carbon mass balance procedure is used to determine CO_2 emissions according to the requirements in § 98.503(b), then you must report the information specified in paragraphs (h)(1) through (3) of this section.

(1) Annual process CO_2 emissions (in metric tons) from each calcium carbide process unit.

(2) List the method used for the determination of carbon content for each input and output material included in the calculation of annual process CO_2 emissions for each calcium carbide process unit (*i.e.,* supplier provided information, analyses of representative samples you collected).

(3) If you use the missing data procedures in § 98.505(b), you must report for each calcium carbide production process unit how monthly mass of carbon-containing inputs and outputs with missing data were determined and the number of months the missing data procedures were used.

§ 98.507 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 calcium carbide process unit, as applicable.

(a) If a CEMS is used to measure CO_2 emissions according to the requirements in § 98.503(a), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37 and the information specified in paragraphs (a)(1) through (3) of this section.

(1) Monthly calcium carbide process unit production quantity (tons).

(2) Number of calcium carbide processing unit operating hours each month.

(3) Number of calcium carbide processing unit operating hours in a calendar year.

(b) If the carbon mass balance procedure is used to determine CO_2 emissions according to the requirements in § 98.503(b)(2), then you must retain records for the information specified in paragraphs (b)(1) through (5) of this section.

(1) Monthly calcium carbide process unit production quantity (tons).

(2) Number of calcium carbide process unit operating hours each month.

(3) Number of calcium carbide process unit operating hours in a calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO_2 emissions (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO_2 emissions.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input and output to each calcium carbide process unit, including documentation of specific input or output materials excluded from equation 1 to § 98.503(b)(1) that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in a calcium carbide process 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.

(d) The applicable verification software records as identified in this paragraph (d). You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (d)(1) through (8) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (d)(1) through (8) of this section.

(1) Carbon content in reducing agent (percent by weight, expressed as a decimal fraction) (equation 1 to § 98.503(b)(1)).

(2) Annual mass of reducing agent fed, charged, or otherwise introduced into the calcium carbide process unit (tons) (equation 1 to § 98.503(b)(1)).

(3) Carbon content of carbon electrode (percent by weight, expressed as a decimal fraction) (equation 1 to § 98.503(b)(1)).

(4) Annual mass of carbon electrode consumed in the calcium carbide process unit (tons) (equation 1 to § 98.503(b)(1)).

(5) Carbon content in product (percent by weight, expressed as a decimal fraction) (equation 1 to § 98.503(b)(1)).

(6) Annual mass of product produced/tapped in the calcium carbide process unit (tons) (equation 1 to § 98.503(b)(1)).

(7) Carbon content in non-product outgoing material (percent by weight, expressed as a decimal fraction) (equation 1 to § 98.503(b)(1)).

(8) Annual mass of non-product outgoing material removed from calcium carbide process unit (tons) (equation 1 to § 98.503(b)(1)).

§ 98.508 Definitions.

All terms used of this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart YY—Caprolactam, Glyoxal, and Glyoxylic Acid Production

§ 98.510 Definition of the source category.

This source category includes any facility that produces caprolactam, glyoxal, or glyoxylic acid. This source category excludes the production of glyoxal through the LaPorte process (*i.e.,* the gas-phase catalytic oxidation of ethylene glycol with air in the presence of a silver or copper catalyst).

§ 98.511 Reporting threshold.

You must report GHG emissions under this subpart if your facility meets the requirements of either § 98.2(a)(1) or (2) and the definition of source category in § 98.510.

§ 98.512 GHGs to report.

(a) You must report N_2O process emissions from the production of caprolactam, glyoxal, and glyoxylic acid as required by this subpart.

(b) You must report under subpart C of this part the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit by following the requirements of subpart C of this part.

§ 98.513 Calculating GHG emissions.

(a) You must determine annual N_2O process emissions from each caprolactam, glyoxal, and glyoxylic acid process line using the appropriate default N_2O generation factor(s) from table 1 to this subpart, the site-specific N_2O destruction factor(s) for each N_2O abatement device, and site-specific production data according to paragraphs (b) through (e) of this section.

(b) You must determine the total annual amount of product *i* (caprolactam, glyoxal, or glyoxylic acid) produced on each process line *t* (metric tons product), according to § 98.514(b).

(c) If process line *t* exhausts to any N_2O abatement technology *j*, you must determine the destruction efficiency for each N_2O abatement technology according to paragraph (c)(1) or (2) of this section.

(1) Use the control device manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.

(d) If process line *t* exhausts to any N_2O abatement technology *j*, you must determine the abatement utilization factor for each N_2O abatement technology according to paragraph (d)(1) or (2) of this section.

(1) If the abatement technology *j* has no downtime during the year, use 1.

(2) If the abatement technology *j* was not operational while product *i* was being produced on process line *t*, calculate the abatement utilization factor according to equation 1 to this paragraph (d)(2).

Equation 1 to paragraph (d)(2)

$$AF_j = \frac{T_{i,j}}{T_i}$$

Where:

AF_j = Monthly abatement utilization factor of N_2O abatement technology *j* from process unit *t* (fraction of time that abatement technology is operating).

$T_{i,j}$ = Total number of hours during month that product *i* (caprolactam, glyoxal, or glyoxylic acid), was produced from process unit *t* during which N_2O abatement technology *j* was operational (hours).

T_i = Total number of hours during month that product *i* (caprolactam, glyoxal, or glyoxylic acid), was produced from process unit *t* (hours).

(e) You must calculate N_2O emissions for each product *i* from each process line *t* and each N_2O control technology *j* according to equation 2 to this paragraph (e).

Equation 2 to paragraph (e)

$$E_{N2Ot} = \sum_{i,j} \left[EF_i * P_i * \left(1 - \left(DE_j * AF_j\right)\right)\right] * 0.001$$

Where:

E_{N2Ot} = Monthly process emissions of N_2O, metric tons from process line *t*.

EF_i = N_2O generation factor for product *i* (caprolactam, glyoxal, or glyoxylic acid), kg N_2O/metric ton of product produced, as shown in table 1 to this subpart.

P_i = Monthly production of product *i*, (caprolactam, glyoxal, or glyoxylic acid), metric tons.

DE_j = Destruction efficiency of N_2O abatement technology type *j*, fraction (decimal fraction of N_2O removed from vent stream).

AF_j = Monthly abatement utilization factor for N_2O abatement technology type *j*, fraction, calculated using equation 1 to paragraph (d)(2) of this section.

0.001 = Conversion factor from kg to metric tons.

(f) You must determine the annual emissions combined from each process line at your facility using equation 3 to this paragraph (f):

Equation 3 to paragraph (f)

$$N_2O = \sum_{1}^{12} E_{N2Ot}$$

Where:

N_2O = Annual process N_2O emissions from each process line for product i (caprolactam, glyoxal, or glyoxylic acid) (metric tons).

E_{N2Ot} = Monthly process emissions of N_2O from each process line for product i (caprolactam, glyoxal, or glyoxylic acid) (metric tons).

§ 98.514 Monitoring and QA/QC requirements.

(a) You must determine the total monthly amount of caprolactam, glyoxal, and glyoxylic acid produced. These monthly amounts are determined according to the methods in paragraph (a)(1) or (2) of this section.

(1) Direct measurement of production (such as using flow meters, weigh scales, etc.).

(2) Existing plant procedures used for accounting purposes (*i.e.,* dedicated tank-level and acid concentration measurements).

(b) You must determine the annual amount of caprolactam, glyoxal, and glyoxylic acid produced. These annual amounts are determined by summing the respective monthly quantities determined in paragraph (a) of this section.

§ 98.515 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of caprolactam, glyoxal, or glyoxylic acid production, the substitute data must be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the N_2O abatement device, assuming that the operation is generally constant from year to year, the substitute data value should be the most recent quality-assured value.

§ 98.516 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 (j) of this section.

(a) Process line identification number.

(b) Annual process N_2O emissions from each process line according to paragraphs (b)(1) through (3) of this section.

(1) N_2O from caprolactam production (metric tons).

(2) N_2O from glyoxal production (metric tons).

(3) N_2O from glyoxylic acid production (metric tons).

(c) Annual production quantities from all process lines at the caprolactam, glyoxal, or glyoxylic acid production facility according to paragraphs (c)(1) through (3) of this section.

(1) Caprolactam production (metric tons).

(2) Glyoxal production (metric tons).

(3) Glyoxylic acid production (metric tons).

(d) Annual production capacity from all process lines at the caprolactam, glyoxal, or glyoxylic acid production facility, as applicable, in paragraphs (d)(1) through (3) of this section.

(1) Caprolactam production capacity (metric tons).

(2) Glyoxal production capacity (metric tons).

(3) Glyoxylic acid production capacity (metric tons).

(e) Number of process lines at the caprolactam, glyoxal, or glyoxylic acid production facility, by product, in paragraphs (e)(1) through (3) of this section.

(1) Total number of process lines producing caprolactam.

(2) Total number of process lines producing glyoxal.

(3) Total number of process lines producing glyoxylic acid.

(f) Number of operating hours in the calendar year for each process line at the caprolactam, glyoxal, or glyoxylic acid production facility (hours).

(g) N_2O abatement technologies used (if applicable) and date of installation of abatement technology at the caprolactam, glyoxal, or glyoxylic acid production facility.

(h) Monthly abatement utilization factor for each N_2O abatement technology for each process line at the caprolactam, glyoxal, or glyoxylic acid production facility.

(i) Number of times in the reporting year that missing data procedures were followed to measure production quantities of caprolactam, glyoxal, or glyoxylic acid (months).

(j) Annual percent N_2O emission reduction per chemical produced at the caprolactam, glyoxal, or glyoxylic acid production facility, as applicable, in paragraphs (j)(1) through (3) of this section.

(1) Annual percent N_2O emission reduction for all caprolactam production process lines.

(2) Annual percent N_2O emission reduction for all glyoxal production process lines.

(3) Annual percent N_2O emission reduction for all glyoxylic acid production process lines.

§ 98.517 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 (d) of this section for each caprolactam, glyoxal, or glyoxylic acid production facility:

(a) Documentation of how accounting procedures were used to estimate production rate.

(b) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency (if applicable).

(c) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(d) The applicable verification software records as identified in this paragraph (d). You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (d)(1) through (4) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (d)(1) through (4) of this section.

(1) Monthly production quantity of caprolactam from each process line at the caprolactam, glyoxal, or glyoxylic acid production facility (metric tons).

(2) Monthly production quantity of glyoxal from each process line at the caprolactam, glyoxal, or glyoxylic acid production facility (metric tons).

(3) Monthly production quantity of glyoxylic acid from each process line at the caprolactam, glyoxal, or glyoxylic acid production facility (metric tons).

(4) Destruction efficiency of N_2O abatement technology from each process line, fraction (decimal fraction of N_2O removed from vent stream).

§ 98.518 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE 1 TO SUBPART YY OF PART 98—N_2O GENERATION FACTORS

Product	N_2O generation factor [a]
Caprolactam	9.0
Glyoxal	520

TABLE 1 TO SUBPART YY OF PART 98—N_2O GENERATION FACTORS—Continued

Product	N_2O generation factor [a]
Glyoxylic acid	100

[a] Generation factors in units of kilograms of N_2O emitted per metric ton of product produced.

Subpart ZZ—Ceramics Manufacturing

Sec.
98.520 Definition of the source category.
98.521 Reporting threshold.
98.522 GHGs to report.
98.523 Calculating GHG emissions.
98.524 Monitoring and QA/QC requirements.
98.525 Procedures for estimating missing data.
98.526 Data reporting requirements.
98.527 Records that must be retained.
98.528 Definitions.
Table 1 to Subpart ZZ of Part 98—CO_2 Emission Factors for Carbonate-Based Raw Materials

§ 98.520 Definition of the source category.

(a) The ceramics manufacturing source category consists of any facility that uses nonmetallic, inorganic materials, many of which are clay-based, to produce ceramic products such as bricks and roof tiles, wall and floor tiles, table and ornamental ware (household ceramics), sanitary ware, refractory products, vitrified clay pipes, expanded clay products, inorganic bonded abrasives, and technical ceramics (*e.g.,* aerospace, automotive, electronic, or biomedical applications). For the purposes of this subpart, ceramics manufacturing processes include facilities that annually consume at least 2,000 tons of carbonates, either as raw materials or as a constituent in clay, which is heated to a temperature sufficient to allow the calcination reaction to occur, and operate a ceramics manufacturing process unit.

(b) A ceramics manufacturing process unit is a kiln, dryer, or oven used to calcine clay or other carbonate-based materials for the production of a ceramics product.

§ 98.521 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a ceramics manufacturing process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.522 GHGs to report.

You must report:

(a) CO_2 process emissions from each ceramics process unit (*e.g.,* kiln, dryer, or oven).

(b) CO_2 combustion emissions from each ceramics process unit.

(c) CH_4 and N_2O combustion emissions from each ceramics process unit. You must calculate and report these emissions under subpart C of this part by following the requirements of subpart C of this part.

(d) CO_2, CH_4, and N_2O combustion emissions from each stationary fuel combustion unit other than kilns, dryers, or ovens. You must report these emissions under subpart C of this part by following the requirements of subpart C of this part.

§ 98.523 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each ceramics process unit using the procedures in paragraphs (a) through (c) of this section.

(a) For each ceramics process unit that meets the conditions specified in § 98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(b) For each ceramics process unit that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the ceramics process unit separately by using the procedures specified in paragraphs (b)(1) through (6) of this section, except as specified in paragraph (c) of this section.

(1) For each carbonate-based raw material (including clay) charged to the ceramics process unit, either obtain the mass fractions of any carbonate-based minerals from the supplier of the raw material or by sampling the raw material, or use a default value of 1.0 as the mass fraction for the raw material.

(2) Determine the quantity of each carbonate-based raw material charged to the ceramics process unit.

(3) Apply the appropriate emission factor for each carbonate-based raw material charged to the ceramics process unit. Table 1 to this subpart provides emission factors based on stoichiometric ratios for carbonate-based minerals.

(4) Use equation 1 to this paragraph (b)(4) to calculate process mass emissions of CO_2 for each ceramics process unit:

Equation 1 to paragraph (b)(4)

$$E_{CO2} = \sum_j \left[\left(M_j \bullet \frac{2000}{2205} \right) \bullet \sum_i (MF_i \bullet EF_i \bullet F_i) \right]$$

Where:

E_{CO2} = Annual process CO_2 emissions (metric tons/year).
M_j = Annual mass of the carbonate-based raw material *j* consumed (tons/year).
2000/2205 = Conversion factor to convert tons to metric tons.
MF_i = Annual average decimal mass fraction of carbonate-based mineral *i* in carbonate-based raw material *j*.
EF_i = Emission factor for the carbonate-based mineral *i*, (metric tons CO_2/metric ton carbonate, see table 1 to this subpart).
F_i = Decimal fraction of calcination achieved for carbonate-based mineral *i*, assumed to be equal to 1.0.
i = Index for carbonate-based mineral in each carbonate-based raw material.
j = Index for carbonate-based raw material.

(5) Determine the combined annual process CO_2 emissions from the ceramic process units at your facility using equation 2 to this paragraph (b)(5):

Equation 2 to paragraph (b)(5)

$$CO_2 = \Sigma^k{}_1 E_{CO2_k}$$

Where:

CO_2 = Annual process CO_2 emissions from ceramic process units at a facility (metric tons).
E_{CO2_k} = Annual process CO_2 emissions calculated from ceramic process unit k calculated using equation 1 to paragraph (b)(4) of this section (metric tons).
k = Total number of ceramic process units at facility.

(6) Calculate and report under subpart C of this part the combustion CO_2 emissions in the ceramics process unit according to the applicable requirements in subpart C of this part.

(c) A value of 1.0 can be used for the mass fraction (MF_i) of carbonate-based mineral i in each carbonate-based raw material *j* in equation 1 to paragraph (b)(4) of this section. The use of 1.0 for the mass fraction assumes that the carbonate-based raw material comprises 100% of one carbonate-based mineral. As an alternative to the default value, you may use data provided by either the raw material supplier or a lab analysis.

§ 98.524 Monitoring and QA/QC requirements.

(a) You must measure annual amounts of carbonate-based raw materials charged to each ceramics process unit from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to ceramics process units at the facility must be compared to records of raw material purchases for the year.

(b) You must use the default value of 1.0 for the mass fraction of a carbonate-based mineral, or you may opt to obtain the mass fraction of any carbonate-based materials from the supplier of the raw material or by sampling the raw material. If you opt to obtain the mass fractions of any carbonate-based minerals from the supplier of the raw material or by sampling the raw material, you must measure the carbonate-based mineral mass fractions at least annually to verify the mass fraction data. You may conduct the sampling and chemical analysis using any x-ray fluorescence test, x-ray diffraction test, or other enhanced testing method published by an industry consensus standards organization (*e.g.,* ASTM, ASME, API). If it is determined that the mass fraction of a carbonate based raw material is below the detection limit of available industry testing standards, you may use a default value of 0.005.

(c) You must use the default value of 1.0 for the mass fraction of a carbonate-based mineral, or you may opt to obtain the mass fraction of any carbonate-based materials from the supplier of the raw material or by sampling the raw material. If you obtain the mass fractions of any carbonate-based minerals from the supplier of the raw material or by sampling the raw material, you must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material at least annually by calculating an arithmetic average of the data obtained from raw material suppliers or sampling and chemical analysis.

(d) You must use the default value of 1.0 for the calcination fraction of a carbonate-based mineral. Alternatively, you may opt to obtain the calcination fraction of any carbonate-based mineral by sampling. If you opt to obtain the calcination fraction of any carbonate-based minerals from sampling, you must determine on an annual basis the calcination fraction for each carbonate-based mineral consumed based on sampling and chemical analysis. You may conduct the sampling and chemical analysis using any x-ray fluorescence test, x-ray diffraction test, or other enhanced testing method published by an industry consensus standards organization (*e.g.,* ASTM, ASME, API).

§ 98.525 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.523 is required. If the monitoring and quality assurance procedures in § 98.524 cannot be followed and data is unavailable, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section in the calculations. You must document and keep records of the procedures used for all such missing value estimates.

(a) If the CEMS approach is used to determine combined process and combustion CO_2 emissions, the missing data procedures in § 98.35 apply.

(b) For missing data on the monthly amounts of carbonate-based raw materials charged to any ceramics process unit, use the best available estimate(s) of the parameter(s) based on all available process data or data used for accounting purposes, such as purchase records.

(c) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials, assume that the mass fraction of a carbonate-based mineral is 1.0, which assumes that one carbonate-based mineral comprises 100 percent of the carbonate-based raw material.

§ 98.526 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 (c) of this section, as applicable:

(a) The total number of ceramics process units at the facility and the number of units that operated during the reporting year.

(b) If a CEMS is used to measure CO_2 emissions from ceramics process units, then you must report under this subpart the relevant information required under § 98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (b)(1) through (3) of this section.

(1) The annual quantity of each carbonate-based raw material (including clay) charged to each ceramics process unit and for all units combined (tons).

(2) Annual quantity of each type of ceramics product manufactured by each ceramics process unit and by all units combined (tons).

(3) Annual production capacity for each ceramics process unit (tons).

(c) If a CEMS is not used to measure CO_2 emissions from ceramics process units and process CO_2 emissions are calculated according to the procedures specified in § 98.523(b), then you must report the following information specified in paragraphs (c)(1) through (7) of this section.

(1) Annual process emissions of CO_2 (metric tons) for each ceramics process unit and for all units combined.

(2) The annual quantity of each carbonate-based raw material (including clay) charged to each ceramics process unit and for all units combined (tons).

(3) Results of all tests used to verify each carbonate-based mineral mass fraction for each carbonate-based raw material charged to a ceramics process unit, as specified in paragraphs (c)(3)(i) through (iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(4) Method used to determine the decimal mass fraction of carbonate-based mineral, unless you used the default value of 1.0 (*e.g.,* supplier provided information, analyses of representative samples you collected, or use of a default value of 0.005 as specified by § 98.524(b)).

(5) Annual quantity of each type of ceramics product manufactured by each ceramics process unit and by all units combined (tons).

(6) Annual production capacity for each ceramics process unit (tons).

(7) If you use the missing data procedures in § 98.525(b), you must report for each applicable ceramics process unit the number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals (months).

§ 98.527 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 ceramics process unit, as applicable.

(a) If a CEMS is used to measure CO_2 emissions according to the requirements in § 98.523(a), then you must retain under this subpart the records required under § 98.37 for the Tier 4 Calculation Methodology and the information specified in paragraphs (a)(1) and (2) of this section.

(1) Monthly ceramics production rate for each ceramics process unit (tons).

(2) Monthly amount of each carbonate-based raw material charged to each ceramics process unit (tons).

(b) If process CO_2 emissions are calculated according to the procedures specified in § 98.523(b), you must retain the records in paragraphs (b)(1) through (6) of this section.

(1) Monthly ceramics production rate for each ceramics process unit (metric tons).

(2) Monthly amount of each carbonate-based raw material charged to each ceramics process unit (metric tons).

(3) Data on carbonate-based mineral mass fractions provided by the raw material supplier for all raw materials consumed annually and included in calculating process emissions in equation 1 to § 98.523(b)(4), if applicable.

(4) Results of all tests, if applicable, used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a ceramics process unit, including the data specified in paragraphs (b)(4)(i) through (v) of this section.

(i) Date of test.

(ii) Method(s), and any variations of methods, used in the analyses.

(iii) Mass fraction of each sample analyzed.

(iv) Relevant calibration data for the instrument(s) used in the analyses.

(v) Name and address of laboratory that conducted the tests.

(5) Each carbonate-based mineral mass fraction for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(6) Number of annual operating hours of each ceramics process unit.

(c) All other documentation used to support the reported GHG emissions.

(d) The applicable verification software records as identified in this paragraph (d). You must keep a record of the file generated by the verification software specified in § 98.5(b) for the applicable data specified in paragraphs (d)(1) through (3) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (d)(1) through (3) of this section.

(1) Annual average decimal mass fraction of each carbonate-based mineral in each carbonate-based raw material for each ceramics process unit (specify the default value, if used, or the value determined according to § 98.524) (percent by weight, expressed as a decimal fraction) (equation 1 to § 98.523(b)(4)).

(2) Annual mass of each carbonate-based raw material charged to each ceramics process unit (tons) (equation 1 to § 98.523(b)(4)).

(3) Decimal fraction of calcination achieved for each carbonate-based raw material for each ceramics process unit (specify the default value, if used, or the value determined according to § 98.524) (percent by weight, expressed as a decimal fraction) (equation 1 to § 98.523(b)(4)).

§ 98.528 Definitions.

All terms used of this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE 1 TO SUBPART ZZ OF PART 98—CO_2 EMISSION FACTORS FOR CARBONATE-BASED RAW MATERIALS

Carbonate	Mineral name(s)	CO_2 emission factor [a]
$BaCO_3$	Witherite, Barium carbonate	0.223
$CaCO_3$	Limestone, Calcium Carbonate, Calcite, Aragonite	0.440
$Ca(Fe,Mg,Mn)(CO_3)_2$	Ankerite [b]	0.408–0.476
$CaMg(CO_3)_2$	Dolomite	0.477
$FeCO_3$	Siderite	0.380
K_2CO_3	Potassium carbonate	0.318
Li_2CO_3	Lithium carbonate	0.596
$MgCO_3$	Magnesite	0.522
$MnCO_3$	Rhodochrosite	0.383
Na_2CO_3	Sodium carbonate, Soda ash	0.415
$SrCO_3$	Strontium carbonate, Strontianite	0.298

[a] Emission factors are in units of metric tons of CO_2 emitted per metric ton of carbonate-based material.

[b] Ankerite emission factors are based on a formula weight range that assumes Fe, Mg, and Mn are present in amounts of at least 1.0 percent.

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