ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 98

[EPA–HQ–OAR–2019–0424; FRL–7230–02–OAR]

RIN 2060–AU35

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to amend specific provisions in the Greenhouse Gas Reporting Rule to improve the quality and consistency of the data collected under the rule, streamline and improve implementation, and clarify or propose minor updates to certain provisions that have been the subject of questions from reporting entities. These proposed changes include revisions to improve the existing calculation, recordkeeping, and reporting requirements by incorporating updates to existing emissions estimation methodologies and providing for collection of additional data to understand new source categories or new emission sources for specific sectors. The proposed changes would improve understanding of the sector-specific processes or other factors that influence greenhouse gas emissions rates, improve verification of collected data, and complement or inform other EPA programs. The EPA is also proposing revisions that would improve implementation of the Greenhouse Gas Reporting Rule such as updates to applicability estimation methodologies, providing flexibility for or simplifying calculation and monitoring methodologies, streamlining recordkeeping and reporting, and other minor technical corrections or clarifications. This action also proposes to establish and amend confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these proposed amendments. Further, this action includes a request for comment to solicit information that may aid in potential future revisions to the Greenhouse Gas Reporting Rule.

DATES:

Comments. Comments must be received on or before August 22, 2022. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before August 22, 2022.

Public hearing. The EPA does not plan to conduct a public hearing unless requested. If anyone contacts us requesting a public hearing on or before June 27, 2022, we will hold a virtual public hearing. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES:

Comments. You may submit your comments, identified by Docket Id. No. EPA–HQ–OAR–2019–0424, by any of the following methods:

Federal eRulemaking Portal: https://www.regulations.gov (our preferred method). Follow the online instructions for submitting comments.

Mail: U.S. Environmental Protection Agency, EPA Docket Center, Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.

Hand Delivery or Courier (by scheduled appointment only): EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m.–4:30 p.m., Monday–Friday (except federal holidays).

Instructions: All submissions received must include the Docket Id. No. for this proposed rulemaking. Comments received may be posted without change to *https://www.regulations.gov/,* including any personal information provided. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are closed to the public, with limited exceptions, to reduce the risk of transmitting Coronavirus 2019 (COVID–19). Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. We encourage the public to submit comments via *https://www.regulations.gov/* or email, as there may be a delay in processing mail and faxes. Hand deliveries and couriers may be received by scheduled appointment only. For further information on EPA Docket Center services and the current status, please visit us online at *https://www.epa.gov/dockets.*

Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

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, *https://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 proposal will also be available through the WWW. Following the Administrator's signature, a copy of this proposed rule will be posted on the EPA's GHGRP website at *https://www.epa.gov/ghgreporting.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. Please note that the EPA is deviating from its typical approach for public hearings because the President has declared a national emergency. Due to the current Centers for Disease Control and Prevention (CDC) recommendations, as well as state and local orders for social distancing to limit the spread of COVID–19, the EPA cannot hold in-person public meetings at this time.

To request a hearing, please contact the person listed in the following **FOR FURTHER INFORMATION CONTACT** section by June 27, 2022. If requested, the virtual hearing will be held on July 6, 2022. The hearing will convene at 9 a.m. Eastern Time (ET) and will conclude at 3 p.m. ET. The EPA may close the hearing 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will provide further information about the hearing on its website (*https://www.epa.gov/ghgreporting*) if a hearing is requested.

Upon publication of this document in the **Federal Register** (FR), the EPA will begin pre-registering speakers for the hearing, if a hearing is requested. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/ghgreporting.* If you have questions regarding registration, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section. The last day to pre-register to speak at the hearing will be July 5, 2022. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: *https://www.epa.gov/ghgreporting.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 5 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *GHGReporting@epa.gov.* The EPA also recommends submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/ghgreporting.* While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact us by email at *GHGReporting@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by June 28, 2022. The EPA may not be able to arrange accommodations without advanced notice.

Regulated entities. These proposed revisions would affect certain entities that must submit annual greenhouse gas (GHG) reports under the GHGRP (40 CFR part 98). These are proposed amendments to existing regulations. If finalized, these amended regulations would also affect owners or operators of certain 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	NAICS	Examples of affected facilities
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.
Ammonia Manufacturing	325311	Anhydrous and aqueous ammonia manufacturing facilities.
Cement Production	327310	Portland cement manufacturing plants.
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.
Ferroalloy Production	331110	Ferroalloys manufacturing facilities.
Fluorinated Greenhouse Gas Production	325120	Industrial gases manufacturing facilities.
Glass Production	327211	Flat glass manufacturing facilities.
	327213	Glass container manufacturing facilities.
	327212	Other pressed and blown glass and glassware manufacturing facilities.
Hydrogen Production	325120	Hydrogen manufacturing facilities.
Iron and Steel Production	333110	Integrated iron and steel mills, steel companies, sinter plants, blast furnaces, basic oxygen process furnace (BOPF) shops.
Lime Manufacturing	327410	Calcium oxide, calcium hydroxide, dolomitic hydrates manufacturing facilities.
Miscellaneous Uses of Carbonate	Facilities included elsewhere.	
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	325110	Ethylene dichloride manufacturing facilities.
	325199	Acrylonitrile, ethylene oxide, methanol manufacturing facilities.
	325110	Ethylene manufacturing facilities.
	325180	Other basic inorganic chemical manufacturing.
Petroleum Refineries	324110	Petroleum refineries.
Silicon Carbide Production	327910	Silicon carbide abrasives manufacturing facilities.
Electrical Equipment Use	221121	Electric bulk power transmission and control facilities.

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY—Continued

Category	NAICS	Examples of affected facilities
Underground Coal Mines	212113	Underground anthracite coal mining operations.
	212112	Underground bituminous coal mining operations.
Zinc Production	331419	Primary zinc refining facilities.
	331492	Zinc dust recycling facilities, recovering from scrap and/or alloying purchased metals.
	311411	Frozen fruit, juice, and vegetable manufacturing facilities.
	311421	Fruit and vegetable canning facilities.
Municipal Solid Waste Landfills	562212	Solid waste landfills.
	221320	Sewage treatment facilities.
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.
Electrical Equipment Manufacture or Refurbishment.	33531	Power transmission and distribution switchgear and specialty transformers manufacturing facilities.
Carbon Dioxide Enhanced Oil Recovery Projects.	211	Oil and gas extraction projects using carbon dioxide enhanced oil recovery.
Calcium Carbide Production	325180	Other basic inorganic chemical manufacturing.
Coke Calcining	324199	All other petroleum and coal products manufacturing.
Glyoxal, Glyoxylic Acid, and Caprolactam Production.	325199	All other basic organic chemical manufacturing.
Ceramics Manufacturing	327110	Pottery, ceramics, and plumbing fixture manufacturing.
	327120	Clay building material and refractories manufacturing.

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 proposed action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you would be affected by this proposed 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.

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

AGA American Gas Association
AIM American Innovation and Manufacturing Act of 2020
AMLD Advanced Mobile Leak Detection
ANOVA analysis of variance
ANSI American National Standards Institute
API American Petroleum Institute
ASTM American Society for Testing and Materials
BAMM best available monitoring methods
BEF by-product emission factor
BOEM Bureau of Ocean Energy Management
BOPF basic oxygen process furnace
C&D construction and demolition
CAA Clean Air Act
CARB California Air Resources Board
CBI confidential business information
CBP U.S. Customs and Border Protection
CCUS carbon capture, utilization, and sequestration
CDA clean dry air
CDC Centers for Disease Control and Prevention
CEMS continuous emission monitoring system
CFR Code of Federal Regulations
CGA cylinder gas audit
CF$_4$ perfluoromethane
CH$_4$ methane
CKD cement kiln dust
CO$_2$ carbon dioxide
CO$_2$e carbon dioxide equivalent
CO carbon monoxide
COF$_2$ carbonic difluoride
COVID–19 Coronavirus 2019
CSA CSA Group
CVD chemical vapor deposition
DAC direct air capture
DCU delayed coking unit
DOC degradable organic carbon
DOT Department of Transportation
DRE destruction or removal efficiency
e-GGRT electronic Greenhouse Gas Reporting Tool
EAF electric arc furnace
EDC ethylene dichloride
EF emission factor
EG emission guidelines
EIA Energy Information Administration
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
EREF Environmental Research and Education Foundation
ET Eastern time
FAQ frequently asked question
FR Federal Register
F–GHG fluorinated greenhouse gas
F–HTFs fluorinated heat transfer fluids
FTIR Fourier Transform Infrared
GCS gas collection system
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GIE gas-insulated equipment
GIS geographic information systems
GOR gas-to-oil ratio
GRI Gas Research Institute
GWP global warming potential
HCFC hydrochlorofluorocarbons
HFC hydrofluorocarbons
HHV high heating value
HTS Harmonized Tariff System
HVAE high voltage anode effect
IAI International Aluminium Institute
ICR Information Collection Request
IPCC Intergovernmental Panel on Climate Change
IRC Internal Revenue Code
IRS Internal Revenue Service
ISBN International Standard Book Number
ISO International Standards Organization
IVT Inputs Verification Tool
k first order decay rate
kg kilograms
LCA life cycle analysis
LCD liquid crystal display
LDC local distribution company
LNG liquified natural gas
LVAE low voltage anode effect
MCF moisture correction factor
MDEA methyl diethanolamine
MEA monoethanolamine
MEMS microelectromechanical systems
mmBtu/hr million British thermal units per hour
MMscf million standard cubic feet
MRV monitoring, reporting, and verification plan
MSHA Mine Safety and Health Administration
MSW municipal solid waste
mtCO$_2$e metric tons carbon dioxide equivalent

N_2O	nitrous oxide
NAICS	North American Industry Classification System
NGLs	natural gas liquids
NSPS	New Source Performance Standards
OAR	Office of Air and Radiation
OEM	original equipment manufacturer
OGI	optical gas imaging
OMB	Office of Management and Budget
OMP	operations management plan
PCA	Portland Cement Association
PFC	perfluorocarbon
PRA	Paperwork Reduction Act
ppmv	parts per million by volume
PV	photovoltaic
QA/QC	quality assurance/quality control
QMS	Quadrupole Mass Spectroscopy
RFA	Regulatory Flexibility Act
RMA	Rubber Manufacturers Association
RPC	remote plasma cleaning
RY	reporting year
scfh	standard cubic feet per hour
SF_6	sulfur hexafluoride
SIA	Semiconductor Industry Association
SIC	Standard Industrial Classification System
SSM	startup, shutdown, and malfunction
TBD	to be determined
TFI	The Fertilizer Institute
TSCA	Toxic Substances Control Act
TSD	technical support document
UIC	underground injection control
U.S.	United States
UMRA	Unfunded Mandates Reform Act of 1995
USGS	U.S. Geological Survey
USTMA	U.S. Tire Manufacturers Association
VCM	vinyl chloride monomer
VOC	volatile organic compound
WMO	World Meteorological Organization
WWW	World Wide Web

Table of Contents

I. Background

A. How is this preamble organized?

The first section of this preamble contains background information regarding the origin of the proposed amendments. This section also discusses the EPA's legal authority under the Clean Air Act (CAA) to promulgate (including subsequent amendments to) the Greenhouse Gas 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 required by these amendments or for existing data elements for which a confidentiality determination has not previously been proposed. Section II of this preamble describes the types of amendments included in this proposed rulemaking and includes the rationale for each type of proposed change. Section III of this preamble is organized by part 98 subpart and contains detailed information on the proposed revisions to part 98 and the rationale for the proposed amendments in each section. Section IV of this preamble discusses additional requests for comments related to potentially expanding or adding new source categories and other potential future amendments to the GHG Reporting Rule. Section V of this preamble discusses when the proposed revisions to part 98 would apply to reporters. Section VI of this preamble discusses the proposed 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 a determination has not been previously established. Section VII of this preamble discusses the impacts of the proposed amendments. Section VIII of this preamble describes the statutory and executive order requirements applicable to this action.

B. Executive Summary

The EPA is proposing amendments to part 98 to implement improvements to the GHGRP. After more than 10 years of implementation of the program, the EPA has assessed the data collected, emissions, and trends established from annual reports in each industrial sector required to report. In this review, the EPA has evaluated the requirements of the GHGRP to identify areas of improvement, such as where the rule may be modified to reflect the EPA's current understanding of United States (U.S.) GHG emission trends, or to improve data collection and reporting where additional data may be necessary to better understand emissions from specific sectors or inform future policy decisions. The EPA has subsequently identified improvements to the calculation, monitoring, and reporting requirements that would incorporate new data or updated scientific knowledge; reflect new emissions sources; improve analysis and verification of collected data; provide additional data to complement or inform other EPA programs; or streamline calculation, monitoring, or reporting to provide flexibility or increase the efficiency of data collection.

The proposed amendments include improvements to requirements that would enhance the quality of the data collected, clarify elements of the rule, and streamlining changes. The types of proposed amendments that would improve the quality of the data collected under the rule include revisions to update 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; providing for collection of additional data to understand new source categories or new emission sources for specific sectors; additions or modifications to reporting requirements in order to eliminate data gaps and improve verification of emissions estimates; revisions that address prior commenter concerns or clarify requirements, and editorial corrections that would improve the public's understanding of the rule.

The types of streamlining changes that the EPA is proposing include revisions to applicability for certain industry sectors to account for changes in usage of certain GHGs or 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 includes a request for comment related to potentially expanding existing categories or including additional new source categories to the Greenhouse Gas Reporting Rule. In these cases, the EPA is seeking additional information to better inform our consideration of proposing these new source categories to the GHGRP. Therefore, the EPA is specifically requesting comment related to the potential expanded or new source categories described in this section. The EPA is also requesting comment on potential future amendments to add new calculation, monitoring, and reporting requirements for the aluminum production source category. If the Agency becomes comfortable that the information available is sufficient to support a rule revision, the EPA may consider undertaking a future action to revise or add source categories or to incorporate updated calculation and reporting requirements.

Further, this action includes a proposal to update 40 CFR part 9 in accordance with the publication requirements of the PRA to include the OMB control number issued under the PRA for the information collection request (ICR) for the GHGRP.

Finally, this action proposes to establish and/or revise confidentiality determinations for the reporting of certain data elements added or revised in these proposed amendments, and for certain existing data elements for which no confidentiality determination has been previously proposed, or for which we are proposing to amend a previously established confidentiality determination.

Most of the changes that are proposed are not anticipated to significantly increase the recordkeeping and reporting burden associated with the GHGRP. The proposed changes are anticipated to improve the quality of the data reported under the program. Some of the proposed revisions could potentially increase burden in cases where the proposed amendments add or revise reporting requirements. The estimated incremental costs include an average burden of $1,424,775 per year beginning in reporting year (RY) 2023.

The EPA anticipates that the proposed changes may take effect on January 1, 2023 and would apply beginning with reports submitted for RY2023, which are required to be submitted to the EPA by April 1, 2024.

C. Background on This Proposed Rule

The GHG Reporting Rule was published in the **Federal Register** (FR) on October 30, 2009 (74 FR 56260) (hereafter referred to as the 2009 Final Rule). The 2009 Final Rule became effective on December 29, 2009 and requires reporting of GHGs from various facilities and suppliers, consistent with the 2008 Consolidated Appropriations Act.[1] The EPA issued additional rules in 2010 finalizing the requirements for subpart T (Magnesium Production), subpart FF (Underground Coal Mines), subpart II (Industrial Wastewater Treatment), and subpart TT (Industrial Waste Landfills) (75 FR 39736, July 12, 2010); subpart W (Petroleum and Natural Gas Systems) (75 FR 74458, November 30, 2010); subpart I (Electronics Manufacturing), subpart L (Fluorinated Gas Production), subpart DD (Electrical Transmission and Distribution Equipment Use), subpart QQ (Importers and Exporters of Fluorinated GHGs Contained in Pre-Charged Equipment or Closed-Cell Foams), and subpart SS (Electrical Equipment Manufacture or Refurbishment) (75 FR 74774, December 1, 2010); and subpart RR (Geologic Sequestration of Carbon Dioxide) and subpart UU (Injection of Carbon Dioxide) (75 FR 75060, December 1, 2010). Following the promulgation of these subparts, the EPA finalized several technical and clarifying amendments to these and other subparts under the GHGRP (75 FR 79092, December 17, 2010; 76 FR 22825, April 25, 2011; 76 FR 36339, June 22, 2011; 76 FR 59533, September 27, 2011; 76 FR 59542, September 27, 2011; 76 FR 73866, November 29, 2011; 76 FR 80554, December 23, 2011; 77 FR 10373, February 22, 2012; 77 FR 48072, August 13, 2012; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 68162, November 13, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014; 79 FR 73750, December 11, 2014; 80 FR 64262, October 22, 2015; and 81 FR 86490, November 30, 2016). The amendments generally added or revised requirements in the existing subparts of part 98, including revisions that were intended to improve clarity and consistency across the calculation, monitoring, and data reporting requirements. The EPA finalized additional amendments (81 FR 89188, December 6, 2016) to streamline implementation of the rule, to improve the quality and consistency of the data collected under the rule, and to clarify or provide updates to certain provisions that have been the subject of questions from reporting entities. The EPA is proposing additional amendments and requesting comment in a continuation of the effort to improve the GHGRP.

D. Legal Authority

The EPA is proposing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 Final Rule (74 FR 56260), CAA section 114(a)(1) provides the EPA broad authority to require the information

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[1] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. See *https://www.congress.gov/110/plaws/publ161/PLAW-110publ161.pdf* (accessed September 7, 2021).

proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a wide variety of CAA provisions. See the preambles to the proposed GHG Reporting Rule (74 FR 16606, October 10, 2009) and the 2009 Final Rule for further information.

II. Overview and Rationale for Proposed Amendments to 40 CFR Part 98 and 40 CFR Part 9

Since 2010, the GHGRP has been a reliable and high-quality source of GHG data. The data collected under 40 CFR part 98 is used to inform the EPA's understanding of the relative emissions and distribution of emissions from specific industries, the factors that influence GHG emission rates, and to inform policy options and potential regulations. The data published under the GHGRP also serves to enable key stakeholders to understand, track, and compare greenhouse gas emissions and identify and take action on emission reduction opportunities. Further, the data collected under the GHGRP has also been used to inform other regulations, for example, proposed New Source Performance Standards (NSPS) and Emission Guidelines for the oil and gas industry and for municipal solid waste (MSW) landfills under 40 CFR part 60.

Throughout the life of the GHGRP, the EPA has made several improvements to the rule to address data gaps, reflect updates to scientific information, or to incorporate improvements to calculation, monitoring, or measurement methodologies. For example, in 2013, the EPA finalized technical amendments including changes to applicability, improvements to calculation methods, and updated reporting requirements, as well as amendments to incorporate new data from the Intergovernmental Panel on Climate Change (IPCC) on estimated global warming potentials (GWPs) (78 FR 71904, November 29, 2013). More recently, the EPA finalized edits to the petroleum and natural gas systems source category to address potential gaps in coverage, improve methods, and ensure high quality data reporting (81 FR 86490, November 30, 2016). The EPA last updated the GHGRP in 2016, when it implemented revisions to streamline and improve implementation of the rule and to improve the quality of the data collected, including expanding monitoring and reporting requirements that were necessary to improve verification and served to improve the accuracy of the data used to inform the Inventory of U.S. Greenhouse Gas Emissions and Sinks (hereafter referred to as the ''U.S. GHG Inventory'') (81 FR 89188, December 9, 2016).

The EPA has also continuously conducted outreach to stakeholders through various means, including responding to questions from reporters, engaging through compliance assistance webinars, soliciting feedback via a public testing process, interacting with reporters during the verification of submitted data, and soliciting comments during rulemakings. Thus, the EPA has subsequently identified, proposed, and finalized several technical and clarifying amendments to various subparts under the GHGRP to enhance the quality of the data reported, improve our understanding of GHG emission sources and trends, and improve implementation, particularly where we have identified changes to industry processes, emissions trends, types of emissions sources, or new data or scientific knowledge that would allow us to better understand the quantity and distribution of U.S. GHG emissions.

The EPA recently evaluated the requirements of the GHGRP to identify areas of improvement, such as where the rule may be modified to reflect the EPA's current understanding of U.S. GHG emission trends, or to improve data collection and reporting where additional data may be necessary to better understand emissions from specific sectors or inform future policy decisions. The proposed amendments include improvements to the calculation, monitoring, and reporting requirements that would incorporate updates to existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or new emission sources for specific sectors; improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates and improve verification of collected data; and provide additional data to complement or inform other EPA programs. We are also proposing revisions that clarify or update provisions that have been unclear. The proposed amendments include:

- Amendments to update emission factors to incorporate new measurement data that more accurately reflects 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;
- Revisions to specific sectors to expand reporting to include new source categories or new emission sources, in order to improve the accuracy and completeness of the data provided by the GHGRP;
- Adding or modifying reporting requirements to eliminate data gaps and improve verification of emissions estimates; and
- Revisions that address prior commenter concerns or provide additional information for reporters to better or more fully understand their compliance obligations, that clarify requirements that reporters have previously found vague to ensure that accurate data are being collected, and editorial corrections or harmonizing changes that would improve the public's understanding of the rule.

The EPA is also soliciting additional comment on potentially expanding existing subparts or adding other new subparts to collect data for several new source categories, as well as requesting comment on potential future amendments to add new calculation, monitoring, and reporting requirements for the aluminum production source category, as discussed in section IV of this preamble.

The EPA has also identified additional areas in the GHGRP where revisions to part 98 could be streamlined. Through this document, the EPA is proposing several amendments to revise specific provisions in part 98 that would streamline calculation, monitoring, or reporting to provide flexibility or increase the efficiency of data collection. The types of revisions we are proposing would 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 proposed revisions include:

- Revisions to applicability for certain industry sectors without the 25,000 metric tons carbon dioxide equivalent (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;
- Providing flexibility for and simplifying monitoring and calculation methods where further monitoring and data collection would 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 streamline 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 would not likely provide new insights or knowledge of the industry sector, emissions, or trends at this time.

Sections II.A and II.B of this preamble describe the above changes in more detail and provide rationale for the changes included in each category. Additional details for the specific amendments proposed for each subpart are included in section III of this preamble. We are seeking public comment only on the proposed revisions and issues specifically identified in this document for the identified subparts. We expect to deem any comments received addressing other aspects of 40 CFR part 98 to be outside of the scope of this proposed rulemaking.

Finally, we are also proposing 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 ICR for 40 CFR part 98. This amendment is described in section II.C of this preamble.

A. Revisions To Improve the Quality of Data Collected Under 40 CFR Part 98 and Other Minor Revisions or Clarifications

The data collected under part 98 are used to inform the EPA's understanding of the relative emissions and distribution of emissions from specific industries, the factors that influence GHG emission rates, and to inform policy options and potential regulations. Following several years of implementation and outreach, the EPA has identified certain areas of the rule where updates to emissions factors or other default factors; improvements to calculation methodologies; collection of additional data on GHG emissions, emissions sources, or end uses; additions or revisions to data elements or other reporting requirements; and other technical amendments, clarifications, and corrections would enhance the quality and accuracy of the data collected under the GHGRP. These proposed changes include consideration of comments raised by stakeholders in prior rulemakings that would more closely align rule requirements with the processes conducted at specific facilities, consideration of data gaps identified in collected data where additional data would improve verification of data reported to the GHGRP, and consideration of additional data needed to help better understand changing industry emission trends. Overall, these proposed changes would provide a more comprehensive, nationwide GHG emissions profile reflective of the origin and distribution of GHG emissions in the United States and would more accurately inform EPA policy options for potential regulatory or non-regulatory CAA programs. The EPA additionally uses the data from the GHGRP, which would include data from these proposed changes, to improve estimates used in the U.S. GHG Inventory.

In some cases, we are proposing to redefine certain industry sectors to include additional GHGs not previously reported, or to add emissions estimations methodologies and include reporting of GHGs from newly identified sources of emissions in certain industry sectors, to better account for changes in industry emission trends. The proposed amendments reflect adjustments to the rule where we have identified changes in the type and scope of GHGs emitted or supplied, such as certain sectors that have implemented alternative equipment technology, switched to use of GHGs with a lower GWP, or that have implemented new end uses for GHGs that are emitted or supplied. In other cases, we have identified gaps in the current coverage of the GHGRP that leave out potentially significant emission sources, for example, large, atypical release events at oil and gas facilities such as wellhead leaks. The proposed amendments would also add a new source category that would provide additional data on amounts of CO_2 that are geologically sequestered in association with enhanced oil recovery (EOR) operations. Many of the revisions proposed in this action would better capture the changing landscape of greenhouse gas emissions and provide for more complete coverage of U.S. GHG emission sources. Such changes are necessary for the EPA to continue to analyze the relative emissions and distribution of emissions from specific industries and to improve the overall quality of the data collected under the GHGRP. These changes would also complement other EPA regulations, such as NSPS and emission guidelines (EG) for the oil and gas industry and would also be used to inform and improve future policy decisions.

The specific changes that we are proposing, as described in this section, are described in detail for each subpart in sections III.A through III.W of this preamble.

1. Updates to Emission Factors To Improve Accuracy of Reported Data

In order to improve the accuracy of the data collected under the GHGRP, we are proposing to revise emission factors where we have received improved measurement data or feedback from stakeholders. Some of the calculation methodologies provided in the GHGRP rely on the use of emission factors, and the use of emissions or default factors decreases the need for additional monitoring or measurements from individual facilities. The proposed rule includes revisions to emission factors in a number of source categories, where we have received or identified updated measurement data. For example, we are proposing several updates to the emission factors and default destruction and removal efficiency values in subpart I (Electronics Manufacturing). The proposed emission factors are based on review of newly submitted data from the 2017 and 2020 technology assessment reports submitted 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*").[2] We are also proposing updates to the emission factor calculation methods that are used to calculate utilization and by-product emission rates submitted in the technology assessment report under subpart I, in order to ensure that emission factors are developed in a consistent manner across facilities and over time and to allow the EPA to compare emission factors across the industry and track trends in industry emission rates.

In some cases, the proposed emission factors would improve reported data by better reflecting recent industry trends. For example, based on input from stakeholders, we are proposing updated emission factors for the modeling of methane (CH_4) generation from waste disposed at landfills in subpart HH (Municipal Waste Landfills). The updated emission factors reflect an industry trend of increased disposal of inert materials that do not contribute to CH_4 generation. The EPA received data from stakeholders in the waste industry following comments received during the expert and public review period for the U.S. GHG Inventory, which uses directly reported emissions values from subpart HH to estimate national CH_4 emissions from MSW landfills

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[2] Intergovernmental Panel on Climate Change (IPCC). *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.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

throughout the entire United States. The proposed change will update default factors and will result in more accurate estimates of landfill emissions and pose no additional reporting burden.

We are also proposing to update the default biogenic fraction for tire combustion in subpart C (General Stationary Fuel Combustion) and the emission factors for natural gas pneumatic devices and for equipment leaks from natural gas distribution sources (including pipeline mains and services, below grade transmission-distribution transfer stations, and below grade metering-regulating stations) and equipment at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities in subpart W (Petroleum and Natural Gas Systems). The proposed emission factors are more representative of GHG emissions sources and would improve the overall accuracy of the data collected under the GHGRP and would ultimately benefit stakeholders who rely on GHGRP data to understand the sources and magnitude of GHGs from specific facilities, as well as improve the quality of data used to inform future policy or regulation.

2. Improvements To Existing Emissions Estimation Methodologies

We are proposing several revisions to modify calculation equations to incorporate refinements to methodologies based on an improved understanding of emission sources. In some cases, we have become aware of discrepancies between assumptions in the current emission estimation methods and the processes or activities conducted at specific facilities, where the proposed revisions would reduce reporter errors. In other cases, we are proposing to revise the emissions estimation methodologies to incorporate recent studies on GHG emissions or formation that reflect updates to scientific understanding of GHG emissions sources. The proposed changes will improve the quality and accuracy of the data collected under the GHGRP, increase our understanding of the relative distribution of GHGs that are emitted, and better reflect GHG end uses or where GHGs are bound in products.

For example, for subpart I, we are proposing several edits to the stack testing methodology, including adding new equations and a table of default weighting factors to calculate the fraction of fluorinated input gases and by-products exhausted from tools with abatement systems; revising equations that calculate the weighted average DREs for individual fluorinated greenhouse gases (F–GHGs) across process types; requiring that all stacks 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 other subparts, including subparts G (Ammonia Manufacturing), P (Hydrogen Production), and S (Lime Manufacturing), we are proposing revisions to the calculation methodology to allow for subtraction of carbon dioxide (CO_2) that is captured and bound in other products (*e.g.,* urea or methanol) from calculated and reported emissions. The proposed changes, by removing the CO_2 that is not directly emitted from these facilities from the calculation methodology, would provide a more accurate estimate of the direct sector emissions and would provide consistency in our approach across the GHGRP.

For subpart Y (Petroleum Refineries), we are proposing to amend the calculation methodology for delayed coking units (DCUs), which uses a steam generation model to estimate emissions. The proposed changes are targeted to address issues identified during verification of reported data, where we have noticed that the activities conducted at certain facilities do not comport with some of the underlying assumptions of the steam generation model. The proposed changes will modify the current equation to more accurately estimate emissions and to be more universally applicable to these facilities.

Additional details of these types of proposed changes are discussed in section III of this preamble.

3. Revisions To Address Potential Gaps in Reporting of Emissions Data for Specific Sectors

We are proposing several amendments to include reporting of additional emissions or emissions sources for specific sectors to address potential gaps in reporting. We are also proposing to improve the existing rule requirements by proposing new or revised calculation, monitoring, or reporting requirements that would help us to better understand and track emissions in specific sectors; establish requirements for a new source category for quantifying geologic sequestration of CO_2 in association with EOR operations; and identify end uses of GHGs that are not currently accounted for in existing reporting, for consideration in future policy development. Such data would continue to inform, and are relevant to, the EPA's carrying out a wide variety of CAA provisions. For example, identifying new emissions or new emission sources from direct emitters could inform decisions about whether and how to use section 111 of the CAA to establish NSPS for various source categories emitting GHGs. The data may also inform the EPA's implementation of section 103(g) of the CAA regarding improvements in nonregulatory strategies and technologies for preventing or reducing air pollutants. The data published under the GHGRP serves to enable the Agency and stakeholders to understand, track, and compare greenhouse gas emissions and identify emission reduction opportunities. Over the last 10 years, the collection of these data 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 amendments we are proposing are intended to address data gaps that have been identified in the implementation of the program or from review of improved scientific assessments and would allow the EPA to better characterize U.S. GHG emissions. The improved data would subsequently better inform other agency policies and programs under the CAA.

For example, we are proposing several revisions to subparts DD (Electrical Transmission and Distribution Equipment Use) and SS (Electrical Equipment Manufacture or Refurbishment) to improve the quality of the data collected from these industrial sectors. Currently, these subparts include ''all electric transmission and distribution equipment and servicing inventory'' used within an electric power system, and related manufacturing and refurbishing processes, that use or include sulfur hexafluoride (SF_6) and perfluorocarbons (PFCs). When the final rule establishing subpart DD was published in 2010 (75 FR 74774, December 1, 2010, hereinafter referred to as the 2010 Final Rule for Additional Sources of Fluorinated GHGs), SF_6 was the most commonly used insulating gas in the electrical power industry, and PFCs were occasionally used as dielectrics and heat transfer fluids in power transformers. During the implementation of the reporting program, electrical power systems equipment manufacturers and fluorinated greenhouse gas suppliers have introduced alternative technologies and replacements for SF_6 with lower GWPs, including fluorinated gas mixtures. We are proposing to revise the existing calculation, monitoring, and reporting requirements of these subparts to require reporting of additional F–GHGs, in order to better track emissions from equipment using alternative gases that are not currently accounted for.

Additionally, we have become aware of potentially significant sources of emissions in specific industry sectors for which there are no current emission estimation methods within part 98. For example, under subpart I, we are proposing a calculation methodology to estimate emissions of perfluoromethane (CF_4) from hydrocarbon-based emissions control systems. The proposed changes reflect recent studies that have shown that direct reaction between molecular fluorine (F_2) and hydrocarbons to form CF_4 can occur in hydrocarbon-fueled combustion emissions control systems, and we are proposing to incorporate calculations from the *2019 Refinement* to account for the formation and emission of CF_4 from this potentially significant emissions source.

For subpart W, we are proposing to add calculation methodologies and requirements to report GHG emissions for several additional sources. We are proposing to add a new emissions source, referred to as ''other large release events,'' to capture abnormal emission events that are not accurately accounted for using existing methods in subpart W. This additional source would cover events such as storage wellhead leaks, well blowouts, and other large, atypical release events and would apply to all types of facilities subject to subpart W. Reporters would calculate GHG emissions using measurement data or engineering estimates of the amount of gas released and measurement data, if available, or process knowledge (best available data) to estimate the composition of the released gas. We are also proposing to require reporting of existing emission sources by additional industry segments. For example, we are proposing to require liquified natural gas (LNG) import/export facilities to begin calculating and reporting emissions from acid gas removal vents.

In other cases, we are proposing changes to improve our understanding of end-uses of GHGs and to better understand GHG supply. For subpart OO (Suppliers of Industrial Greenhouse Gases), we are proposing to require suppliers of nitrous oxide (N_2O), saturated PFCs, and SF_6 to identify the end uses for which the N_2O, SF_6, or PFC is used, and the quantities of N_2O, SF_6, or each PFC transferred to each end use, if known. This requirement would help to inform the development of GHG policies and programs by providing information on N_2O, SF_6, and PFC uses and their relative importance, where the GWP-weighted quantities of these compounds that are supplied annually to the U.S. economy are relatively large, and where the identities and magnitudes of the uses of these compounds are less well understood.

The EPA is also proposing revisions to incorporate a new source category to add calculation and reporting requirements for quantifying geologic sequestration of CO_2 in association with EOR operations. The proposed requirements would be included under a new subpart VV and would apply to reporters that choose to use the International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage*[3] *Using Enhanced Oil Recovery (CO_2-EOR)* (hereafter referred to as ''CSA/ANSI ISO 27916:2019'') as a means of quantifying geologic sequestration. Under existing GHGRP requirements, facilities that sequester CO_2 through EOR operations may opt into subpart RR. Proposed new subpart VV provides an alternative method of reporting geologic sequestration in association with CO_2-EOR presenting another option for reporters who are sequestering CO_2 through their EOR operations but do not choose to report under subpart RR. We are proposing to add this new source category because collecting additional information from these sources would improve our knowledge on the amounts of CO_2 that are geologically sequestered in association with EOR operations and allow the Agency to more comprehensively track and document the flow of CO_2 through the economy to better inform EPA policy and programs under the CAA related to the use of CO_2 capture and geologic sequestration. Thus, the rationale for proposing subpart VV is analogous to the rationale for originally proposing and finalizing subpart RR, that is to enable the EPA to monitor the growth and efficacy of geologic sequestration as a greenhouse gas mitigation technology over time, to evaluate relevant policy options, and to reconcile information obtained with data obtained from 40 CFR part 98, subpart PP on CO_2 supplied to the economy. The proposed requirements are discussed in section III.W of this preamble.

The proposed changes would improve the overall quality and completeness of the data collected by the GHGRP, and would be useful for informing future policy decisions, such as opportunities to reduce emissions. The EPA is also soliciting additional comment on potential collection of data under other new source categories, as discussed in section IV of this preamble.

4. Revisions to Reporting Requirements To Improve Verification and the Accuracy of the Data Collected

The EPA is proposing several revisions to existing reporting requirements to improve the quality of the data that are currently reported, or to collect more useful data that would improve verification of reported data. Such revisions would better characterize U.S. GHG emissions and trends and would better enable the EPA to obtain data that is of sufficient quality that it can be used to support a range of future climate change policies and regulations, including but not limited to information relevant to carrying out provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs.

For example, we are proposing revisions to the reporting of unit level information under subpart C. Currently, individual unit information (*i.e.,* the unit type and the maximum rated heat input capacity) is only required to be reported for specific individual unit reporting configurations. The individual unit information allows the EPA to aggregate emissions according to unit type and size and provides a better understanding of the emissions from specific unit types. To improve verification and analysis of reported data, the EPA is proposing to require reporting of certain unit level information for each unit in an aggregation of units or common pipe configuration, excluding units less than 10 million British thermal units per hour (mmBtu/hr).

Under subpart H (Cement Production) and subpart S, we are proposing to collect additional data elements where the EPA has little data on which to build verification checks. For these subparts, we are proposing to collect annual averages of chemical composition input data on a facility-basis. The proposed data elements would assist the EPA in verification of continuous emission monitoring systems (CEMS) facility emissions.

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[3] The terms ''geologic sequestration'' and ''geologic storage'' are used synonymously for purposes of this subpart.

Because CEMS facilities typically include combustion and process emissions that are vented through the same stack, process and combustion emissions are usually mixed and indifferentiable. By collecting average chemical composition data, the EPA would be able to compare and differentiate process emissions from CEMS facilities. Such additions to reporting would improve the accuracy of the emissions data and render such information more valuable and useful.

For subpart W, we are proposing to add or revise reporting requirements to better understand and characterize the emissions for several emission sources. For example, we are proposing to collect additional information from facilities with liquids unloadings to differentiate between manual and automated unloadings.

Additionally, under subpart GG (Zinc Production), the EPA is proposing that facilities report the total amount of electric arc furnace (EAF) dust annually consumed by all Waelz kilns at the facility. In this case, because the amount of EAF dust consumed in Waelz kilns is strongly correlated with CO_2 emissions, the proposed data element would serve as a useful data validation point and could potentially be used for the future development of an emission factor.

The proposed revisions to add new reporting requirements would also extend the usefulness of GHGRP data to improve the EPA's ability to carry out other CAA programs. For example, we are proposing under subpart HH to require MSW landfills to report data on the landfill CH_4 emissions that are destroyed versus sent to landfill gas energy projects. This information would additionally help inform the development of GHG policies and programs by providing information on the amount of recovered CH_4 that is beneficially used in energy recovery projects and would inform the EPA, as well as state and local government officials, on progress towards renewable energy targets, and would also be useful to other stakeholders. As discussed in prior amendments, the GHGRP is also intended to supplement and complement the U.S. GHG Inventory and other EPA programs by advancing the understanding of emission processes and monitoring methodologies for particular source categories or sectors. The GHGRP also provides data from individual facilities and suppliers above certain thresholds, which can additionally be used to improve the assumptions and emissions values used in the U.S. GHG Inventory (see 81 FR 2546, January 15, 2016). The facility, unit, and process level GHG emissions data for industrial sources collected under the GHGRP does not replace the system in place to produce the top-down U.S. GHG Inventory, but can be additionally used to improve the accuracy of the U.S. GHG Inventory by confirming the national statistics and emission estimation methodologies. Therefore, the EPA periodically reviews the data from the GHGRP to consider whether there are data that are useful to the GHGRP and that would also improve the accuracy of the data included in the U.S. GHG Inventory or improve our ability to inform the development of GHG policies and programs. We are proposing several amendments that would improve the data collected by the GHGRP, and subsequently, would provide data that would benefit and support the U.S. GHG Inventory. For example, we are proposing to revise the current requirements for subpart N (Glass Production) facilities to require reporting the annual quantities of glass produced by glass type. In general, the emissions profile of a specific glass type is relatively consistent with the composition of the glass, based on the major raw materials (limestone, dolomite, and soda ash). Collecting data on annual production by glass type would improve verification for the GHGRP by allowing the EPA to compare emissions by glass types produced and would also provide useful information to improve analysis of this sector in the U.S. GHG Inventory.

5. Technical Amendments, Clarifications, and Corrections

We are proposing other technical amendments, corrections, and clarifications that would improve understanding of the rule. These revisions primarily include revisions of requirements to better reflect the EPA's intent or editorial changes. Some of these proposed changes result from consideration of questions raised by reporters through the GHGRP Help Desk or electronic Greenhouse Gas Reporting Tool (e-GGRT) and are intended to resolve uncertainties in the regulatory text. For example, we are proposing amendments in several subparts that would clarify requirements that have led to reporter uncertainty, such as reported data elements that may be unclear and misread by reporters. In several cases, these provisions may have introduced uncertainty into the rule and resulted in reporting that is inconsistent with the rule requirements. The proposed clarifications would reduce the uncertainty associated with certain reported data elements and increase the likelihood that reporters will submit accurate reports the first time. For example, we are proposing a revision to subpart Y to resolve the potential discrepancy between the flare emission calculations at 40 CFR 98.253(b), which requires that all gas discharged through the flare stack must be included in the calculations except for pilot gas, and the requirements at 40 CFR 98.253(b)(1)(iii), which excludes startup, shutdown, and malfunction (SSM) events less than 500,000 standard cubic feet per day (scf/day) from equation Y–3. As another example, under subpart W, the EPA is proposing to clarify the calculation of emissions from open thief hatches on atmospheric storage tanks that use vapor recovery systems and flares, by revising 40 CFR 98.233(j)(4) and (5) to specify how to account for those emissions. The EPA's intent is that reporters should be including emissions from open thief hatches, but the current rule does not provide explicit provisions for them. We are also proposing to revise 40 CFR 98.236(j)(1) to clarify reporting of emissions from atmospheric storage tanks with vapor recovery systems and flares. These proposed clarifications and corrections would also reduce the burden associated with reporting, data verification, and EPA review. Additional details of these types of proposed changes are discussed in section III of this preamble.

Other minor changes being proposed include correction edits to fix typos, minor clarifications such as adding a missing word, harmonizing changes to match other proposed revisions, reordering of paragraphs so that a larger number of paragraphs need not be renumbered, and others as reflected in the draft proposed redline regulatory text in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

B. Revisions To Streamline and Improve Implementation of 40 CFR Part 98

Since 2010, the EPA has collected data through the GHGRP to assess industry emissions, and has, through review of annually submitted data, gained substantial knowledge of the types, quantities, and distribution of emissions across industry sectors. Through this process, the EPA has engaged in stakeholder outreach, solicited feedback, responded to questions from reporters, and identified site specific scenarios or issues that could impact the quality of the data reported. In a recent review of the requirements of the program, we have identified several areas of part 98 that could be revised or simplified to reduce technical challenges associated with implementation or improve the efficiency of the requirements, while maintaining the quality of the data collected. We are subsequently proposing several revisions that would streamline the calculation, monitoring, and reporting burden associated with the rule. These revisions would revise applicability estimation methodologies, provide flexibility for or simplifying calculation and monitoring methodologies, streamline recordkeeping and reporting, and other minor technical corrections or clarifications.

The specific changes that we are proposing that are intended to streamline part 98, as described in this section, are described in detail for each subpart in sections III.A through III.W of this preamble.

1. Revisions To Applicability for Certain Industry Sectors

We are proposing to change the applicability criteria for three subparts to account for changes in usage of certain GHGs, or where the current applicability estimation methodology may overestimate emissions. The proposed changes would improve the estimation methodologies used to determine applicability for specific subparts and more accurately focus GHGRP and reporter resources on coverage of large industrial emitters within these sectors; such changes are in keeping with our goal to maximize coverage and collection of GHG emissions data from each sector while excluding small emitters.

Currently, any facility that contains a source category listed in Table A–3 of subpart A of part 98 (General Provisions) is subject to reporting under part 98 (referred to as ‘‘all-in’’ source categories because reporting applies regardless of other source category or stationary fuel combustion emissions at the facility). Table A–3 defines a few of the ‘‘all-in’’ source categories using thresholds that use metrics other than $mtCO_2e$ of emissions. A facility that contains a source category listed in Table A–4 of subpart A of part 98 must report only if estimated annual emissions from all applicable source categories in Tables A–3 and Table A–4 of part 98 are 25,000 $mtCO_2e$ or more (referred to as ‘‘threshold’’ source categories). The EPA has used the ‘‘threshold’’ approach where a source category contains emitters with a range in emissions quantity and the EPA wants to capture those facilities within the source category with larger total emissions from multiple process units or collocated source categories that emit significant levels of GHGs collectively, and not burden smaller emitters with a reporting obligation. The EPA has used the ‘‘all-in’’ approach for industries for which all facilities are emitters of a similar quantity or to gather data on certain industries to identify the parameters that influence GHG emissions from the source category.

The EPA used alternative metrics for some subparts in Table A–3 for a variety of reasons. In some cases, the metric provides a more straightforward way for facilities within that source category to evaluate their applicability. For example, for subpart DD (Electrical Transmission and Distribution Equipment), the metric is based on the total nameplate capacity of SF_6 and PFC-containing equipment and was approximated as equivalent to the 25,000 metric tons of CO_2 threshold. To ensure that the GHGRP data collected better reflects the current electrical power system industry, we are proposing to remove the existing nameplate capacity threshold, and instead provide a calculation method for facilities to estimate total annual GHG emissions for comparison to the 25,000 metric tons of CO_2 threshold. These changes align with proposed changes to redefine the source category to include equipment containing ‘‘fluorinated GHGs (F–GHGs), including but not limited to sulfur-hexafluoride (SF_6) or and perfluorocarbons (PFCs)’’, and reflect that some facilities within the industry sector have begun to use lower GWP F–GHGs, which is not reflected when using only the nameplate capacity of the equipment to determine applicability. The proposed changes would establish an updated comparison to the threshold and would account for additional fluorinated gases (including F–GHG mixtures) used in industry. The proposed changes to the threshold would decrease the number of facilities with annual emissions less than 25,000 metric tons CO_2e that would be required to report. The proposed changes would require tracking of additional fluorinated gases and the equipment they are contained in; however, this additional burden is expected to be small as these gases are not yet widely used.

Similarly, we are proposing to revise the threshold for subpart SS (Electrical Equipment Manufacture or Refurbishment), which is based on total annual purchases of SF_6 and PFCs. As with subpart DD, we are proposing to revise the existing requirements of subpart SS to require reporting of additional F–GHGs beyond SF_6 and PFCs, and we are proposing to revise the subpart SS threshold to align with these changes. The proposed changes would continue to be based on the total annual purchases of F–GHGs but would establish a calculation method for comparison to the 25,000 metric tons of CO_2 threshold, and would better account for the additional fluorinated gases (including F–GHG mixtures) reported by industry. The proposed changes would require tracking of additional fluorinated gases and the equipment they are contained in; however, this additional burden is expected to be small as these gases are not yet widely used.

We are also proposing revisions to provide a second option for an alternative calculation methodology, that is consumption-based, that reporters subject to subpart I (Electronics Manufacturing) could use to determine whether they meet the emissions threshold for reporting applicability. For subpart I (Electronics Manufacturing), the current provisions of 40 CFR 98.91 require facilities to estimate whether the 25,000 metric tons of CO_2e threshold is met based on emissions estimates assuming the facility operates at its annual manufacturing capacity, which may result in significant over-estimation of emissions. The capacity-based methodology has required reporting by some electronics manufacturing facilities that use smaller amounts of F–GHGs. For subpart I, the method for determining the applicability was chosen to reduce the burden on low-emitting facilities by providing a simplified method to estimate emissions for the purpose of assessing applicability. However, for subpart I, the applicability threshold provisions may currently require certain lower-emitting facilities to report where the capacity-based estimation methodology overestimates emissions. We are proposing to revise the applicability estimation methodology in subpart I to provide a second option for an alternative calculation method using a gas-consumption basis, and to use updated emission factors, so that facilities may choose instead to use a separate method that more accurately calculates potential facility emissions. This may result in fewer facilities reporting under subpart I, but these facilities are expected to have annual emissions that are lower than 25,000 metric tons of CO_2e. The gas consumption-based approach to determining applicability would require tracking gas consumption, which is not required by the production capacity-based threshold when determining applicability; however, this option to determine applicability is less burdensome than reporting to subpart I, which a facility would be required to do under the current rule if their capacity were above the capacity-based threshold. Under the current rule, facilities reporting under subpart I must collect gas consumption data to complete their subpart I report. Thus, overall, the burden for potential new entrants to the program would decrease.

We are proposing to revise the applicability of these subparts to more accurately estimate facility emissions and to more accurately focus GHGRP and reporter resources on the collection of data for the larger industrial emitters within these sectors. These changes would continue to maximize coverage of GHG emissions data from the sector while excluding small emitters. The proposed revisions would also adjust the applicability provisions for each of these subparts for consistency across part 98. The proposed changes to subparts I, DD, and SS are described in sections III.E, III.N, and III.U of this preamble.

2. Revisions To Streamline Monitoring and Calculation Methodologies

We are proposing revisions to provide flexibility for or simplify some calculation methods or monitoring requirements. We are proposing options to revise monitoring requirements in instances where we currently allow a less burdensome methodology for similar emissions sources; or where continuing to collect the data on the same frequency would be unlikely to provide significantly different values.

In some cases, we are proposing amendments that would add flexibility to the calculation methods to add less burdensome options that would correspond with a decrease in actual data collection. These types of proposed changes would simplify monitoring for reporters without impacting the quality of the data reported. For example, for subpart Y (Petroleum Refineries), we are proposing to allow the use of mass spectrometer analyzers to determine gas composition and molecular weight without the use of a gas chromatograph. The proposed revisions would allow reporters to use the same analyzers used for process control or for compliance with continuous sampling required under the National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries (40 CFR part 63, subpart CC) to comply with the GHGRP requirements in subpart Y. Currently, these reporters must conduct separate periodic sampling of these gas streams for analysis using gas chromatography to comply with GHGRP requirements in subpart Y, and the proposed revisions would provide flexibility for and reduce burden for these reporters.

We are also proposing to clarify applicability provisions to reduce uncertainty regarding which calculation method should be used. For example, for subpart W (Petroleum and Natural Gas Systems), we are proposing to revise the definition of the Onshore Natural Gas Processing industry segment so that reporters have more certainty regarding the industry segment and calculation methods that are applicable from the beginning of the year. The current definition of the Onshore Natural Gas Processing industry segment includes processing plants that fractionate gas liquids and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 million standard cubic feet (MMscf) per day or greater. Processing plants that do not fractionate gas liquids and have an annual average throughput of less than 25 MMscf per day may be part of a facility in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. Processing plants that do not fractionate gas liquids and generally operate close to the 25 MMscf per day threshold do not know until the end of the year whether they will be above or below the threshold, so they must be prepared to report under whichever industry segment is ultimately applicable. The two potentially applicable segments report emissions from different sources and with different calculation methods. For example, facilities in the Onshore Natural Gas Processing industry segment are not required to report emissions from atmospheric storage tanks and are required to measure leaks from individual compressors, while facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are required to report emissions from atmospheric storage tanks but may use emission factors to calculate emissions from compressors rather than conducting measurements. Therefore, we are proposing to revise the Onshore Natural Gas Processing industry segment definition in 40 CFR 98.230(a)(3) to remove the 25 MMscf per day threshold and more closely align subpart W with the definitions of natural gas processing in other rules (*e.g.,* 40 CFR part 60, subpart OOOOa). This proposed revision to the Onshore Natural Gas Processing industry segment definition would make it clear to reporters whether a processing plant would be classified as an Onshore Natural Gas Processing facility or as part of an Onshore Petroleum and Natural Gas Gathering and Boosting facility, and the applicable segment would not have the potential to change from one year to the next simply based on the facility throughput. As discussed in greater detail in section III.J.2.h of this preamble, we are also proposing several other changes to the Onshore Natural Gas Processing industry segment definition. Collectively, these proposed amendments are not expected to significantly affect the overall coverage of the GHGRP for the petroleum and natural gas systems industry, although we anticipate that some facilities would report under a different industry segment going forward.

Additional details of these types of proposed changes may be found in section III of this preamble.

3. Revisions To Streamline or Revise Recordkeeping and Reporting Requirements

Other proposed revisions to the rule include changes that would streamline the rule, such as revising certain reporting and recordkeeping requirements that are redundant or no longer being used, or that would remove duplicative reporting across EPA programs. For example, for subpart C (General Stationary Fuel Combustion Sources), we are proposing to amend certain provisions in 40 CFR 98.36 that require facilities with the aggregation of units or common pipe configuration types to report the total annual CO_2 mass emissions from the combustion of all fossil fuels combined. In this case, the reported configuration-level annual CO_2 emissions from all fossil fuels does not factor into any subpart- or facility-level total CO_2 emission calculations and is not integrated into e-GGRT's programmed ''roll up'' of emissions. Because we can adequately verify reports and interpret and analyze the reported data without these data elements, they are currently redundant and would not likely provide new insights or knowledge of the industry sector, emissions, or trends at this time.

In some cases, we are proposing to correct inconsistencies in the current rule. Under subpart Y, we are proposing a change to correct an inconsistency introduced by the amendments to the DCU calculations published on December 9, 2016 (81 FR 89188). Although the prior amendments removed the option to calculate CH_4 emissions from DCUs using the process vent method, the associated recordkeeping requirements for the process vent method were inadvertently not removed from the rule. Therefore, we are therefore proposing to remove the associated recordkeeping requirements.

For subpart W, we are proposing to revise reporting requirements related to atmospheric pressure fixed roof storage tanks receiving hydrocarbon liquids that follow the methodology specified in 40 CFR 98.233(j)(3) and equation W–15. The calculation methodology uses population emission factors and the count of applicable separators, wells, or non-separator equipment to determine the annual total volumetric GHG emissions at standard conditions. The associated reporting requirements in 40 CFR 98.236(j)(2)(i)(E) through (F) require reporters to delineate the counts used in equation W–15. Based on feedback from reporters, the EPA has determined that the reporting requirements are inconsistent with the language used in the calculation methodology and are not inclusive of all equipment to be included. Therefore, we are proposing to revise the reporting requirements to better align the requirement with the calculation methodology and streamline the requirements for all facilities reporting atmospheric storage tanks emissions using the methodology in 40 CFR 98.233(j)(3).

In some cases, we are streamlining reporting by removing duplicative reporting elements within or across GHGRP subparts. For example, we are proposing to eliminate duplicative reporting between subpart NN (Suppliers of Natural Gas and Natural Gas Liquids) and subpart W where both subparts require similar data elements to be reported to e-GGRT. For instance, for fractionators of natural gas liquids (NGLs), both subpart W (under the Onshore Natural Gas Processing segment) and subpart NN require reporting of the volume of natural gas received and the volume of NGLs received. The proposed amendments would limit the reporting of these data elements to facilities that do not report under subpart NN, thus removing the duplicative requirements from subpart W for facilities that report to both subparts. This will streamline reporting and reduce the burden on reporters.

We are also proposing to reduce the frequency of reporting information that we anticipate will not change on a frequent basis, such as the data collected for technology assessment reports under subpart I (Electronics Manufacturing). Based on the data collected in the initial technology assessment reports (currently required by 40 CFR 98.96(y)), we do not anticipate significant variations in these data elements within a three-year period going forward, as discussed in section III.E.2 of this preamble. Further, we are proposing several significant improvements to the technology assessment reports that will improve the usefulness and quality of the data provided in the reports. The proposed improvements would allow the EPA to collect these data less frequently while continuing to provide the EPA with updates to the gases and technologies used in semiconductor manufacturing.

Additional details of these types of proposed changes may be found in section III of this preamble.

C. Revisions to 40 CFR Part 9

The EPA is proposing a related change to update 40 CFR part 9 to include the OMB control number issued under the PRA for the ICR for the GHGRP. The OMB control numbers for EPA regulations in Title 40 of the CFR (after appearing in the **Federal Register**) are listed in 40 CFR part 9 and are included on the related collection instrument or form, if applicable. The EPA is proposing to amend the table in 40 CFR part 9 to list the OMB approval number under which the ICR for activities in the existing part 98 regulations that were previously approved by OMB have been consolidated. The prior approvals are included in OMB No. 2060–0629; OMB No. 2060–0629 has not previously been added to 40 CFR part 9 due to an oversight. This listing of the OMB control number and the subsequent codification in the CFR would correct this oversight and satisfy the display requirements of the PRA and OMB's implementing regulations at 5 CFR part 1320.

III. Proposed Amendments to 40 CFR Part 98

This section summarizes the specific substantive amendments proposed for each subpart, as generally described in section II of this preamble. The impacts of the proposed revisions are summarized in section VII of this preamble. A full discussion of the cost impacts for the proposed revisions may be found in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

A. Subpart A—General Provisions

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

In this action, we are proposing several clarifying revisions to subpart A of part 98 (General Provisions). For the reasons described in section II.A.5 of this preamble, we are proposing to clarify in 40 CFR 98.2(i)(1) and (2) that the provision to allow cessation of reporting or ''off-ramping,'' due to meeting either the 15,000 mtCO$_2$e level or the 25,000 mtCO$_2$e level for the number of years specified in 40 CFR 98.2(i), is based on the CO$_2$e 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 proposed changes clarify that reporters must rely on the emissions estimation methodologies used to report emissions and their annual emissions report totals to determine their ability to off-ramp. We are also proposing to clarify the off-ramp provisions at 40 CFR 98.2(i)(1) and (2) to specify that after an owner or operator off-ramps, the owner or operator must use equation A–1 and follow the requirements of 40 CFR 98.2(b)(4) 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. The requirements of 40 CFR 98.2(b) are different from the requirements of 40 CFR 98.3(c) in that the applicability determination requires more flexible calculation methods (*e.g.,* facilities may use any subpart C tier to estimate combustion emissions on 40 CFR 98.2(b), whereas they must follow the applicable subpart C tier to calculate combustion emissions under 40 CFR 98.3(c)). The proposed revisions make clear that reporters who have previously off-ramped would continue to follow the emission estimation methods used for determination of applicability to determine if they must resume reporting.

We are also proposing to revise 40 CFR 98.2(f)(1) to clarify how to calculate GHG quantities for comparison to the 25,000 mtCO$_2$e threshold for importers and exporters of industrial greenhouse gases; the proposed changes specify that the calculation must include the fluorinated heat transfer fluids (F–HTFs) that are imported or exported during the year. In the December 9, 2016 final rule, *2015 Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule* (81 FR 89234), the EPA expanded the definition of the source category for importers and exporters of industrial greenhouse gases to include facilities that destroy 25,000 mtCO$_2$e or more of industrial F–GHGs or F–HTFs annually, and entities that produce, import, or export F–HTFs that are not also F–GHGs. It was our intent that suppliers of F–HTFs be subject to the same thresholds.[4] However, we inadvertently neglected to update 40 CFR 98.2(f) to include F–HTFs in the calculation requirements. Similarly, we are proposing to add a new paragraph (k) to 40 CFR 98.2, specifying 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. This paragraph was inadvertently omitted when the rule was revised to cover stand-alone destruction facilities in 2016. The proposed changes would clarify that imported, exported, and destroyed F–HTFs and F–GHGs must be calculated and included when determining applicability.

We are also proposing new paragraph 40 CFR 98.4(n) that would apply in lieu of 40 CFR 98.4(h) for changes in the owner or operator of a facility in the four industry segments in subpart W (Petroleum and Natural Gas Systems) that have unique definitions of facility: Onshore Petroleum and Natural Gas Production; Onshore Petroleum and Natural Gas Gathering and Boosting; Natural Gas Distribution; and Onshore Natural Gas Transmission Pipeline. For these industry segments, particularly Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting, asset transactions between owners and operators can involve only some emission sources at the facility rather than the entire facility. In those cases, reporters have submitted numerous questions to the e-GGRT Help Desk requesting guidance regarding which owner or operator should report for the year in which the transaction occurred as well as which owner or operator is responsible for submitting revisions and responding to questions from the EPA regarding previous annual GHG reports. To address some of these questions, the EPA previously developed Frequently Asked Questions (FAQ) Q749.[5] However, neither the FAQ nor the existing requirements in subpart A explicitly explain the responsibilities for the situations for which reporters have requested guidance.

Therefore, the EPA is proposing to add specific provisions to subpart A that would define which owner or operator is responsible for current and future reporting years' reports and clarify how to determine responsibility for revisions to annual reports for reporting years prior to owner or operator changes for specific industry segments in subpart W, beginning with RY2023 reports. The provisions would also specify when an owner or operator should submit an annual report using an e-GGRT identifier assigned to an existing facility and when an owner or operator should register a new facility in e-GGRT. As described in more detail in this section, the provisions would vary based upon whether the selling owner or operator will retain any emission sources, the number of purchasing owners or operators, and whether the purchasing owners or operators already report to the GHGRP in the same industry segment and basin or state (as applicable). The proposed provisions would apply in lieu of 40 CFR 98.4(h) for these industry segments. These proposed revisions are expected to improve data quality as described in section II.A.4 of this preamble by ensuring that the EPA receives a more complete data set, and they are also expected to improve understanding of the rule, as described in section II.A.5 of this preamble.

We expect all the transactions will fall into one of four general categories, and we are proposing provisions that would define the responsibilities for reporting for each of those general categories. First, if the entire facility is sold to a single purchaser and the purchasing owner or operator does not already report to the GHGRP in that industry segment (and basin or state, as applicable), then we are proposing that the facility's certificate of representation must be updated within 90 days of the transaction to reflect the new owner or operator. In other words, the e-GGRT identifier and associated facility within e-GGRT would be transferred from the seller to the purchaser. The purchasing owner or operator would be responsible for submitting the facility's annual report for the entire reporting year in which the acquisition occurred (*i.e.,* the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter. In addition, because the definitions of facility for each of these segments encompass all of the emission sources in a particular geographic area (*i.e.,* basin, state, or nation), the purchasing owner or operator would include any previously owned applicable emission sources in the same geographic area as part of the purchased facility beginning with the reporting year in which the acquisition occurred.

Second, if the entire facility is sold to a single purchaser and the purchasing owner or operator already reports to the GHGRP in that industry segment (and basin or state, as applicable), then we are proposing that the purchasing owner or operator would merge the acquired facility with their existing facility for purposes of reporting under the GHGRP. In other words, the acquired facility would become part of the purchaser's existing facility under the GHGRP and emissions for the combined facility would be reported under the e-GGRT identifier for the purchaser's existing facility. The purchaser would update the acquired facility's certificate of representation within 90 days of the transaction to reflect the new owner or operator. The purchaser would then follow the provisions of 40 CFR 98.2(i)(6) to notify the EPA that the purchased facility has merged with their existing facility and would provide the e-GGRT identifier for the merged, or reconstituted, facility. Finally, the purchaser would be responsible for submitting the merged facility's annual report for the entire reporting year in which the acquisition occurred (*i.e.,* the owner or operator as of December 31 would be responsible for the report for that entire reporting year) and each reporting year thereafter.

Third, if the selling owner or operator retains some of the emission sources and sells the other emission sources of the seller's facility to one or more purchasing owners or operators, we are proposing that the selling owner or operator would continue to report under subpart W for the retained emission sources unless and until that facility meets one of the criteria in 40 CFR 98.2(i) and complies with those provisions. Each purchasing owner or operator that does not already report to the GHGRP in that industry segment (and basin or state, as applicable) would begin reporting as a new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The new facility would include the acquired applicable emission sources as well as any previously owned applicable emission

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[4] In the 2016 proposed rule, we specified "Suppliers of fluorinated HTFs would be subject to the same thresholds as suppliers of fluorinated GHGs. That is, there would be no threshold for producers of fluorinated HTFs, but the threshold for importers, exporters, and destroyers of fluorinated HTFs would be 25,000 mtCO$_2$e of fluorinated HTFs or GHGs." (81 FR 2572, January 15, 2016).

[5] U.S. EPA. *Q749: "What are the notification requirements when an Onshore Petroleum and Natural Gas Production facility, reporting under subpart W, sells wells and associated equipment in a basin?"* September 26, 2019. *https://ccdsupport.com/confluence/pages/viewpage.action?pageId=198705183.* Note that although FAQ Q749 specifically describes facilities in the Onshore Petroleum and Natural Gas Production segment, the EPA does consider the scenarios described to be relevant to the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment as well, because facilities in both segments are defined at the basin level rather than at the level of the subpart A definition of facility.

sources. Each purchasing owner or operator that already reports to the GHGRP in that industry segment (and basin or state, as applicable) would add the acquired applicable emission sources to their existing facility for purposes of reporting under subpart W and would be responsible for submitting the annual report for their entire facility, including the acquired emission sources, for the entire reporting year beginning with the reporting year in which the acquisition occurred.

Fourth, if the selling owner or operator does not retain any of the emission sources and sells all of the facility's emission sources to more than one purchasing owner or operator, we are proposing that the selling owner or operator for the existing facility would notify the EPA within 90 days of the transaction that all of the facility's emission sources were acquired by multiple purchasers. The purchasing owners or operators would begin submitting annual reports for the acquired emission sources for the reporting year in which the acquisition occurred following the same provisions as in the third scenario. In other words, each owner or operator would either begin reporting their acquired applicable emission sources as a new facility or add the acquired applicable emission sources to their existing facility.

Finally, for all of these types of transactions, we are proposing one set of provisions to clarify responsibility for annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. This set of proposed provisions would apply to annual GHG reports for facilities where these types of transactions occur after the effective date of the final amendments, if adopted. In other words, if the effective date of the final amendments is January 1, 2023, as described in section V of this preamble, then for ownership transactions that occur on or after January 1, 2023, we are proposing that the proposed requirements for the current and future reporting years described in the previous paragraphs would apply. In addition, the proposed provisions for annual GHG reports for reporting years prior to the transaction would also apply. For example, if an ownership transaction occurs on June 30, 2025, then the selling owner or operator and purchasing owner or operator would follow the applicable provisions previously described in this section for the RY2025 report and for future reporting years. We are also proposing that the provisions described in the next paragraph would apply for RY2024 and prior years' reports.

Specifically, we are proposing that as part of each ownership transaction described previously in this section, the selling owner or operator and purchasing owner or operator would agree upon the entity that would be responsible for revisions to annual GHG reports for previous reporting years. That entity would then select a representative for each facility that would respond to any EPA questions regarding GHG reports for previous reporting years and would submit corrected versions of GHG reports for previous reporting years as needed. If that individual is not the designated representative for the facility, the individual would need to be appointed as the alternate designated representative or an agent for the facility. In many situations, particularly for the first two categories of transactions described in this section, the EPA expects that the purchaser would agree to select a representative to address revisions to previous years' annual GHG reports. In addition, there may be cases in which the selling owner or operator's company will no longer be operating after the transaction, so it may be appropriate for one of the purchasing owners or operators to select that representative. In other situations, the parties may determine that it is appropriate for the seller to select the representative to address revisions to annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. Alternatively, parties to the transaction may agree on another independent party that would act as the representative regarding annual GHG reports for previous reporting years, such as a consultant. The EPA expects that the decision regarding the responsible entity would be made as part of the acquisition agreement or ownership transfer contract between the selling owner or operator and purchasing owner or operator and that if the entity responsible for revisions to annual GHG reports is not the selling owner or operator, copies of the records required to be retained per 40 CFR 98.3(g) and (h) would be transferred to the responsible entity at that time.

We are also proposing to amend 40 CFR 98.1(c) to clarify that the terms ''owner'' and ''operator'' used in subpart A have the same meaning as the terms ''gathering and boosting system owner or operator'' and ''onshore natural gas transmission pipeline owner or operator'' for the Onshore Petroleum and Natural Gas Gathering and Boosting and Onshore Natural Gas Transmission Pipeline industry segments of subpart W, respectively. This paragraph was inadvertently not amended when those two industry segments and the industry segment-specific definitions of owner or operator were added to subpart W (80 FR 64275, October 22, 2015), and this proposed amendment would correct that oversight.

In addition, we are proposing to revise 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. According to 40 CFR 98.3(h) a substantive error may either be identified by the EPA or discovered by the facility itself. If discovered by the facility, a revised report correcting the error must be submitted within 45 days. If identified by the EPA, once the facility is notified of the error, the facility must either resubmit the corrected report or provide information demonstrating that the previously submitted report does not contain the identified substantive error within 45 days. The rule also states that if requested in either case, the EPA may provide reasonable extensions to the 45-day period, including an automatically granted extension of 30 days. Additional extensions may be granted if the facility submits a request that is received prior to the expiration of the automatic 30-day extension. The current rule states that the Administrator will approve the additional extension request if the request demonstrates that it is not practicable to collect and process the data needed to resolve potential reporting errors within 75 days. However, since the GHGRP was implemented, we have encountered instances where a facility has repeatedly requested an extension of the time period by which they must either submit a revised report or provide information that the previously submitted report does not contain a substantive error. As such, the EPA cannot verify the facility's report in a timely manner. To avoid such instances in the future, we are proposing to add to 40 CFR 98.3(h)(4) that the Administrator will only approve extension requests for a total of 180 days from the initial notification of a substantive error. We expect 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.

The EPA is also proposing revisions to two terms consistent with the proposed amendments for reporting for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day described in section III.J of this preamble. The EPA is proposing to amend the definition of ''dehydrator vent emissions'' in 40 CFR 98.6 to confirm that dehydrator emissions reporting should include emissions from both the dehydrator still vent, and if applicable, the dehydrator flash vent. Additionally, the EPA is proposing to amend the definition of ''vapor recovery system'' in 40 CFR 98.6 to clarify that routing emissions from a dehydrator vent to the regenerator firebox/fire tubes does not qualify as vapor recovery. The EPA has noted significant variability in the dehydrator emissions values reported over the past several years, with values ranging from extremely high to almost negligible emissions, which indicates that there are likely inconsistencies in how these terms are being interpreted among subpart W reporters. In making these clarifying edits, the EPA expects to improve the quality of the emissions data reported and alleviate any confusion surrounding the applicability of these terms.

As a corollary to proposed amendments to subpart W to remove desiccant dehydrators as an emissions source, we are proposing to remove the definition of ''desiccant'' and to revise the definition of ''dehydrator'' in 40 CFR 98.6. The definition of ''desiccant'' would no longer be needed if the emission calculation and reporting requirements for desiccant dehydrators are removed from subpart W, as discussed in section III.J of this preamble. Similarly, the definition of ''dehydrator'' would no longer need to include a reference to desiccant. Thus, we are proposing to revise the definition of ''dehydrator'' to indicate that a dehydrator is ''a device in which a liquid absorbent (*e.g.,* ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.''

We are proposing revisions to 40 CFR 98.6 to add a definition for ''Direct air capture'' and amend the definition of ''Carbon dioxide stream''. These proposed changes are being made in conjunction with other proposed revisions to subpart PP of part 98 (Suppliers of Carbon Dioxide) and are discussed in section III.T of this preamble.

In addition, we are proposing two harmonizing changes 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) for subpart Q (Iron and Steel Production) and CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* for proposed subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916). These proposed changes are further described in sections III.H and III.W of this preamble.

Lastly, we are proposing two updates to Table A–1, the list of GWPs used in the GHGRP, to revise GWPs that, based on recent information, overestimate the atmospheric impacts of certain compounds by a large margin (*i.e.,* by factor of 2,000). We are not proposing any other updates to the Table A–1 GWPs. First, we are proposing to adopt a chemical-specific GWP for carbonic difluoride (COF_2). Emissions of COF_2 of 1–2 metric tons per year have been reported under the GHGRP from fluorinated gas production. (Carbonic difluoride is also used in the electronics industry as an etching agent and surface treatment, although emissions of COF_2 from electronics manufacturing have not been reported under the GHGRP). No peer-reviewed, chemical-specific GWP was available for COF_2 in 2014, when we last updated the set of GWPs in Table A–1 (79 FR 73750, December 11, 2014). It is therefore currently classified as an ''Other fluorinated GHG'' and is assigned a default GWP of 2,000 under the GHGRP. However, the World Meteorological Organization (WMO) recently published an atmospheric lifetime, radiative efficiency, and GWP for COF_2 in its *Scientific Assessment of Ozone Depletion*[6] (2018). Like the IPCC Assessment Reports upon which the GWPs in Table A–1 are based, the WMO Scientific Assessments include regularly updated international reviews of the scientific findings on the impacts of trace gases in the atmosphere, including their atmospheric lifetimes and radiative efficiencies. According to the 2018 WMO Scientific Assessment, COF_2 has a lifetime of approximately seven days, and 20-year and 100-year GWPs of less than one. The 2018 WMO Scientific Assessment listed the 100-year GWP of COF_2 as ''<1,'' so we calculated and are proposing a precise GWP for COF_2 of 0.14 using the atmospheric lifetime and radiative efficiency provided in the 2018 WMO Scientific Assessment. (The method we used to calculate the GWP of COF_2 was the method we used to calculate precise GWPs for low-GWP compounds in the most recent update to GHGRP GWPs (79 FR 73750, December 11, 2014)). This recent information supports that including a chemical-specific GWP for COF_2 of 0.14 would reflect its atmospheric impacts far more accurately than the currently applied GHGRP default GWP of 2,000.

Second, we are proposing to expand one of the F–GHG groups to which a default GWP of 1 is applied to include additional unsaturated fluorocarbons. The ninth F–GHG group in Table A–1 to subpart A currently includes unsaturated PFCs, unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, fluorinated aldehydes, and fluorinated ketones. We are proposing to add unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, and unsaturated hydrobromochlorofluorocarbons to this set. These F–GHGs do not have chemical-specific GWPs in Table A–1, and facilities and suppliers that currently report these F–GHGs generally classify them as ''Other fluorinated GHGs,'' which are assigned a default GWP of 2,000. However, two lines of evidence indicate that unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, and unsaturated hydrobromochlorofluorocarbons are likely to have GWPs near 1. First, like many of the types of compounds currently included in the ninth F–GHG group, they are unsaturated (*i.e.,* they include double and triple bonds between carbon atoms), and unsaturated GHGs in general tend to have very short atmospheric lifetimes and GWPs near or below 1. Second, evaluations of individual unsaturated chlorofluorocarbons and unsaturated bromofluorocarbons have all found very short atmospheric lifetimes and (where assessed) low GWPs for these compounds. The 2018 WMO Scientific Assessment provides atmospheric lifetimes for three unsaturated chlorofluorocarbons and four unsaturated bromofluorocarbons, and it provides an atmospheric lifetime and a 100-year GWP for one unsaturated

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

bromochlorofluorocarbon (4-bromo-3-chloro-3,4,4-trifluoro-1-butene). All of the atmospheric lifetimes are under 8 days,[7] and the 100-year GWP is listed as ''<1.'' Therefore, the EPA's assessment is that, due to their short atmospheric lifetimes, unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, and unsaturated hydrobromochlorofluorocarbons are likely to have a GWP near 1 (the default GWP for the ninth F–GHG group) rather than 2,000 (the default GWP for ''Other Fluorinated GHGs''). The EPA is proposing to add these additional unsaturated fluorocarbons to the ninth F–GHG group to result in more accurate estimation of the reported mtCO$_2$e.

We are proposing to incorporate a harmonizing change based on the addition of a new source category for quantifying geologic sequestration in association with EOR operations. Specifically, we are proposing to add the new subpart, subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916), in Table A–3 to subpart A.

As discussed in section III.W of this preamble, facilities that conduct EOR currently have the option to either report basic information on CO$_2$ received under subpart UU (Injection of Carbon Dioxide), or report CO$_2$ sequestered under subpart RR (Geologic Sequestration of Carbon Dioxide). Facilities that conduct EOR are not required to report under subpart RR unless the owner or operator chooses to opt-in to subpart RR, or the well is permitted as an Underground Injection Control (UIC) Class VI well. We are proposing that facilities that use the standard *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO$_2$-EOR)* (CSA/ANSI ISO 27916:2019) for quantifying geologic sequestration of CO$_2$ in association with EOR operations would similarly have the option to report under the proposed subpart VV instead of subpart UU. Facilities that conduct EOR would therefore have two options to report amounts of CO$_2$ that are geologically sequestered: subpart RR or subpart VV.

We are proposing to include the new subpart VV in Table A–3 to subpart A. In addition, we are proposing that this new subpart would not include a reporting threshold for applicability. The EPA previously promulgated subparts RR and UU with no threshold (*i.e.,* as ''all-in'' source categories in Table A–3 to subpart A) due to variability in CO$_2$ injection amounts from year to year and based on limited knowledge of which EOR reporters that are not required to report under subpart RR would choose to report geologic sequestration (see 75 FR 18454, April 10, 2010 and 75 FR 75070, December 1, 2010). The facilities affected by the proposed subpart include facilities that are currently reporting under subpart UU and that do not currently report amounts of CO$_2$ sequestered. The EPA is proposing no threshold for the proposed subpart VV so that all EOR facilities that quantify CO$_2$ sequestration using the CSA/ANSI ISO 27916:2019 standard and that do not report under subpart RR would have the option to either report under the proposed subpart VV, or would otherwise continue to report under subpart UU. For these reasons, we do not anticipate that the new subpart would increase the number of facilities subject to the GHGRP. Further, it is difficult to predict how many injection facilities would choose to report using the ISO standard in lieu of continuing to report under subpart UU. Therefore, we are proposing that subpart VV would be an ''all-in'' reporting subpart in order to allow the Agency to continue to comprehensively track all CO$_2$ that is injected underground, and to remain consistent with the ''all-in'' requirements for EOR or injection facilities that currently report under subparts RR or UU. Reporters who choose to report under this subpart would be required to meet the requirements of 40 CFR 98.2(a)(1). However, as proposed in new 40 CFR 98.480(c), facilities subject only to new 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 the existing facilities under subpart UU.

Additionally, we are proposing that facilities subject to proposed subpart VV would not be required to meet the off-ramp requirements of 40 CFR 98.2(i). Instead, once a facility opts-in to proposed 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 27916:2019. The EPA is proposing that the operator 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 27916:2019. See section III.W of this preamble for additional details on the proposed revisions.

2. Proposed Amendments To Streamline and Improve Implementation for Subpart A

For the reasons described in sections II.B.1, III.N, and III.U of this preamble, we are proposing harmonizing edits in subpart A of part 98 to revise the rule applicability for subparts DD (Electrical Transmission and Distribution Equipment Use) and subpart SS (Electrical Equipment Manufacture or Refurbishment). The proposed applicability threshold for subparts DD and SS would be based on total emissions equivalent to the 25,000 mtCO$_2$e or more per year, rather than the current threshold levels that are based on the total nameplate capacity of the equipment or the annual consumption, respectively. For subpart DD, we are proposing to revise Table A–3 such that the threshold is based on total estimated emissions from F–GHGs, as determined under 40 CFR 98.301 (subpart DD), that are equivalent to 25,000 mtCO$_2$e or more per year. For subpart SS, we are proposing to revise Tables A–3 and Tables A–4 such that: (1) subpart SS would be removed from Table A–3; and (2) Table A–4 would be revised to specify that subpart SS facilities would be included in 40 CFR 98.2(a)(2) and Table A–4, as determined under the requirements of 40 CFR 98.451 (subpart SS), which provide estimation methods for total estimated emissions from F–GHGs for comparison to a threshold equivalent to 25,000 mtCO$_2$e or more per year. Refer to sections III.N and III.U of this preamble for a detailed discussion of these proposed changes and how the proposed new thresholds would be implemented. The proposed revisions are intended to harmonize Tables A–3 and A–4 with the proposed changes described in sections II.B.1, III.N, and III.U of this preamble, which would update the threshold to be consistent with the threshold set for the majority of subparts and would account for additional fluorinated gases (including F–GHG mixtures) reported by industry, and for subpart DD, would also streamline the reporting requirements to

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[7] The IPCC Fifth Assessment Report lists 100-year GWPs of less than one for all the compounds for which the report lists an atmospheric lifetime of less than 8 days. The IPCC Fifth Assessment Report is the source of the chemical-specific GWPs for the compounds in the ninth F–GHG group in Table A–1. See 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. *https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf.*

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$_2$e per year (see section IV.C (''Rationale for Selection of Thresholds'') of the preamble to the 2009 Proposed Rule (74 FR 16467, April 10, 2009)).

B. Subpart C—General Stationary Fuel Combustion Sources

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

We are proposing several amendments to improve the quality of the data collected under subpart C of part 98 (General Stationary Fuel Combustion Sources). This section describes the specific changes proposed.

First, for the reasons provided in section II.A.2 of this preamble, we are proposing to modify the Tier 3 calculation methodology in subpart C. Reporters to subpart C may use the Tier 3 methodology provided in 40 CFR 98.33(a)(3) for determining annual CO$_2$ emissions from combustion units. The Tier 3 methodology requires a calculation based on annual fuel use, measured carbon content, and for gaseous fuels, measured molecular weight. For gaseous fuels, equation C–5 at 40 CFR 98.33(a)(3)(iii) requires that the carbon content and molecular weight be in units of kilogram (kg) C/kg fuel and kg/kg-mole, respectively, and be determined using the same procedures as specified for high heating value (HHV) at 40 CFR 98.33(a)(2)(ii). However, when using equation C–2b at 40 CFR 98.33(a)(2)(ii)(A) in this manner, the fuel carbon content is on a mass basis (*i.e.,* kg C/kg fuel) while the fuel flow is on a volumetric basis (*i.e.,* scf), resulting in a weighting factor that is potentially problematic because the units of measure are not in equivalent terms, *i.e.,* the average annual carbon content should be in mass terms (*i.e.,* kg C/kg fuel). When using equation C–2b for calculating an annual flow-weighted molecular weight, a similar situation occurs. This has been the case since the 2009 Final Rule (74 FR 56397).

To address this matter, the EPA is proposing to modify the Tier 3 calculation methodology in 40 CFR 98.33(a)(3)(iii) to provide new equations C–5a and C–5b for calculating a weighted annual average carbon content and a weighted annual average molecular weight. respectively. These new proposed 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. This proposed change will correct the calculation method for Tier 3 gaseous fuels. The EPA does not expect a significant change in reported emissions because the change to the values for carbon content and molecular weight is expected to be minimal under the proposed calculation methods. Additionally, some reporters have previously exercised the option to manually override the calculated emission values with their own calculated values to address this issue when it has been identified.

We are also proposing several revisions to rule provisions pertaining to the calculation of biogenic emissions from tire combustion to improve the existing calculation methodology. First, for the reasons described in section II.A.2 of this preamble, the EPA is proposing to revise the calculation methods that must be used to determine the total annual CO$_2$ emissions under 40 CFR 98.33(e)(3)(iv)(A) when determining the biogenic CO$_2$ emissions of MSW or tires under 40 CFR 98.33(e)(3)(iv). Currently, 40 CFR 98.33(e)(3)(iv) provides procedures in certain circumstances to estimate the annual biogenic CO$_2$ emissions in the combustion of MSW or tires, which start with requiring that the Tier 1 calculation method be used to determine the total annual CO$_2$ emissions from MSW or tires under 40 CFR 98.33(e)(3)(iv)(A). The value determined under 40 CFR 98.33(e)(3)(iv)(A) is then multiplied by the applicable default biogenic fraction specified at 40 CFR 98.33(e)(3)(iv)(B) to determine the total biogenic CO$_2$ emissions. At the same time, 40 CFR 98.33(a) provides four calculation methodologies, Tier 1 through 4, and an alternative methodology for certain units subject to 40 CFR part 75, for calculating CO$_2$ emission for fuel combustion. In certain circumstances, a reporter may be required under 40 CFR 98.33(a) to calculate CO$_2$ emissions from combustion of MSW or tires using Tiers 2 or 3 for the purposes of annual reporting, but then must also calculate the total CO$_2$ emissions using Tier 1 under 40 CFR 98.33(e)(3)(iv)(A) for the purpose of determining and reporting the biogenic CO$_2$ emissions from combustion of MSW or tires under 40 CFR 98.33(e)(3)(iv). This has previously resulted in some confusion for reporters where total CO$_2$ emissions are calculated twice using different tiers, one tier for one aspect of annual reporting and another tier for biogenic calculation and reporting, and a redundancy in calculation of total CO$_2$ emissions by reporters. This has also resulted in some confusion when comparing the calculated total CO$_2$ emissions under 40 CFR 98.33(a) to the estimated total biogenic CO$_2$ emissions under 40 CFR 98.33(e)(3)(iv), since they are based on different calculation methodologies. The EPA is proposing to revise 40 CFR 98.33(e)(3)(iv)(A) so that total annual CO$_2$ emissions will be calculated using the applicable methodology in paragraphs 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 paragraph 40 CFR 98.33(a)(1) for units using the Tier 4 or part 75 for purposes of 40 CFR 98.33(a), when determining the biogenic component of MSW or tires under 40 CFR 98.33(e)(3)(iv).

The EPA is proposing two additional substantive revisions to the procedures for calculating and reporting emissions of biogenic CO$_2$ from the combustion of tires. First, for the reasons discussed in section II.A.1 of this preamble, we are proposing to update a default factor that is used to determine biogenic CO$_2$ emissions from the combustion of tires. Separately reporting the biogenic CO$_2$ emissions (*i.e.,* specifying which emissions are biogenic) from the combustion of tires is currently optional, but if a reporter elects to do so, then 40 CFR 98.33(e)(3) specifies the calculation procedure. Under 40 CFR 98.33(e)(3), if tires provide more than 10 percent of the annual heat input to a unit and the owner or operator elects to separately report the biogenic CO$_2$ emissions from the combustion of tires, then the owner or operator must conduct testing using ASTM method D6866–16, *Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis* (2016) and ASTM method 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* (2016) to determine the biogenic fraction of CO$_2$.[8] But if tires provide 10 percent or less of the annual heat input, then reporters have the option to separately report the biogenic CO$_2$ emissions by multiplying the total CO$_2$ emissions by a default factor of 0.20. The 0.20 factor is based on

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[8] ASTM D7459–08 was approved for use in the October 30, 2009 final rule (74 FR 56291), see Docket Id. No. EPA–HQ–OAR–2008–0508. ASTM D6866–16 was approved for use in the December 9, 2016 final rule (81 FR 89196), see Docket Id. No. EPA–HQ–OAR–2015–0526.

information from the Rubber Manufacturers Association (RMA) that was based on most current data available at the time of the publication of the GHG Reporting Rule revisions in the **Federal Register** on December 17, 2010 (75 FR 79092) (hereafter referred to as the 2010 Final Revisions Rule) and represented an arithmetic average of the natural rubber content (*i.e.,* composition) of passenger and commercial tires sold and thus available for combustion.[9] Since publication of the 2010 Final Revisions Rule, we have received a memorandum from the U.S. Tire Manufacturers Association (USTMA, formerly RMA) that based on updated data, the weighted average composition of natural rubber in tires is now 24 percent.[10] [11] The proposed default value was calculated by weighting the average rubber content, average weight, and shipment percentage of both light duty vehicle and commercial vehicle scrap tires, which is more accurate than would result from using the arithmetic average. In addition to the comments and information provided by the USTMA, the Portland Cement Association (PCA) provided supporting information from one of its member companies, Mitsubishi Cement. Operational data (total count and weight of tires combusted) and analytical data (percent of biogenic carbon based on ASTM D6866–20) from 2020 was provided.[12] The EPA reviewed these data and determined that they support the USTMA's recommended 0.24 default biogenic fraction for tires.[13] We are therefore proposing to revise 40 CFR 98.33(e)(3)(iv)(B) to update the default biogenic fraction to 0.24.[14]

Second, for the reasons described in section II.A.3 of this preamble, we are proposing that all units that combust tires must separately report biogenic CO_2 emissions. The separate reporting of biogenic CO_2 from tires was made optional in a 2010 final rule (75 FR 79100, December 17, 2010). For that rulemaking, we received no public comments on the proposal to make separate biogenic CO_2 emissions reporting optional for the combustion of tires, and the proposal was finalized without modification. In the final rule preamble, however, we stated: ''No comments were received on the proposal to make biogenic CO_2 emissions reporting optional for the combustion of tires, and the proposal has been finalized without modification. However, tire-derived fuel has a biomass component, and perhaps it should be treated in the same manner as MSW, which is also partly biogenic. A number of units that are subject to part 98 combust tires as the primary fuel or as a secondary fuel. Therefore, we are considering whether these units should be required to separately account for their biogenic CO_2 emissions. However, before making this mandatory we intend to open it to notice and comment in a future rulemaking'' (75 FR 79109). In conjunction with this change, we are proposing to remove the restriction in 40 CFR 98.33(e)(3)(iv) that the default factor 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.'' Following the 2010 Final Revisions Rule, reporters that chose to optionally report biogenic CO_2 emissions from tire combustion were required to use quarterly flue-gas testing using ASTM methods, except that small units (*i.e.,* units in which tires provide no more than 10 percent of the annual heat input to a unit) could alternatively use the default factor. The proposal to remove the current restriction allowing only small units to use the default factor (*i.e.,* allowing the use of the default factor for all units that combust tires), when combined with the proposed requirement to report biogenic CO_2 emissions from tire combustion, would result in a more accurate characterization of emissions from larger units since no units that combust tires alone or in conjunction with fossil fuels have reported, for RY2015 through RY2018, biogenic CO_2 emissions that were calculated using the quarterly flue-gas testing results. Therefore, the proposed addition of reporting of biogenic CO_2 emissions for tire combustion should require no additional monitoring or data collection and could be reported with minimal additional reporting burden. The EPA is proposing that this change would only be finalized if the proposed requirement to report biogenic CO_2 emissions from tire combustion is also finalized. Additionally, we are proposing another change that would only be finalized if the proposed requirement to report biogenic CO_2 emissions from tire combustion is also finalized. Specifically, 40 CFR 98.33(b)(1)(vii) currently allows units that combust MSW and/or tires to use Tier 1 if the combined heat input from both fuels is not greater than 10 percent of the heat input to the unit but also provides that, if a reporter choose the option to not report biogenic CO_2 from tire combustion, the 10 percent threshold applies only to the MSW fuel. If the proposed mandatory reporting of biogenic CO_2 from tire combustion is finalized, we are proposing that the additional provision in 40 CFR 98.33(b)(1)(vii) on how to apply the threshold to only MSW fuel would be deleted, since it would no longer be applicable. This may result in fewer facilities being able to use Tier 1 to calculate MSW and/or tire CO_2 emissions since the tire heat input would now always be included in conjunction with the MSW heat input to compare to the 10 percent threshold.

In conjunction with these proposed revisions, we are also proposing to remove the language in 40 CFR 98.33(e) and 40 CFR 98.36(e)(2)(xi) referring to optional biogenic CO_2 emissions reporting from tire combustion, and to revise 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). We are proposing the latter change because 40 CFR 98.34(d) incorrectly references 40 CFR 98.33(b)(1)(vi) and (vii), which specify certain provisions when Tier 1 can be used, whereas 40 CFR 98.33(e)(3)(iv) specifies when the default biogenic factor for MSW can be used (*i.e.,* in cases where 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) and is the correct reference for 40 CFR 98.34(d). This revision is being proposed to correct this reference in accordance with other proposed changes. Additionally, we are proposing a clarifying correction to 40 CFR 98.33(e), *Biogenic CO_2 emissions from combustion of biomass with other fuels.* Section 98.33(e)(1) specifies that equation C–1 of subpart C can be used to calculate the annual CO_2 mass emissions from the combustion of the biomass fuels listed in Table C–1 of this subpart (except MSW and tires). We are proposing to delete the parenthetical clause ''(except MSW and tires)'' in 40 CFR 98.33(e)(1) because, although MSW and tires are partially biogenic, they were never categorized as biomass fuels

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[9] Please refer to the memorandum, *Natural Rubber Fraction in Tire Derived Fuel* by Matt Hakos and Cassy Becker, RTI International to Michael Hannan, EPA (August 2021), available in the docket for this rulemaking, Docket Id. No EPA–HQ–OAR–2019–0424, for more detail.

[10] See the memorandum, *Methodology for Determining the Natural Rubber Fraction in Tire Derived Fuel,* by Sarah Amick and Jesse Levine, USTMA to U.S. EPA (April 11, 2019), available in Docket Id. EPA–HQ–OAR–2019–0424.

[11] *Supra* note 9.

[12] See ''Tire Biogenic Content Data Provided by the Portland Cement Association'' (August 2021), available in Docket Id. EPA–HQ–OAR–2019–0434.

[13] *Supra* note 9.

[14] *Supra* note 9.

in Table C–1 of subpart C and thus no aspect of Table C–1 was excepted by this parenthetical clause. This deletion would correct the drafting oversight and will not result in any change to the reporting requirements.

Next, for the reasons discussed in section II.A.5 of this preamble, we are proposing to correct the equation C–11 term definition for the variable ''R''. Equation C–11 is used to calculate the CO_2 emissions from sorbent use when the chemical reaction between the acid gas and sorbent produces CO_2 emissions and when these emissions are not monitored with a CEMS. 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). However, the units of measure for the equation as presented do not currently result in metric tons CO_2 emitted. We are proposing to revise the definition of the term ''R'' as ''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)'' so that the equation is dimensionally correct (*i.e.,* results in metric tons CO_2 emitted).

We are also proposing to amend 40 CFR 98.33(c)(6)(i), (ii), (ii)(A), and (iii)(C), and delete (ii)(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. There would be no new reporting requirements because of this proposed clarification.

For the reasons described in section II.A.4 of this preamble, we are proposing a substantive revision to rule provisions pertaining to the reporting of unit level information for the aggregation of units and common pipe configurations. Currently, subpart C allows facilities to report data using six different configurations. These configurations are:

- Individual unit using Tiers 1, 2, or 3 to calculate emissions.
- Individual unit using Tier 4 to calculate emissions.
- Group of units using the aggregation of units reporting alternative with Tiers 1, 2 or 3.
- Group of units using the common pipe configuration reporting alternative with Tiers 1, 2, or 3.
- Group of units using Tier 4 to calculate emissions and reporting under the monitored common stack or duct configuration reporting alternative.
- Part 75 units using the alternative CO_2 mass emissions calculation methods.
- For RY2019, the approximate use of reporting configurations and the percent of emissions for each is summarized:

Configuration type	Number of Subpart C configurations	Percent of total Subpart C configurations	Percent of total Subpart C CO_2 emissions
Individual Unit (Tiers 1–3)	9,185	58	36
Individual Unit (Tier 4)	208	1	9
Aggregation of Units (Tiers 1–3)	4,362	27	24
Common Pipe (Tiers 1–3)	1,905	12	26
Common Stack (Tier 4)	21	0.1	2
Alternative Part 75	192	1	2

Individual unit information (*i.e.,* the unit type and the maximum rated heat input capacity) is currently only required to be reported for the individual unit (Tiers 1–3 and Tier 4) reporting configurations. The individual unit information allows the EPA to aggregate emissions according to unit type and size and provides a better understanding of the emissions from specific unit types.

Individual unit information is not reported for the aggregation of units, common pipe, common stack, or alternative part 75 reporting configurations. As such, the EPA is currently unable to aggregate emissions by unit type and size for these reporting configurations, which represent 40 percent of the configurations used and 54 percent of the emissions reported in subpart C.

The aggregation of units and common pipe configurations are the second and third most used configurations and together, they represent approximately 39 percent of the configurations and 50 percent of the emissions reported to subpart C. Both of these reporting alternatives allow multiple units to be reported under one configuration group. Because the unit type and maximum rated heat input capacity are currently not reported for the individual units within these two configurations, there is a significant gap in the EPA's ability to aggregate subpart C emissions data by unit type and size.

To better analyze reported data by unit type and size, the EPA is proposing to revise 40 CFR 98.36(c)(1) and (3) (by adding 40 CFR 98.36(c)(1)(ii) and (c)(3)(xi)) to require reporting for each unit in either an aggregation of units or common pipe configuration, excluding units less than 10 mmBtu/hr from both, of the unit type, maximum rated heat input capacity, and an estimate of the fraction of the total annual heat input. Under the proposed amendments, unit level information would be reported for four of the six configuration types. This would allow the EPA to aggregate data according to unit type and size for approximately 98 percent of the configurations and 95 percent of the emissions in subpart C (the actual percent of emissions that could be aggregated by unit type would be somewhat lower than 95 percent because units less than 10 would be excluded from the additional reporting requirements) to provide unit level information for the aggregated unit and common pipe configurations. We expect the percent of emissions to be only somewhat lower than 95 percent because units less than 10 mmBtu/hr are estimated to have minor emissions contributions in aggregated unit and common pipe configurations, as previously described in the 2016 final rulemaking (81 FR 89203, December 9, 2016). Given the relatively low emissions from the common stack (Tier 4) and part 75 configurations, the EPA is not proposing to require reporting of individual unit information for these configurations at this time. The EPA seeks comment on whether to propose these requirements for the common stack (Tier 4) and part 75 configurations.

The proposed reporting requirements are not expected to significantly increase burden for reporters. The requirement to report the cumulative maximum rated heat input capacity for the aggregation of units or common pipe configurations began with the 2017 reporting year (81 FR 89188). Accordingly, facilities have been reporting cumulative maximum rated heat input capacity for four years. To determine this value, facilities must know the maximum rated heat input capacity of all units in each aggregation of units or common pipe configuration (greater than or equal to 10 mmBtu/hr), because these values are summed to determine the cumulative value. The EPA expects that the other requirements (*i.e.,* unit type and estimate of the fraction of annual heat input) can be determined from existing company records. The total fraction of annual heat input for each unit in the group will be determined by dividing the estimated actual heat input for that unit by the sum of the estimated actual heat input for all units in the group. Accordingly, any new burden incurred from this proposed requirement is expected to be minimal and associated with calculating the fraction of the total annual heat input and entering data into the e-GGRT software. To minimize the burden of reporting these data in e-GGRT, the EPA intends to evaluate developing a bulk unit details reporting form similar to the existing bulk equation input reporting forms for Tiers 2 and 3.

For the reasons described, the EPA has proposed these new reporting requirements under 40 CFR 98.36(c)(1)(ii) (aggregation of units) and 40 CFR 98.36(c)(3)(xi) (common pipe). These proposed amendments will better inform future policy and programs by addressing a data gap in unit information that currently exists for these two reporting configurations. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

As a corollary to proposed amendments to subpart W (Petroleum and Natural Gas Systems) to address uncombusted methane emissions from compressor drivers (see section III.J.1.n of this preamble), we are proposing that natural gas-fired compressor drivers located at facilities that are subject to subpart W would be required to use the CH_4 emission factors in Table W–9 to subpart W rather than the default CH_4 emission factor for natural gas in Table C–2 to subpart C. Specifically, we are proposing to revise the ‘‘EF’’ term in each of the equations in 40 CFR 98.33(c) (*i.e.,* equations C–8, C–8a, C–8b, C–9a, C–9b, and C–10) to reference the CH_4 emission factors in Table W–9 to subpart W for natural gas compressor drivers. We are also proposing to add a footnote to Table C–2 that specifies that for reporters subject to subpart W, the default CH_4 emission factor for natural gas may only be used for natural gas-fired combustion units that are not compressor drivers. Finally, we are proposing to amend 40 CFR 98.36(c)(1) and (c)(3). Under the proposed amendments, reporters may not report a combination of one design class of compressor driver (using one Table W–9 CH_4 emission factor) and other combustion units (*e.g.,* using a Table C–2 CH_4 emission factor or another Table W–9 CH_4 emission factor) in the same aggregation of units or common pipe configuration. This change would ensure that all units in an aggregation of units or common pipe configuration are using the same CH_4 emission factor for each fuel combusted in the unit.

We are proposing two additional clarifications to existing reporting and record keeping requirements, for the reasons described in section II.A.5 of this preamble. First, we are proposing to revise 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. The monthly HHV reporting requirement was always clear based on the language in this provision and the proposed clarification plainly states 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 e-GGRT). There are no new reporting requirements because of this proposed clarification.

Second, we are proposing to revise 40 CFR 98.37(b)(9), (10), (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) but was inadvertently omitted from being specified in those subparagraphs. These proposed 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 proposed revisions to equation C–5 at 40 CFR 98.33(a)(3)(iii), as noted above. These proposed revisions do not require any new action from affected reporters, as all new recordkeeping data proposed is already contained in the file generated by the verification software.

2. Proposed Revisions To Streamline Implementation and Reduce Burden for Subpart C

We are proposing several revisions to subpart C to streamline requirements and to adopt minor revisions to improve implementation of the rule.

For the reasons described in section II.B.2 of this preamble, the EPA is proposing to amend 40 CFR 98.34(c)(6). In the 2010 Final Revisions Rule (75 FR 79092), the EPA added 40 CFR 98.34(c)(6), which allowed cylinder gas audits (CGAs) of the CO_2 monitor to be performed using calibration gas concentrations of 40–60 percent and 80–100 percent of CO_2 span, when the CO_2 span value is set higher than 20 percent CO_2. Under appendix F of 40 CFR part 60, CGAs of the CO_2 analyzer are required at two calibration gas concentrations (*i.e.,* 5–8 percent and 10–14 percent CO_2 by volume). These CO_2 concentration levels are appropriate for certain stationary combustion applications (*e.g.,* a typical span value for a CO_2 monitor installed on a coal-fired boiler is 20 percent CO_2). These CGA concentrations represent 25–40 percent and 50–70 percent of the CO_2 span value, when the CO_2 span is at 20 percent CO_2. When the CO_2 span exceeds the typical span value of the fuel being evaluated (*e.g.,* 20 percent CO_2 on a coal-fired boiler), the CGA concentrations specified in part 60 are no longer representative, as they only evaluate the lower portion of the measurement scale. Since the EPA had information indicating that there were cases when the CO_2 span was set greater than 20 percent CO_2 (*e.g.,* process and combustion emissions from cement manufacturing may require 30 percent CO_2 span), 40 CFR 98.34(c)(6) was added so that CGAs could be conducted at two separate portions of the measurement scale, as opposed to just the lower portion (see 75 FR 79111, December 17, 2010).

Since 2010, the EPA has received questions through GHGRP Help Desk indicating that industrial flue gases also occur where the measured CO_2 concentration is very low (*e.g.,* natural gas turbines typically have about 5 percent CO_2 in flue gas). In this case, the required calibration gas concentrations (*i.e.,* 5–8 percent and 10–14 percent CO_2 by volume) under appendix F of 40 CFR part 60 would not be appropriate because they may be above the CO_2 span value and so would not provide information regarding accuracy of the monitor at actual representative stack gas concentrations. Accordingly, the EPA is proposing to amend 40 CFR 98.34(c)(6) to allow 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. This will allow CGAs to check the response of the CO_2 analyzer at two calibration gas concentrations, representing separate portions of the measurement scale, when the CO_2 span is significantly lower or higher than 20 percent CO_2.

For the reasons described in section II.B.3 of this preamble, the EPA is proposing to amend certain provisions in 40 CFR 98.36 that require facilities with the aggregation of units or common pipe configuration types to report the annual CO_2 mass emissions from the combustion of all fossil fuels, per the requirements in 40 CFR 98.36(c)(1)(vi) and 40 CFR 98.36(c)(3)(vi). The EPA has reviewed the data provided under these reporting requirements and has tentatively concluded that they are no longer required for the verification or analysis of subpart C annual reports. In addition, the reporting of this data for the aggregation of units or common pipe configuration types has caused confusion for reporters because they mistakenly believe that the value is used in subpart C total CO_2 emission calculations. Therefore, we are proposing to revise the provisions in 40 CFR 98.36(c)(1)(vi) and 40 CFR 98.36(c)(3)(vi) to remove the language requiring reporting of the total annual CO_2 mass emissions from all fossil fuels combined.

For these two configuration types (aggregation of units and common pipe), the reported configuration-level annual CO_2 emissions from all fossil fuels does not factor into any subpart- or facility-level total CO_2 emission calculations. The e-GGRT calculates the subpart-level non-biogenic CO_2 emissions for these two configuration types by summing the reported fuel-level CO_2 emissions values from each fuel, regardless of whether it is biogenic or not, then subtracting the reported configuration-level biogenic CO_2 emissions values. For the aggregation of units configuration type, the reported configuration-level sorbent CO_2 emissions value, which is typically zero, is also added into this ''rolled-up'' non-biogenic CO_2 emissions total. The calculation was specifically designed in this manner because the reported fuel-level information for Table C–1 partially biogenic fuels (*i.e.,* tires, MSW) and some ''other'' or ''blend'' fuels that contain biogenic material is not sufficient to allow the calculation of biogenic CO_2 emissions for each fuel such that it could be accurately subtracted from the fuel-level CO_2 emissions values. Thus, the reported configuration-level biogenic CO_2 emissions must be used in the subpart total calculations. Many reporters then assume that the configuration-level annual CO_2 emissions from all fossil fuels is also used in the subpart total calculations, which creates confusion for reporters and has resulted in GHGRP Help Desk submissions stating that these requirements are redundant and confusing. By proposing to revise the provisions in 40 CFR 98.36(c)(1)(vi) and 40 CFR 98.36(c)(3)(vi) to remove the language requiring reporting of the total annual CO_2 mass emissions from all fossil fuels combined, we would remove this unnecessary confusion for reporters with aggregation of units and common pipe configuration types.

C. Subpart G—Ammonia Manufacturing

For the reasons discussed in section II.A.2 of this preamble, we are proposing several revisions to subpart G of part 98 (Ammonia Manufacturing) to improve the quality of the data collected from this subpart. Subpart G estimates CO_2 emissions from ammonia manufacturing based on a carbon mass balance, which assumes that all carbon contained in feedstocks is transformed to CO_2 and all CO_2 is emitted from the ammonia manufacturing process. The EPA has received numerous comments from The Fertilizer Institute (TFI) related to the calculation of CO_2 emissions from the production of ammonia in subpart G. Most comments from TFI were related to the carbon mass balance methodology, especially with regard to other products that could be produced using the CO_2 emissions from ammonia production. TFI has asserted that most ammonia manufacturing facilities capture and use the CO_2 resulting from the ammonia manufacturing process to produce urea. Subpart G does not currently allow the subtraction of the CO_2 that is bound in urea from calculated and reported emissions or otherwise allow separate reporting of that CO_2.

In response to the 2009 Proposed Rule, TFI submitted a comment letter dated June 9, 2009, and provided comments via a public hearing on April 6, 2009, stating that the CO_2 produced through ammonia manufacturing is often utilized in the manufacturing of urea and that the EPA mistakenly assumed that all CO_2 in urea will be released into the atmosphere.[15] [16] In response, in the 2009 Final Rule, the EPA changed the rule requirements to collect information on urea production and uses of the urea if known, stating ''Collecting information on urea production and its uses will help [the] EPA to improve methodologies for estimating emissions from ammonia manufacturing, urea production and urea consumption in the future.''

The EPA next revised 40 CFR 98.72(a) and 40 CFR 98.73(b)(5) in subpart G (75 FR 79092, December 17, 2010) to explain that the ''CO_2 process emissions reported under this subpart may include CO_2 that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit.'' This revision was proposed pursuant to a settlement agreement with TFI, after TFI challenged the 2009 rulemaking.[17]

In response to an April 2, 2013 EPA-proposed rule (78 FR 19802), TFI submitted a comment letter dated May 2, 2013, requesting that the EPA revise subpart G to require only the reporting of CO_2 emitted directly to the atmosphere from the synthetic ammonia production process instead of continuing to include the CO_2 captured during ammonia production and used to produce urea, noting its view that the captured CO_2 ''does not contribute to the CO_2 emission estimates for ammonia production.'' [18] TFI further argued the existing methodology is inconsistent with other source categories covered by the rule (namely subpart P (Hydrogen Production) and subpart X (Petrochemical Production)) and is contrary to the EPA's methodology used in the U.S. GHG Inventory. TFI pointed to similarities between the structure of subpart G and subpart P, and argued that the structure of subpart G be revised to be more consistent with subpart X, which allows sources to account for carbon (*i.e.,* subtract from direct facility emissions) that is being shipped off-site in products. In response, the EPA responded that TFI had raised a consistency issue within part 98 that ''merits evaluation and requires further analysis by the EPA.'' However, the EPA explained that no changes were made at that time because TFI's comment was outside of the scope of the rulemaking.[19]

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[15] TFI's Comments on the ''*Proposed Mandatory Reporting of Greenhouse Gases Rule*'' Docket Id. No. *EPA–HQ–OAR–2008–0508–2376,* June 9, 2009. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[16] *USEPA Public Hearing for Proposed Rulemaking for Mandatory Reporting of Greenhouse Gases.* Transcript Day One of Two. April 6, 2009. Docket Id. No. EPA–HQ–OAR–2008–0508–0212. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[17] *The Fertilizer Institute* v. *EPA,* Docket Id. No. 09–1329 (D.C. Circuit), 2010. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[18] TFI's Comments on the Proposed ''*2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements,*'' Docket Id. No. EPA–HQ–OAR–2012–0934–0036, May 2, 2013. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[19] *Summary of Public Comments and Responses for Greenhouse Gas Reporting Rule: 2013 Revisions to the Greenhouse Gas Reporting Rule and Confidentiality Determinations for New or Substantially Revised Data Elements.* Docket Id. No.

Continued

In response to a January 15, 2016 EPA-proposed rule (81 FR 2536), TFI submitted a comment letter dated March 30, 2016, again requesting that part 98 be made consistent with the methodology used in the U.S. GHG Inventory, such that CO_2 bound in urea would not be considered an emission from the ammonia manufacturing process.[20] Also, TFI asked for clarification regarding a new requirement in subpart G to report the amount of methanol produced at the ammonia manufacturing facility. In response, the EPA noted the potential of using a future rulemaking to address TFI's suggested revisions ''to require reporting only CO_2 that is emitted directly to the atmosphere from ammonia manufacturing, rather than reporting CO_2 that is bound in the urea that is produced from ammonia at some facilities,'' but explained that the comment was outside the scope of that rulemaking. The EPA clarified in the preamble and in the final rule (81 FR 89188, December 9, 2016) that the quantity of methanol being reported only includes methanol that is ''intentionally produced as a desired product'' and does not include the quantity of methanol that is vented or destroyed.

TFI submitted two other comment letters in 2017. The letter dated March 31, 2017 was submitted to the Department of Commerce as part of a request for information ''Impact of Federal Regulations on Domestic Manufacturing'' (82 FR 12786, March 7, 2017).[21] The letter dated May 15, 2017 was submitted to the EPA's request for comment on ''Evaluation of Existing Regulations'' (82 FR 17793, April 13, 2017).[22] Both letters contained similar language asking that the GHGRP be amended to ''report the quantity of GHG that is actually emitted to the atmosphere as part of the manufacturing processes'' instead of ''GHG emissions that are captured and either sold or used in other industrial processes.''

After consideration of the comments from TFI summarized above, the EPA has tentatively concluded that requiring reporters subject to subpart G 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 would provide a more accurate estimate of the emissions and would provide consistency in our approach across the GHGRP. Therefore, for the reasons described in this section and in section II.A.2 of this preamble, we are proposing multiple amendments to subpart G. Under the proposed rule, equation G–4 and equation G–5 would be combined into a new equation G–4 and paragraph 98.73(b)(5) would be deleted. The reporting requirement in paragraph 98.76(b)(1) specifies emissions for each individual ammonia manufacturing processing unit, so determining the combined CO_2 emissions from all ammonia manufacturing processing units using equation G–5 is not necessary for reporting. The new equation G–4 would allow reporters to subtract CO_2 used in the production of urea and carbon bound in methanol that is intentionally produced as a desired product instead of assuming that the CO_2 bound in urea is emitted or that the carbon contained in methanol is converted to CO_2 and emitted, resulting in the calculation of net CO_2 emissions that occur directly from ammonia manufacturing. We are also proposing a harmonizing revision to the introductory paragraph of 40 CFR 98.73. These proposed changes are not expected to result in an increase in burden because the monthly equation inputs for the new equation G–4 would already be available to calculate the annual values of CO_2 collected from ammonia production and consumed on-site for urea production and the quantity of intentionally produced methanol, both of which are already reported. Similarly, for reporters that do not produce urea or methanol, the burden under the new equation to calculate CO_2 emissions remains unchanged. Further, because we are retaining the requirement to report the CO_2 collected from ammonia for urea production and methanol production, the proposed amendments would not result in any negative impacts to the quality of the data collected under the GHGRP and such data would remain available for potential policy evaluation.

As a result of the new proposed equation G–4, two new monthly recordkeeping data elements are being proposed as part of the verification software records required in 40 CFR 98.77(c), including: (1) quantity of CO_2 collected from ammonia production and consumed on site for urea production each month; and (2) quantity of methanol intentionally produced as a desired product each month. These recordkeeping changes are not expected to result in a significant increase in burden because both elements are already being reported on an annual basis (40 CFR 98.76(b)(13) and (15)). For reporters that do not produce urea or methanol, the requirements for recordkeeping remain unchanged. We are proposing harmonizing revisions to the introductory paragraph of 40 CFR 98.76 and to the reported data elements at 40 CFR 98.76(b)(1) to clarify that reporters must provide the ''annual net CO_2 process emissions'' for each ammonia manufacturing unit, and at 40 CFR 98.76(b)(13) to clarify that reports must provide the ''annual amount of CO_2 collected from ammonia production (metric tons) and consumed on site for urea production and the method used to determine the CO_2 consumed in urea production.'' The proposed revision to the reported emissions value excludes any CO_2 used in the production of urea and carbon bound in methanol that is intentionally produced as a desired product. We are proposing related confidentiality determinations for the revised data elements, as discussed in section VI of this preamble.

Finally, corresponding amendments are being proposed to remove the language specified above that was added in the 2010 Final Revisions Rule (75 FR 79092), described above. Paragraph 98.72(a) will be amended to read, ''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.''

In addition, minor amendments to equation G–1, equation G–2, and equation G–3 are being proposed to simplify the equations by removing the process unit ''k'' designation in the terms ''$CO_{2,G,k}$,'' ''$CO_{2,L,k}$,'' and ''$CO_{2,S,k}$.'' The introductory paragraph to each of these equations already specifies that emissions must be calculated for each ammonia manufacturing unit. Removing the extra subscript will

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EPA–HQ–OAR–2012–0934–0127, November 2013. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[20] TFI's Comments on the Proposed ''*2015 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule,*'' Docket Id. No. EPA–HQ–OAR–2015–0526–0064, March 30, 2016. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[21] TFI, *Impact of Federal Regulations on Domestic Manufacturing,* Docket Id. No. DOC–2017–0001–0064, March 31, 2017, available in *Compilation of Comments Related to the Greenhouse Gas Reporting Program submitted to the Department of Commerce under Docket ID No. DOC–2017–0001 and the Environmental Protection Agency under Docket ID No. EPA–HQ–OA–2017–0190* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[22] TFI, *Comments on ''Evaluation of Existing Regulations,''* Docket Id. No. EPA–HQ–OA–2017–0190–40791, May 15, 2017, available in *Compilation of Comments Related to the Greenhouse Gas Reporting Program submitted to the Department of Commerce under Docket ID No. DOC–2017–0001 and the Environmental Protection Agency under Docket ID No. EPA–HQ–OA–2017–0190* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

clarify the equations. No changes to burden are expected from these changes.

D. Subpart H—Cement Production

For the reasons described in section II.A.4 of this preamble, we are proposing to add new data elements to the data reporting requirements for subpart H of part 98 (Cement Production) to enhance the quality and accuracy of the data collected. Specifically, we are proposing to collect new data elements under 40 CFR 98.86(a) and 40 CFR 98.86(b). Subpart H currently requires calculation of CO_2 emissions using one of two methodologies, either direct measurement using CEMS, or a mass balance (non-CEMS) methodology based on mass, carbonate content, and fraction of calcination for each carbonate-based material. For the mass balance method, facilities enter input data that is used to calculate emissions factors for produced materials. These inputs include, for example, monthly measurements of calcium oxide content and magnesium oxide content. Subpart H emission equations inputs are not collected under the GHGRP, and so the EPA has little data on which to build verification checks for these inputs in the reporting system. In order to improve the data verification process, we are proposing to collect annual averages for these chemical composition input data on a facility-basis. The proposed data elements (for both facilities that report CEMS data and those that report using a mass-balance method) include the annual arithmetic average weight fraction of: total CaO content, non-calcined CaO content, total MgO content, and non-calcined MgO content of clinker at the facility; and 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. The proposed data elements would rely on an arithmetic average of the measurements rather than requiring reporters to weigh by quantity produced in each month. CEMS facility emissions calculations are importantly different from non-CEMS emissions calculations because combustion and process emissions are typically vented through the same stack, causing process and combustion emissions to be mixed and indifferentiable. Therefore, in addition to improving the input verification process, collecting average chemical composition data for CEMS facilities will provide the EPA the ability to check the reported CEMS emission data for accuracy by creating the ability to back-estimate process emissions. In order to be able to estimate and check the accuracy of process emissions, we are also proposing to collect other data elements for 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 and raw kiln feed consumed annually at the facility in tons (dry basis). Facilities are already required to report or maintain records of other production data that would be needed to perform these estimates. Facilities using the mass-balance method currently collect CKD not recycled to the kiln(s) on a quarterly basis to estimate CO_2 emissions from clinker production. Similarly, facilities also record the annual raw kiln feed for each kiln, which is used to determine the CO_2 emissions from raw materials for each kiln in equation H–5. The proposed data elements would instead sum the CKD not recycled and raw kiln feed quantity across all kilns at a facility. The proposed data elements will allow us to estimate process emissions for comparison to facility reported emissions estimates as a verification check. In addition to improving verification and data quality for cement emissions, the proposed data elements will also improve the U.S. GHG Inventory. The U.S. GHG Inventory can use the proposed data elements to internally disaggregate process and combustion emissions that are reported by facilities using CEMS, and create more accurate national-level cement emissions profile.

In general, we do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as these data are likely already available in existing company records. These additions would result in especially minimal reporting changes for non-CEMS facilities, as the chemical composition averages can be calculated using the input data that is already required to be entered in the reporting system. However, we are requesting comment on whether any of the above listed data elements would not be readily available to reporters. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

Finally, for the reasons described in section II.A.5 of this preamble, we are proposing to clarify equations H–1 and H–5. We are proposing to clarify that equation H–5 calculates the CO_2 emissions from raw materials on a per kiln basis. Facilities currently maintain records of the amount and organic carbon content of raw materials and raw kiln feed consumed annually per kiln, and enter this data into the e-GGRT verification software during submission of their annual reports. The verification software collects the kiln-level data to verify the inputs and generates a file containing the records, which are specified in 40 CFR 98.87(c)(14) through (17). The CO_2 emissions for the facility are then summed for all kilns at the facility-level using equation H–1, which sums the annual CO_2 emissions from clinker production (from equation H–2) and the annual emissions from raw materials for each kiln (from equation H–5). We are proposing revisions to the inputs ‘‘rm,’’ ‘‘$CO_{2\ rm,}$’’ and ‘‘TOC_{rm}’’ in equation H–5 to clarify that the data elements are input on a per-kiln basis, and to 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. Similarly, we are proposing to revise equation H–1 to add brackets to clarify the summation of clinker and raw material emissions for each kiln, and updating the definition of ‘‘$CO_{2\ rm}$’’ to clarify the raw material input is on a per-kiln basis. The proposed revisions are corrections that would harmonize equations H–1 and H–5 with the existing recordkeeping requirements and align the calculation methodology in the rule and e-GGRT. We are also proposing minor corrections to the parameters of equation H–4 for quarterly non-calcined CaO content of CKD not recycled to the kiln and quarterly non-calcined MgO content of CKD not recycled to the kiln. The 2009 final rule inadvertently defined the equation parameters for both quarterly non-calcined CaO content and quarterly non-calcined MgO content as ‘‘CKD_{CaO}’’ and ‘‘CKD_{MgO}’’, respectively, while equation H–4 defines these parameters as ‘‘CKD_{ncCaO}’’ and ‘‘CKD_{ncMgO}’’. To remove any confusion for reporters, we are proposing to correct the defined parameters for quarterly non-calcined CaO content and quarterly non-calcined MgO content of CKD not recycled to ‘‘CKD_{ncCaO}’’ and ‘‘CKD_{ncMgO}’’, respectively. These clarifications would not require any changes to the monitoring, recordkeeping, or reporting provisions, or impact how reporters currently collect or enter data for their annual reports.

E. Subpart I—Electronics Manufacturing

Under subpart I of part 98 (Electronics Manufacturing), electronics manufacturing facilities must report F–GHG and F–HTF emissions from electronic manufacturing production processes and N_2O emissions from chemical vapor deposition (CVD) and other electronics manufacturing processes. Facilities must also report CO_2, CH_4, and N_2O emissions from each stationary combustion unit by following the requirements of subpart C (General Stationary Combustion Sources).

We are proposing several amendments and clarifications to the calculation methodologies requirements in subpart I. In addition, the EPA is proposing conforming changes to the reporting and recordkeeping requirements of subpart I. Changes include updating existing default emission factors and destruction or removal efficiencies (DREs) based on new data, revising certain calculation methods, adding a calculation method for calculating by-products produced in abatement systems, amending data reporting requirements, and providing clarification on reporting requirements. We are proposing revisions that will better reflect new industry data and current practice, improve the quality of the data collected, and streamline the reporting requirements. We are also proposing related confidentiality determinations for the proposed new or revised data elements, as discussed in section VI of this preamble.

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

a. Revisions To Improve the Calculation Methodology for Stack Testing

We are proposing to revise 40 CFR 98.93(i), which specifies how to calculate GHG emissions based on stack testing, in order to improve, simplify, and correct the calculation method. As discussed in section II.A.2 of this preamble, the proposed edits would improve the quality of the data collection and calculation requirements associated with stack testing. First, we are proposing to add 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 by-products exhausted from tools with abatement systems, $a_{k,i,f}$, for use in equations I–20 and I–22. Second, we are proposing to revise equations I–24A and I–24B, which calculate the weighted average DREs for individual F–GHGs across process types in each fab.[23] Third, we are proposing at 40 CFR 98.93(i)(3) to require that all stacks be tested if the stack test method is used. Finally, we are proposing to replace 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.

The first three changes to the stack test method would remove the 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. Currently, the fractions of fluorinated input gases and by-product gases exhausted from manufacturing tools with abatement systems, used in equations 1–19a through I–22, must be estimated by apportioning gas consumption to these tools. The proposed equations I–24C and I–24D would add the option to calculate the fraction of each input gas ''i'' and by-product 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 different per-tool emission rates that apply to different process types. Facilities would continue to have the option to apportion gas consumption to tools with and without abatement systems by using paragraph 98.93(e). They would also have the option to apportion gas consumption to the different process types and sub-types, calculating $a_{i,f}$ and $a_{k,i,f}$ based on the numbers of tools with and without abatement systems within each process type or sub-type.

Weighting factors are necessary when: (1) per-tool pre-control emission rates differ between different process types; (2) an input gas is consumed by more than one process type; (3) the use of the input gas is not apportioned between the process types; and (4) the fractions of tools equipped with emissions control technologies differ between process types. The weighting factors ($\gamma_{i,p}$ for input gases and $\gamma_{k,i,p}$ for by-product gases, provided in Table I–18) are based on data submitted by semiconductor manufacturers during the process of developing the *2019 Refinement.*[24] This data source was used in lieu of subpart I data, as the EPA does not collect data on gas consumption or gas consumption per tool. The calculated weighting factors were within the expected range, considering the differences between the emission factors used and the expected per-tool gas consumption for the different process types. For microelectromechanical systems (MEMS) or PV manufacturing that uses semiconductor tools and processes, the weighting factors in Table I–18 can be used. For processes without a weighting factor in Table I–18, a default of 10 must be used. More information on the data used to develop the weighting factors in Table I–18 can be found in the document, *Technical Support for Proposed Revisions to Subpart I (2021)* (hereafter referred to as ''subpart I TSD''), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

Equations I–24A and I–24B, which calculate the weighted average DREs for individual F–GHGs across process types, would rarely be used if the EPA adopts the same default DREs for all process types as discussed in section III.E.1.b of this preamble, because there will rarely be any need to calculate weighted average DREs across process types in that case. The sole exception may occur when 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. To accommodate this situation and to simplify equations I–24A and I–24B, we are proposing to modify equations I–24A and I–24B to calculate the average DRE for each input gas ''i'' and by-product gas ''k'' based on tool counts and the same weighting factors that would be used in equations I–24C and I–24D. This would eliminate the requirement to apportion gas consumption by process type when using the stack test method, even for those facilities that use abatement systems with different DREs for the same input gas ''i'' or by-product gas ''k''.

Requiring that all stacks be tested (if the stack test method is used) would remove not only the need to apportion gas usage to tested versus untested stacks, but also the requirement to perform a preliminary calculation of the emissions from each stack system (we are proposing to remove the requirements at 40 CFR 98.93(i)(1)). The EPA expects that the data received would be more accurate due to requiring testing of all stacks. The EPA also expects that the revision to measure all stacks instead of apportioning gas usage between process type and subtype and between tested and untested stacks would streamline the implementation of the stack testing method at facilities and increase the likelihood of this method being used instead of the emission factor approach. Currently, to account

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[23] Fab is defined in 40 CFR 98.98 as ''the portion of an electronics manufacturing facility located in a separate physical structure that began manufacturing on a certain date.''

[24] The data used to develop the gamma weighting factors are also available in the IPCC workbook, ''Gamma Data Submitted by Industry.xlsx,'' (2019), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

for emissions from untested stacks, facilities must calculate gas consumption of each F–GHG used in tools that are vented from untested stacks by apportioning gas between untested and tested stacks. When abatement is used, facilities also currently need to apportion by process type. Apportioning gas requires using a fab-specific engineering model that must be based on a quantifiable metric, such as wafer passes or wafer starts, or direct measurement of input gas consumption and must be verified by demonstrating its precision and accuracy as described in 40 CFR 98.94(c)(1). As the number of stacks at each fab is expected to be small (*e.g.,* one to two), the EPA expects that measuring all stacks would be more accurate and less burdensome than developing and verifying an apportioning model.

We also seek comment on whether stack testing should also be used to estimate N_2O emissions if stack testing is the calculation method elected. Currently, the stack testing option in subpart I is limited to estimating emissions from F–GHGs; N_2O emissions must be estimated using the default emission factors in Table I–8. The use of the stack testing method for N_2O was not previously recommended by industry due to: (1) the high monthly and yearly variability in measured N_2O emission factors estimated from stack testing for some fabs; and (2) the observation that estimated N_2O emission factors from stack testing also often exceeded 1, indicating a second, unidentified, source of N_2O.[25] No source for the additional N_2O formation or the high variability was identified. The EPA requests comment on the extent to which the sources of N_2O formation from electronics manufacturing have been identified. We are also requesting comment on the expected variability of the estimated N_2O emission factor from stack testing if using the current or revised methods for estimating emissions using stack testing and whether new data are available. If estimated N_2O emission factors are now expected to be consistent over time, the use of N_2O in stack testing could be re-evaluated during a future rulemaking.

We are also proposing to replace equation I–19 with a set of equations that will more accurately account for by-product emissions when that by-product F–GHG is also an input gas. Specifically, the new equations 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. Pre-control emissions of an F–GHG can approach or exceed consumption of that F–GHG when the F–GHG is generated as a by-product of other F–GHGs used in the fab. To ensure that calculated emission factors reflect this physical reality, any excess pre-control emissions of the F–GHG should be assumed to be formed as a by-product. Currently, the paragraph containing equation I–19, 40 CFR 98.93(i)(3)(iii), does not sufficiently account for such by-product formation, potentially resulting in overestimated input gas emission factors and underestimated by-product gas emission factors.

This potential inaccuracy arises because 40 CFR 98.93(i)(3)(iii), in its assignment of portions of the emissions to either input gases or by-products, does not currently account for the utilization (dissociation) of the input gas or for any abatement of the input gas. Instead, the provision compares the total measured emissions of the F–GHG, which may have passed through abatement systems prior to measurement, to the consumption (termed ''activity'' in equation I–19) of that F–GHG during the stack testing period. If the measured emissions equal or exceed consumption, the term for total emissions in equation I–19, $\mathbf{\Sigma}_s E_{i,s}$, is equated to consumption to calculate the input gas emission factor, and any difference between the measured emissions of the F–GHG and the consumption of the F–GHG is treated as by-product emissions and used to calculate a by-product emission factor (BEF) in equation I–20. While this approach avoids assigning a controlled emission factor greater than 1.0 to the input gas, in cases where the measured emissions are greater than consumption, the corresponding pre-control emission factor is either equal to 1.0 (if the measured emissions are uncontrolled) or greater than 1.0 (if the measured emissions are controlled). In the first case, the pre-control emission factor fails to account for any utilization of the input gas. In the second case, the pre-control emission factor both fails to account for any utilization of the input gas and attributes emissions to the input gas for which the input gas cannot possibly be the source (because that would violate conservation of mass).

To more accurately assign emissions of the gas to by-product or input gas emissions, a better methodology is to compare the measured emissions to the maximum expected controlled emissions of the input gas during the stack testing period, rather than to the consumption during that period. To make this change, we are proposing to remove equation I–19 and replace that equation with equations I–19A, I–19B, and I–19C, making corresponding changes to 40 CFR 98.93(i)(3)(iii). Equation I–19A estimates the maximum expected controlled emissions for each F–GHG from the fab during the stack testing period at a utilization rate (U) equal to 0.2 (*i.e.,* a 1–U or input gas emission factor of 0.8) and at the levels of abatement and abatement system uptime observed during the stack testing period. If the total emissions measured during the stack testing period are less than the maximum expected controlled emissions calculated using I–19A, then all emissions of gas i are attributed to the consumption of gas ''i'' and equation I–19B is used to calculate the input gas emission factor for gas ''i''. Equation I–19B is similar to equation I–19 in the current rule, but with an updated process-independent variable for the DRE. However, if the total measured emissions are greater than the estimate of the maximum controlled emissions, then the input gas emission factor is assumed to be equal to the maximum controlled emission rate at an uptime equal to 1, as calculated in equation I–19C. The remaining emissions (the difference between the measured emissions and the value calculated in equation I–19A) are used to calculate the BEF for that gas from other input gases in equation I–20.

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. The input gas emission factor (1–U) of 0.8 used in equations I–19A and I–19C is the same as the default 1–U factor that would be assigned where a default is not available in Tables I–3 and I–4, as discussed in III.E.2.b of this preamble. Using a value of 0.8 as a maximum input gas emission factor (1–U) would be consistent with the other proposed changes and is expected to increase the accuracy of the stack testing method, as some utilization of the input gas is expected. These changes to the stack testing equations would improve the quality of the stack testing method by more accurately assigning emissions to their source.

In addition to the substantive changes to equation I–19, the EPA is proposing to clarify the definitions of the variables

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[25] See Semiconductor Industry Association (SIA) *Response to EPA's Stack Test Question 1,* March 7, 2012, and *Technical Support for Other Technical Issues Addressed in Revisions to Subpart I,* U.S. EPA, August 2012, both of which are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

d_{if} and d_{kif}, the average DREs for input gases and by-product 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 of subpart I. Currently, the definition for the variable d_{if} reads ‘‘Fraction of fluorinated GHG input gas i destroyed or removed in abatement systems connected to process tools in fab f,’’ which could be interpreted to reflect both the fraction of emissions of gas i that is fed into abatement systems and the fraction of gas i that is destroyed once gas i is fed into abatement systems. However, d_{if} (and d_{kif}) are only intended to reflect the fraction of gas i (or by-product gas k) that is destroyed once gas i (or by-product gas k) is fed into abatement systems. To make this clear, we are proposing to change the definition of d_{if} to read ‘‘Fraction of fluorinated GHG input gas i destroyed or removed when fed into abatement systems by process tools in fab f,’’ and we are proposing a parallel change to the definition of d_{kif}.

b. Revisions To Clarify and Revise Calculation Methodologies and Required Data Elements for Data Submitted in the Technology Assessment Report

For the reasons described in section II.A.1 of this preamble, we are proposing to require that three emission factor calculation methods, specified in this section and described in the subpart I TSD (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424), be used when calculating utilization and by-product emission rates submitted in technology assessment reports. These three methods would be used to report the results of each emissions test. Based on a comparison among the results of the three methods, we may ultimately require use of a single method through a future rulemaking.

As stated in the preamble to the 2013 final rule that established the requirement to submit technology assessment reports (78 FR 68175, November 13, 2013), one of the EPA's goals in collecting emission factor data through the reports 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 the same way as the emission factors already in the EPA's database were calculated; otherwise, differences attributable to differences in calculation methods may amplify or obscure differences attributable to technology changes. To date, the EPA has not initiated a broad data collection to comprehensively update the default emission factors, but the EPA is now proposing to use the emission factor data submitted in the 2017 and 2020 technology assessment reports to make minor updates to the default emission factors, and the EPA may continue this practice in the future. This introduces a second goal for the emission factors submitted in the technology assessment report, which is that they be robust to ensure that the resulting updated default emission factors are robust. To meet this goal, the reported emission factors should be broadly applicable because they reflect physical reality as much as possible and are not unduly affected by changing proportions of input gases. In addition, the reported emission factors should be consistently calculated across facilities and processes to ensure that the resulting defaults are not biased by ‘‘cherry-picking’’ of methods to achieve a desired result for a given process or facility (or set of processes or facilities). Requiring facilities to (1) use specified methods to calculate emission factors and (2) use all three methods for each test meets these goals to different extents and in different ways.

Requiring facilities to use specified emission factor calculation methods would ensure that the emission factors are robust insofar as the calculation methods are designed to yield robust factors. It would also help ensure that the emission factors are developed in a reasonably, though not perfectly, consistent manner across processes and facilities and over time, given that the proposed calculation methods are similar but not identical. (As discussed in this section, two of the proposed emission factor calculation methods are based closely on the emission factor calculation methods used for the emission factors already in the EPA's database.) The EPA has previously received emission factors calculated via a variety of methods, as described further in this section. This has sometimes made it difficult to determine whether changes in calculated emission factors are due to changes in technology or to changes in the emission factor calculation method. In some cases, we have not been able to use submitted emission factor data because it was found to be calculated using a method that was significantly different from previous methods and that appeared unlikely to represent actual gas behavior. (The lead authors of the Electronics chapter of the *2019 Refinement* declined to use this data for similar reasons.)[26] Specifying emission factor calculation methods would at least partially address these problems.

Requiring facilities to submit three sets of emission factors for each test would more fully address these problems by enabling us: (1) to directly compare the new emission factor data to the emission factor data that is already in the EPA's database and that was calculated using the same 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 would be better able to distinguish these differences from differences attributable to technology changes. This would enable us to build a bridge between the data sets resulting from the different methods, which would be useful in the event that we ultimately required facilities to submit emission factors using one method only, particularly if that method was not one of the methods used historically. We would also be able to evaluate how much the results of each method varied 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, as discussed further in this section. Ultimately, these analyses would 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. Because we plan to incorporate the three methods into spreadsheets that would calculate three sets of emission factors based on a single set of entered data, we do not anticipate that requiring reporting of the results of the three methods would significantly increase burden. We are proposing the three emission factor calculation methods in 40 CFR 98.96(y)(2)(iv)(A) through (C).

Two of the proposed methods are closely based on the methods that have been used historically to calculate emission factors for processes that use multiple gases: ‘‘all-input gas method’’

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[26] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

and the ''dominant gas method''.[27] [28] Consequently, the emission factors calculated using these methods are generally expected to be comparable to the emission factors calculated and submitted to the EPA in the past. The emission factors calculated using these methods are also expected to be reasonably robust except under certain circumstances discussed further in this section. To increase the robustness of the emission factors calculated using these methods under those circumstances, we are proposing to modify the methods to avoid input gas emission factors greater than 0.8 for processes that use multiple gases.

Historically, both the all-input gas and dominant gas methods have calculated the input gas emission rate in the same way: all emissions of each F–GHG that is an input gas have been attributed to the 1–U factor for that gas (kg of input gas emitted/kg of input gas used); that is, both methods imply that if an F–GHG is used as an input gas, that F–GHG is *not* also formed as a by-product. However, the two methods treat by-product F–GHGs that are not used as input gases differently. The dominant gas convention assigns all emissions of F–GHG by-products to the carbon-containing F–GHG input gas accounting for the largest share by mass of the input gases (kg of by-product emitted/kg of dominant gas used), while the all-input gas convention assigns emissions of F–GHG by-products to all F–GHG input gases (kg of by-product emitted/kg of all F–GHGs used). With a slight modification, the all-input convention has also been used to assign emissions of F–GHG by-products to only all carbon-containing F–GHG input gases, *i.e.,* not to SF_6 or NF_3 input gases (kg of by-product emitted/kg of all F–GHGs used).

Due to the complex set of chemical reactions necessary to describe plasma etching by multiple input gas processes, it is not generally known what fractions of a by-product gas are produced by each input gases, or what fractions of an emitted input gas consist of unreacted residual gas versus newly formed by-products of other gases. Both methods of assigning emission factors described above have historically been based on the assumption that the emissions of each input gas (1–U) are much larger than the emissions of the same gas as a by-product of the other input gases (*e.g.,* CF_4 produced from C_2F_6) and thus, the BEF can be approximated as zero. However, as stated in section III.E.1.c of this preamble on updates to the default emission factors, it has been well established that most input gases produce CF_4 and C_2F_6 in significant quantities. Thus, in cases where C_2F_6 or CF_4 is an input gas (and possibly for some additional cases), assigning all of the emissions of C_2F_6 or CF_4 to the C_2F_6 or CF_4 input gas, respectively, may not be a good approximation and can lead to cases where the reported emission factor is greater than 1, which violates conservation of mass. This is most likely to happen when an input gas such as CF_4 makes up a relatively small share of the total input gas mass and is also generated in significant quantities as a by-product by the other input gases.

To address this issue, our proposed methods include a modification to both of the historically recommended methods to avoid an input gas emission factor greater than 0.8 when multiple gases are used, and we are also proposing to introduce an additional calculation method. The modified methods would attribute emissions of each F–GHG used as an input gas to that input gas until the mass emitted equaled 80 percent of the mass fed into the process, that is, until the 1–U factor equaled 0.8. The methods would then assign the remaining emissions of the F–GHG either to the dominant input gas as a by-product (in the dominant gas method) or to the other input gases as a by-product in proportion to the quantity of each input gas used in the process (in the all-input gas method). This approach avoids violating conservation of mass and better reflects the expectation that at least a small portion of the input gas will be utilized in the process. Nevertheless, because 0.8 represents an upper bound for input gas emission factors, even the modified methods have the potential to significantly overestimate input gas emission factors. To the extent that these factors are later applied to processes where the input gas accounts for a larger share of the total input gas mass (*e.g.,* because they are used to calculate default factors), they will overestimate emissions of the input gas.

A third convention, the reference emission factor method, is likely to provide more robust, realistic results, although it represents a somewhat larger change from the emission factor calculation conventions historically used. The reference emission factor method begins with the average input gas utilizations (1–U factors) and/or BEFs observed based on single gas recipes. In single-gas recipes, all emissions of an input gas clearly originate from its use as an input gas, and all emissions of a by-product clearly originate from its generation as a by-product; thus, the 1–U factor and BEFs based on single-gas recipes are not affected by the uncertainties regarding the origins of the emissions that can affect these factors for multi-gas recipes.

Since it is not known whether the 1–U factor or BEFs are more likely to change in moving from single- to multiple-gas recipes, the reference emission factor method calculates emissions using the 1–U and the BEFs 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.

In summary, the chief advantage of the dominant gas method proposed at 40 CFR 98.96(y)(2)(iv)(A) and the all-input gas method proposed at 40 CFR 98.96(y)(2)(iv)(B) is that they are the methods used previously to calculate the emission factors that are already in the EPA's database and that form the basis of the current subpart I default 1–U and BEFs. Therefore, new emission factors calculated using these methods are expected to be comparable[29] to the emission factors already in the EPA's database, facilitating efforts to identify changes in emission factors that are attributable to technology changes. The chief disadvantage of these two methods is that they can result in a significantly overestimated 1–U value when the share of an input gas such as CF_4 declines.

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[27] See section 2.0 of the document, *Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I* (2012), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[28] Previously, the EPA had suggested that the all-input gas method be used for etch emission factors (*Ibid.*), and most of the etch data in the data set used to develop the current emission factors used this method (see 78 FR 68185 and previously submitted data sets *Etch Process Equipment Emissions Characterization Data* and *International SEMATECH Manufacturing Initiative Environmental Safety and Health Technology Center,* February 2012, and the document *Draft Emission Factors for Refined Semiconductor Manufacturing Process Categories* (2010), all available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). However, some of this data was calculated using the dominant gas method.

[29] As discussed further in the document Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I, cited above in this section, trends in gas usage, such as the use of more and more individual input gases, may introduce apparent, but not real, trends in the 1–U values calculated using these methods.

This disadvantage is mitigated partly, but not completely, by capping 1–U values at 0.8. At the same time, however, capping 1–U values at 0.8 decreases the comparability of these methods with those previously used to calculate and report emission factors. The EPA requests comment on whether the gain in robustness achieved by capping 1–U values at 0.8 justifies the accompanying loss in comparability to previously submitted data, particularly given that we are proposing to require submission of results using both the historically used methods and the new, likely more robust, reference emission factor method. The reference emission factor method is being proposed at 40 CFR 98.96(y)(2)(iv)(C). The advantages and disadvantages of the three methods are described further in the document *Technical Support for Modifications to the Fluorinated Greenhouse Gas Emission Estimation Method Option for Semiconductor Facilities under Subpart I,* cited above in this section. The EPA also considered requiring use of one specific method for the data submitted in future technology assessment reports. This would allow all future reports to have comparable data. However, if one of the historically used methods were specified, the resulting emission factors might not be as robust as they would be if the reference emission factor method were specified. On the other hand, if the reference emission factor method were specified, the resulting emission factors would not be fully consistent with previously submitted emission factors, and this inconsistency would be difficult to address without having seen the results of the different methods side-by-side at least once. Another option would be to let the reporter choose one of three methods in 40 CFR 98.96(y)(2)(iv)(A) through (C) for subsequent reports. This option would result in a loss of comparability between tests. The EPA is requesting comment on these alternatives.

We request comment on the methods proposed at 40 CFR 98.96(y)(2)(iv)(A) through (C) for calculating emission factors for multi-gas recipes, particularly concerning their reliability as indicators of actual emission rates and emission rate trends. In addition, the EPA requests comment on the use of 0.8 as the maximum 1–U value in the modified dominant-gas and all-input gas methods.

We also request comment on the reference emission factor method proposed at 40 CFR 98.96(y)(2)(iv)(C). While this method differs from the historically used methods, the differences are not expected to become important except where CF_4 or C_2F_6 make up a small share of the input gas mass, that is, where the historically used methods are known to yield inaccurate results. The EPA believes that the increase in accuracy gained through the new method justifies some loss of time series consistency (*i.e.,* comparability between newly submitted emission factor data and previously submitted emission factor data). Moreover, because we are proposing to require reporting of the results of each test using all three calculation methods, we can compensate for the loss of time series consistency between the historically used methods and the reference emission factor method by: (1) comparing the emission factors already in the EPA's database to the versions of the new emission factors calculated using the historically used methods (*i.e.,* the all-input gas and dominant gas methods); and (2) analyzing systematic differences that occur between the results of the historically used methods and of the reference emission factor method so that these can be considered in future comparisons between new and existing data. We also request comment on whether BEFs based on multi-gas recipes should be included in the reference BEFs for the reference emission factor method. The benefit of including BEFs based on multi-gas recipes in the reference BEFs is that this would increase the number of data points used as a basis for those BEFs, in some cases providing reference BEFs where none are available from the single gas data set (due to a lack of data). The drawback of including BEFs based on multi-gas recipes is that these BEFs are subject to some uncertainty. BEFs measured for multi-gas recipes where the by-product F–GHG is not also used as an input gas are less uncertain than BEFs where the by-product F–GHG is also an input gas. However, uncertainty remains regarding which of the multiple input gases are primarily responsible for the formation of that by-product and whether all input gases contribute to the formation of each by-product. For more information on the advantages and disadvantages of using only single-gas measurements or all measurement to determine reference emission factors see the subpart I TSD, cited above in this section.

We also seek comment on whether there are alternative methods for calculating utilization and by-product formation rates that the EPA should consider in the future. To enable us to evaluate any suggested methods, we request that commenters suggesting an alternative method also provide information on the rationale for using the alternative method instead of one of the methods described above and a comparison between a representative group of emission factors (both 1–U and BEFs) calculated using the alternative method and a group of emission factors based on the same data but calculated using the all-input gas method, the dominant gas method, and the reference emission factor method. The EPA may evaluate, at a future date, such alternative methods based, for example, on the likely accuracy of the alternative calculation method and its consistency with previously used calculation methods.[30]

We are also proposing that where reporters provide any data on utilization and by-product formation rates in the technology assessment report, they must also specify the method used to calculate the reported utilization and by-product formation rates and assign and provide an identifying record number for each data set. This information allows the EPA to better understand the data being submitted. For example, this information helps the EPA identify all the gases used in a multi-gas test and understand the influence of the calculation method and gas mixtures on the resulting emission factors. This detailed understanding may help us to develop new or revised emission factors that are representative of the industry. Without collecting these data, the EPA may not be able to effectively evaluate the influence of different emission factor calculation methods or gas combinations on the resulting emission factors.

We are also proposing at 40 CFR 98.96(y)(2)(iv) that for any destruction or removal efficiency (DRE) data submitted, the report must include whether the abatement system used for the measurement is specifically designed to abate the gas measured under the operating condition used for the measurement. This information will help the EPA understand whether the submitted data should be considered to be a result for a certified abatement system for the gas being measured. The efficacy of abatement systems generally depends on both whether it is designed to abate the F–GHG and whether it is installed, operated, and maintained according to the manufacturer's specifications. Abatement systems are known to have reduced efficacy when the individual process gas and total gas flow rates (including any added purge

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[30] See document *Technical Support for Proposed Revisions to Subpart I (2021),* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

gases) as specified by the abatement system supplier are exceeded.

c. Updates to Default Emission Factors and Destruction or Removal Efficiencies To Improve the Accuracy of Emissions Estimates

The EPA is proposing to update the default emission factors and destruction or removal efficiencies (DREs) in subpart I based on new data submitted as part of the 2017 technology assessment report (submitted with the RY2016 annual report) and the 2020 technology assessment report (submitted with the RY2019 annual report).[31] First, we are proposing to update the utilization rates and BEFs for F–GHGs used in semiconductor manufacturing in Tables I–3, I–4, I–11 and I–12 to reflect new data received in the 2017 and 2020 technology assessment reports, to correct errors identified in the data set on which the current default emission factors are based, and to remove BEFs where both the emission factor and the GWP of the emitted by-product are very low. Second, we are also proposing to update and expand the default emission factors for N_2O used in all electronics manufacturing in Table I–8 based on both new data from the 2017 and 2020 technology assessment reports and new emission factors available in the *2019 Refinement.* Third, we are proposing at 40 CFR 98.93(a)(6) to revise the utilization rate and BEF values assigned to gas/process combinations where no default utilization rate is available. Finally, we are proposing to update the default DREs in Table I–16 to reflect the incorporation of new data from the 2017 and 2020 technology assessment reports and a new approach to abatement system certification. These updates are expected to increase the accuracy of the emissions reported by facilities under subpart I.

The proposed emission factors for Tables I–3, I–4, I–11, and I–12 were calculated from measured data submitted by U.S. semiconductor manufacturers as part of the 2020 technology assessment report, 2017 technology assessment report, and data collected in previous years.[32] The total data set contains 4,358 input gas and BEFs across all commonly used gas and process type combinations, with 1,506 of these data points newly available via the 2020 and 2017 triennial technology assessment report. All the data submitted via the 2020 and 2017 triennial technology assessment report were applicable to the 300-mm wafer size. All data sets were reviewed for errors, including, but not limited to, transcription errors and violations of the fluorine balance. Calculated emission factors (1–U or BEFs) greater than 1.00 (a total of 18 data points) were excluded from the calculation of the proposed default emission factors (EFs). Input gas and by-product gas emission factors were also analyzed for each test to see whether the fluorine balance was violated. This resulted in the exclusion of 40 data points from the calculation of the proposed default emission factors. There were also a small number of transcription or other errors, including duplicate rows of data, that were corrected or excluded prior to calculating the proposed emission factors. Transcription and other errors resulted in the exclusion of 33 data points. A single reported by-product value for SF_6 was also excluded from the calculation, as there was no source of sulfur. Four emission factors for NF_3 in remote plasma cleaning (RPC) processes that were previously excluded[33] were re-included in the data set, as discussed in the subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

Submitted data were also reviewed for methodological consistency with previously submitted data. As discussed earlier in III.E.1.b of the preamble, data submitted to the EPA prior to 2017 used either the dominant gas or all-input gas convention. However, many of the data points for etching submitted as part of the 2020 and 2017 technology assessment report used an alternative convention that had not been previously used. This new ''multi-gas'' convention differed in how it assigned emissions of input gases. Instead of assigning measured emissions of an input gas entirely to the input gas, emissions of an input gas were assigned to all input F–GHGs used in the process by dividing the measured mass emitted of a specific input gas by the total mass of all input F–GHGs and assigning this emission factor to each input F–GHG as either the 1–U factor or the by-product factor, *i.e.,* all input F–GHGs were considered to equally contribute to the emissions of each input gas. This method was inconsistent with the methods of the previous data set, and the alternative method often resulted in large increases to the reported BEFs and concurrently large decreases to the reported 1–U. This change appeared to be largely a result of the change in methodology; however, it was not possible, based on the data received, to fully assess the effect of the new methodology as the data were not directly comparable to previously submitted data. The data points that were affected by the change in convention were excluded from the calculation of the proposed default EFs, resulting in the exclusion of 338 data points. This left a total of 3,951 data points in the combined data set that were included in the calculations of the proposed default emission factors in Tables I–3 and I–4.

The proposed default EFs for Tables I–3 and I–4 were calculated using a simple arithmetic mean of all EF data that used either the all-input gas or the dominant gas convention. The technology assessment reports reported no major changes to semiconductor production technology, and the differences between the average emission rates calculated based on the new and previously submitted data, respectively, are generally small (*i.e.,* less than ± 20 percent for most commonly used input gases). Therefore, it is assumed in most cases that the proposed default emission factors for F–GHGs reflect increased and/or improved data rather than changes in actual emission or utilization rates. This means that for each wafer size (<200 mm and 300 mm), the proposed emission factors are generally likely to represent emission rates over all the years of the GHGRP. However, for a few gas and process type combinations for the 300-mm wafer size, the differences between the averages calculated based on the new and previously submitted data are more significant and could have an appreciable impact on the overall calculated CO_2e emissions. More information on the differences between the data contained in the two technology assessment reports received to-date and the previously submitted data is available in the subpart I TSD,

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[31] Available in ''*UPDATED Appendix A Process Emissions Characterization Data,*'' Semiconductor Industry Association, April 2018, and ''2020 Subpart I Consolidated Triennial Report, Appendices A–B,'' Semiconductor Industry Association, March 2020, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[32] The data submitted in previous years can be found in *Semiconductor Industry Association; Etch Process Equipment Emissions Characterization Data,* International SEMATECH Manufacturing Initiative Environmental Safety and Health Technology Center, February 2012, and *Draft Emission Factors for Refined Semiconductor Manufacturing Process Categories,* Office of Air and Radiation, May 2010, each of which is available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[33] See *Technical Support Document for Process Emissions from Electronics Manufacture (e.g., Micro-Electro-Mechanical Systems, Liquid Crystal Displays, Photovoltaics, and Semiconductors): Proposed Rule for Mandatory Reporting of Greenhouse Gases, Revised,* November 2010, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. In light of these findings, we request comment on whether the new data reflect recent technology changes or simply better represent technologies that have been in use over the long term (*i.e.,* at least since 2011, the first year of reporting under the GHGRP). This is important for understanding the time period to which the new data for these four factors are applicable.

We are also proposing to update the calculation methodology for MEMs and PV manufacturing to allow use of 40 CFR 98.3(a)(1), the current methodology for semiconductor manufacturing, in lieu of using 40 CFR 98.3(a)(2) for manufacture of MEMs and PV using semiconductor tools and processes. This would have the effect of applying the default emission factors in Tables I–3 and I–4 to these processes. In the *2019 Refinement,* use of semiconductor default emission factors for MEMs manufacturing is recommended when using semiconductor tools to manufacture MEMs. Similarly, we are also proposing the use of semiconductor emission factors for PV manufacturing that uses semiconductor manufacturing tools. It is expected that the use of semiconductor emission factors will result in more accurate emissions estimates when semiconductor manufacturing tools and processes are used.

The current Table I–8 does not distinguish N_2O emission factors either by the type of electronic device manufactured (semiconductor versus LCD) or by wafer size. Due to the increased availability of N_2O emission factor data, we are proposing to update Table I–8 to include distinct utilization rates for N_2O for semiconductor manufacturing and LCD manufacturing and, for semiconductor manufacturing, utilization rates by wafer size (<200 mm and 300 mm) and by process type.[34] The proposed emission factor for N_2O used in CVD thin film deposition for LCD manufacturing can be found in the *2019 Refinement.*[35] Currently there is no LCD manufacturing in the United States and thus, no U.S. data is available for LCD manufacturing.

We are also proposing to remove BEFs 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 (<0.03 $mtCO_2e$ and less than 0.0002 percent of emissions (in CO_2e) per metric ton of input gas consumed). This would result in: (1) removing the BEFs for C_4F_6 and C_5F_8 for all input gases used in wafer cleaning or plasma etching processes due to the combination of a low GWP (0.003 and 1.97, respectively) and low BEFs (less than 0.009); and (2) not adding BEFs for COF_2 and C_2F_4 for any input gas/process combination from the new data received in the 2020 or 2017 technology assessment reports because these BEFs are less than 0.2 and COF_2 and C_2F_4 have low GWPs (0.14 and 0.004, respectively). COF_2 does not have a chemical specific GWP in Table A–1 (it is currently assigned a default GWP of 2000 as an ''Other Fluorinated GHG''), but the 2018 WMO Scientific Assessment listed the 100-year GWP of COF_2 as ''<1.'' We calculated a precise GWP for COF_2 of 0.14 using the atmospheric lifetime and radiative efficiency provided in the 2018 WMO Scientific Assessment. (The method we used to calculate the GWP of COF_2 was the method we used to calculate precise GWPs for low-GWP compounds in the most recent update to GHGRP GWPs (79 FR 73750, December 11, 2014)). Currently, Table I–3 lists the BEF for C_4F_6 from all input gases as 'NA'. Similarly, Table I–4 currently lists the BEF for C_5F_8 from all input gases as 'NA'. Thus, for these two cases, there will be no change in reported emissions. Data reported to the GHGRP in 2013[36] indicates that, in total, for all semiconductor manufacturers reporting to the GHGRP in 2013, by-product emissions of C_5F_8 and C_4F_6 totaled 0.27 and 0.0004 $mtCO_2e$, respectively. Similarly, it is estimated that based on 2013 gas consumption COF_2 and C_2F_4 by-product emissions for the semiconductor fabs reporting to the GHGRP in 2013 would have been 0.43 $mtCO_2e$ and 0.005 $mtCO_2e$, respectively, if COF_2 and C_2F_4 emission factors were adopted. For the largest fabs, generation of all by-products listed above whose emission factors are being proposed for removal or exclusion from Tables I–3 and I–4 would result in less than 0.6 $mtCO_2e$ in combined emissions per fab and significantly less for smaller fabs. We are also proposing to modify the applicability of carbon-containing BEFs to chamber cleaning process subtypes where neither the input gas(es) nor the films being processed by the chamber contain carbon. In the emission factor tables in subpart I (*e.g.,* Table I–3 and I–4), there are cases where a perfluorocarbon BEF is provided even when the input gas i does not contain carbon (*e.g.,* NF_3). However, when none of the input gases contain carbon (*e.g.,* NF_3 or SF_6), and when the chamber being cleaned does not process films that contain carbon, then neither CF_4 nor other carbon-containing gases are expected to be formed during the process.[37] Thus, we are proposing that in cases where neither the input gas nor the films being processed in the tool contain carbon, the BEF for the carbon-containing by-products be set to zero (refer to variable ''B_{kij}'' in proposed equation I–8B). We are proposing to apply this provision at the process subtype level; a BEF of zero would only be used for a combination of input gas and chamber cleaning process subtype (*e.g.,* NF_3 in 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 would 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. An alternative approach would be to implement this change at the individual process or tool level, tracking gas consumption used in processes and tools that deposit films that contain carbon. This would lead to a more precise estimate of carbon-containing by-product emissions but may require

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[34] More information regarding the development of the proposed default emission factors can be found in the workbook titled, ''Data sets Supporting Revised Emission Factors.xlsx,'' (U.S. EPA, April 2020) and in the subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[35] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

[36] GHGRP data from RY2013 was used for this analysis as it is the last year for which it was relatively simple to estimate gas consumption due to revisions to the default emission factors applied in 2014 and later. For more information on how gas consumption was estimated, see U.S. EPA. *Inventory of Greenhouse Gas Emissions and Sinks:1990–2017* (2019). *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017.*

[37] Chamber cleaning processes, which typically use only one input gas, are not expected to generate carbon-containing byproducts from that input gas unless either the input gas or the film being removed contains carbon. The situation with etching and wafer cleaning processes, where multiple input gases are often used, is more complex. This is because input gases that do not contain carbon can still contribute fluorine to carbon-containing F–GHG by-products that obtain their carbon from other input gases, particularly if relatively fluorine-rich and carbon-poor by-products such as CF_4 predominate. The data set supporting the default emission factors proposed in this action includes by-product emission factors that have sometimes been calculated assuming that carbon-containing by-products are attributable to all input gases (including those lacking carbon) and that have other times been calculated assuming that carbon-containing by-products are only attributable to input gases that contain carbon.

greater apportioning than is otherwise required by the rule. We request comment on this alternative approach. Whether this revision was implemented at the process subtype or process level, it would improve the accuracy of the emissions estimate compared to the current rule by differentiating between process subtypes (or processes) where there is a source of carbon from which carbon-containing by-products may be generated and process subtypes (or processes) where there is no source of carbon from which carbon-containing by-products may be generated.

In addition, we are proposing to update the default emission factors for semiconductor manufacturing for use with the stack test method (Tables I–11 and I–12). These tables will continue to be needed to calculate emissions from consumption of each intermittent low-use F–GHG as defined in 40 CFR 98.98. The proposed default emission factors for Tables I–11 and I–12 were developed using the same data used to calculate revised emissions factors for Tables I–3 and I–4, as discussed above. To calculate the proposed default emission factors for Tables I–11 and I–12, which are process-independent, gas consumption by process type and wafer size was first estimated from emissions data reported under subpart I for RY2013. Gas consumption by process type was then used to weight the process-dependent emission factors from Tables I–3 and I–4 to arrive at the proposed default emission factors for Tables I–11 and I–12, respectively. Gas consumption by process type was used as a weighting factor to arrive at process-independent emission factors in order to have default emission factors that represent the average emission factor over total gas consumption by the industry for each wafer size.[38] Although the proposed emission factors proposed in this rulemaking differ slightly from the *2019 Refinement* due to the inclusion of newly available data, the methodology for developing Tables I–11 and I–12 are the same as those used to develop the Tier 2b tables in the *2019 Refinement.* For more information on the EPA's method for estimating gas consumption from emission data reported under subpart I for RY2013, which was used in the *2019 Refinement,* see the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2017.*[39] The workbook ''Data Sets Supporting Revised Emission Factors'' also shows the calculations for deriving the emissions factors in Tables I–11 and I–12 from Tables I–3 and I–4 (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

We are requesting comment on three options regarding default emission factors for MEMS and PV manufacturing. One option is to allow MEMS and/or PV manufacturers to use either the current default emission factors for those sub-sectors in Tables I–5 (MEMS) and I–7 (PV) or the default emission factors for semiconductor manufacturing in Tables I–3 and I–4, as applicable. The second option is to remove Tables I–5 and I–7 from subpart I and to require MEMS and/or PV manufacturers to use the default emission factors in Tables I–3 and I–4, as applicable. The third option is to continue to require MEMS and PV manufacturers to use the default factors in Tables I–5 and I–7, respectively. Information gathered during the development of the *2019 Refinement* and through the GHGRP indicates that the emission factors for semiconductor manufacturing in Tables I–3 and I–4, as applicable, are often, and perhaps always, applicable to MEMS and PV manufacturing. (In the *2019 Refinement,* semiconductor default emission factors are applied to MEMS manufacturing that is ''carried out using tools and processes similar to those used to manufacture semiconductors.'') However, we request comment on the extent to which semiconductor manufacturing default emission factors are applicable to MEMS and PV manufacturing. We also request comment on whether the distinction between different wafer sizes that separates Table I–3 from Table I–4 is applicable to MEMS and/or PV manufacturing.

We are also proposing to revise the input gas and BEF values assigned to gas/process combinations where no default input gas emission factor is available (due to a lack of data) in 40 CFR 98.93(a)(6). Currently, if no default input gas emission factor is available for a particular gas/process combination, reporters must use a general default value of one for the input gas emission factor (*i.e.,* a utilization rate of zero) and a general default value of zero for the BEFs. This assumes that emissions equal consumption, *i.e.,* all gas used in a process is emitted, without any utilization or conversion into other gases. However, in the majority of cases where emission factor data are available, both CF_4 and C_2F_6 are emitted as by-products, and both CF_4 and C_2F_6 are long-lived GHGs with very high GWPs (see Table A–1). Where the input gas has a GWP similar to those of PFCs, accounting for the generation of CF_4 and C_2F_6 by-products is not expected to significantly change the GWP-weighted emissions calculated for the process compared to the current method, but where the input gas has a GWP significantly lower than those of PFCs, accounting for the generation of the by-products would considerably improve the estimate of GWP-weighted emissions compared to the current method. In both cases, accounting for the likely emissions of CF_4 and C_2F_6 would also lead to a better estimate of each species emitted. Thus, we propose to revise the general defaults where no default input gas emission factor is available to account for the likely partial conversion of the input gas into CF_4 and C_2F_6. Specifically, 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, we are proposing at 40 CFR 98.93(a)(6) that reporters would 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. It is assumed here in cases where data do not exist, that the input gas is partially converted into CF_4 and C_2F_6 during the process and the remainder is emitted. The default input gas emission factor is conservatively based on the least efficient gas in Table I–4 for etch processes (C_2F_6 in the revised Table I–4). The remainder of the input gas is assigned to CF_4 and C_2F_6. Due to a generally higher CF_4 BEF for most input gas/process combinations, the majority (75 percent) of the remaining mass is assigned to CF_4.

Additionally, we are proposing to update the default DREs in Table I–16 to reflect the incorporation of new data from the 2017 and 2020 technology assessment reports and a new approach to abatement system certification. Currently, Table I–16 to subpart I lists default DREs by gas and process type. Where data were unavailable for some gas and chamber cleaning process combinations, DRE values were set to a conservative value of 60 percent in the current tables.[40] Commenters have

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[38] For more information on the development of the proposed emission factors for Tables I–11 and I–12, see the explanation for the equivalent Tier 2b tables in the subpart I TSD in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[39] U.S. EPA 2019. Available at *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017.*

[40] For more information, see ''Technical Support for Accounting for Destruction or Removal Efficiency for Electronics Manufacturing Facilities under subpart I,'' (August 2012) prepared for the Final Amendments and Confidentiality

Continued

previously noted that where exceptionally conservative DREs exist, there is a large incentive to invest in measuring site-specific DREs. Based on the measured data received by the EPA, the EPA is proposing to assign chemical-specific DREs to all commonly used F–GHGs for the semiconductor manufacturing sub-sector without distinguishing between process types.[41]

We are proposing to revise the default DREs in Table I–16 by incorporating new data received via the 2017 and 2020 technology assessment reports. The proposed DREs were calculated using a simple arithmetic mean of all DRE data by gas. The DRE data sets submitted to the EPA by the U.S. electronics manufacturing industry, including both data received via the technology assessment reports and previously submitted data, contains 1,353 data points for DREs of F–GHGs (for a discussion on DREs for N_2O, see the subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). Of these, 58 of the data points corresponded to gases that are not known to be input gases or significant by-products (C_2F_4 and COF_2, see previous discussion on emission factors excluded from Tables I–3 and I–4). Thus, we are not proposing default DREs in Table I–16 for these gases. Data points were not included in the calculations of the proposed DREs if the data points were reported as corresponding to emissions control systems that were not certified to abate that particular gas. Additional data points were excluded from the calculations of the proposed DREs if an accurate DRE could not be measured due to detection limits. Negative DREs were also excluded from the calculation for all F–GHGs. All but two of the negative DREs submitted for F–GHGs were on emissions control devices that were not designed to abate that particular gas. For the two cases where the system was designed to abate the gas, the testers noted either low gas inlet or inherent noise in the measurement (*e.g.,* due to low inlet). For the DREs from systems recorded as not designed or certified to abate the input gas, the negative DREs were reported only for CF_4 and COF_2. Results from literature[42] indicate that CF_4 can be formed within some emission control systems that use hydrocarbon fuels by reaction between the fuel and fluorinated species (*e.g.,* F_2) emitted from a NF_3 remote plasma chamber clean. All but one of the negative CF_4 DREs are from remote plasma chamber cleaning processes. However, since not all abatement systems form CF_4, these data points were excluded from this analysis and this formation of CF_4 is accounted for separately in the proposed rule. Data points were also excluded from the calculation if the gas being measured was noted as being less than two percent of the total inlet fluoride to the abatement system during testing, as the error in measuring DREs for such low inlet concentrations may have biased the DREs low. It is also known in the industry that when extremely low concentrations (*e.g.,* 100 ppm) of F–GHGs in the abatement system are present, the system is less efficient at destroying the F–GHG. Including these DREs in an unweighted average would have a disproportionate effect on the estimated emissions. Lastly, additional data points were excluded if the abatement system required maintenance or repair (*e.g.,* due to fouling of the system due to poor water quality), or the abatement system was operated in a manner inconsistent with the manufacturer's recommendations (*e.g.,* using clean dry air (CDA) instead of O_2 as the oxidant, as is recommended by the manufacturer). The data sets include data for most gas-process combinations. The EPA also considered using the DREs published in the *2019 Refinement.*[43] However, some of the data included in the *2019 Refinement* are not available to the EPA due to confidentiality concerns. Thus, the EPA was only able to determine how this subset differed on average to the EPA data sets. The confidential data set had higher average DREs for most F–GHGs. This may be due to fact that this subset contained DREs as measured by abatement system manufacturers and may not be representative of actual fab conditions. The EPA has also received additional data via the 2020 technology assessment report that was not available during the development of the *2019 Refinement.* The most recent data set received from industry via the 2020 technology assessment report included a significant number of DRE values that were significant outliers. Many of these outliers were excluded due to the reasons discussed above. The EPA considered excluding additional data points from the DRE calculations for Table I–16 but did not have enough information to determine whether the data points were representative of fab operating conditions, due to abnormal conditions, or due to operating the abatement system outside of manufacturer specifications. The EPA is requesting comment on the conditions under which data points were measured and whether any correspond to conditions that were atypical or outside of the manufacturer's recommendation for operation of the abatement system. The DREs in the proposed rule include data from the 2020 and 2017 technology assessment reports and earlier data sets. As discussed above, all DRE data points from the technology assessment reports from abatement systems designed to abate the F–GHG input gas were included in the calculations of the proposed default DREs except in cases where: (1) the DRE was negative; (2) there were detection limit issues; (3) the inlet gas flow of the F–GHG measured was less than 2 percent of the inlet gas; (4) the abatement system required maintenance or repair; or (5) the abatement system was operated in manner inconsistent with the manufacturer's specifications. The subpart I TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424, describes the full data set and the default DREs considered, including the option of excluding significant outliers. Where data for gas-process combinations still do not exist (or there were less than 5 data points), there are sufficient data across the various gas/process combinations to assign DREs based on analogy with gases with similar chemical structures. The revised Table I–16 also includes proposed DREs for C_2HF_5, C_5F_8, and C_4F_8O based on their similarity to CHF_3 (for C_2HF_5 and C_5F_8) and c-C_4F_8 (for C_4F_8O). This results in C_2HF_5 and C_5F_8 being assigned a default DRE of 97 percent. Based on its similarity to c-C_4F_8, C_4F_8O is assigned a default DRE of 93 percent. The EPA is proposing to base the DRE for C_3F_8 on the DREs for a chemically similar F–GHG for which the EPA does have data.

Determination for Electronics Manufacturing Final Rule (78 FR 68162, November 13, 2013), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[41] See data sets ''UPDATED–04–02–2018-Triennial Report Data for EPA,'' ''Attachment B. New and Revised DRE Test Used in SIA Analysis of Alternative Default DREs'' from Comments of the SIA on the Greenhouse Gas Reporting Program: Proposed Amendments and Confidentiality Determinations for Subpart I (Docket Id. No EPA–HQ–OAR–2011–0028–0095), and ''Etch DRE Testing With Flow Data, March 6, 2012,'' [2020 Triennial Data set]. All are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[42] S.N. Li, *et al.* ''FTIR spectrometers measure scrubber abatement efficiencies,'' Solid State Technology, Vol. 45. (2002); Gray, Fraser, and Afroza Banu, ''Influence of CH_4-F_2 mixing on CF_4 by-product formation in the combustive abatement of F_2,'' Research Disclosure, Sept. 2018, both available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[43] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

C_3F_8 is expected to be no more difficult to abate than C_2F_6. Thus, the EPA is proposing to apply the DRE value for C_2F_6 (98 percent) to C_3F_8. A value of 98 is slightly higher than the DRE for C_3F_8 in the current rule (97 percent).[44] [45]

Since the data does not show statistically significant differences between process types,[46] we are proposing to remove the distinction by process type from Table I–16. In addition, we are proposing to equate the default DRE for each F–GHG to the straight average of the measured DREs for that F–GHG rather than setting the default DRE slightly below the average. The DREs currently in Table I–16 were developed using analysis of variance (ANOVA), which took into account the likely variations in abatement device performance across fabs and within a single fab (see the memorandum, *Final Technical Documentation—Revision of Default Utilization Rates and By-Product Formation Rates; Revision of Default Destruction and Removal Efficiencies for Semiconductor Facilities under subpart I; and Revision of Maximum Field Detection Limits for the Stack Test Method* (Alexis McKittrick, U.S. EPA, August 16, 2013), which was used in the development of the 2013 Final Rule (78 FR 68182, November 13, 2013) and is available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). A conservative approach was used because the DRE performance of abatement equipment can vary depending on the specific design of each manufacturer, which is often proprietary, and the actual conditions in the fab. However, here, we are proposing a more refined method for estimating controlled emissions that would still account for variability across manufacturers.

To account for the variations in device performance, we are proposing to modify the conditions under which the default DRE can be claimed. Currently, in 40 CFR 98.94(f), in order to claim the defaults provided in Table I–16, abatement equipment must be certified as specifically designed for F–GHG or N_2O abatement, and the abatement system must be certified as being properly installed, operated, and maintained according to the site maintenance plan for abatement systems. Site maintenance plans must also be based on the manufacturer's recommendations and specifications. The EPA is proposing to clarify the definition of operational mode in 40 CFR 98.98 to specify that operational mode means that the system is operated within the range of parameters as specified in the DRE certification documentation. Thus, the abatement system should only be considered operational and the default or certified lower DRE claimed when the system is operated within the range of parameters for which the system is certified to meet or exceed the claimed DRE. The specified parameters must include a range of total F–GHG or N_2O flows and total gas flows (with N_2 dilution accounted for) through the emissions control systems. For systems operated outside the range of parameters specified in the documentation supporting the DRE certification (*e.g.,* with total flows exceeding the original equipment manufacturer (OEM) specifications), a site-specific DRE could be measured and claimed. The system could then be considered operational within the range of parameters used to develop a site-specific DRE. We are also proposing to modify the conditions in 40 CFR 98.94(f) under which the default DRE may be claimed to require that the reporter, in order to claim the default value for that abatement system and gas, must: (1) certify that the abatement device is able to achieve a value equal to or greater than the default DRE value under the worst-case flow conditions during which the facility is claiming that the system is operational; and (2) provide supporting documentation. Worst-case flow conditions would be defined as the highest total F–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 emission control system is claimed to be operational. The certification would be based on testing of the abatement system model by the abatement system manufacturer using a scientifically sound, industry-accepted measurement methodology that accounts for dilution through the abatement system, such as the *Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing* (March 2010) (EPA 430–R–10–003, hereinafter ''EPA DRE Protocol,'' available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). If the equipment is certified to abate the F–GHG or N_2O but at a value lower than the default DRE, facilities would not be able to claim the default; however, facilities would be allowed to claim the lower manufacturer verified value. Site-specific measurements by the electronics manufacturer would still be required to claim a higher DRE than the default. The updated DREs reflect increased data and a refined approach rather than changes in the actual destruction rates. The updates to the DREs in Table I–16 would increase the accuracy of emissions reported by facilities and would be expected to reduce the number of facilities that choose to measure site-specific DREs.

d. Calculation of By-Products Produced in Hydrocarbon Fueled Abatement Systems To Improve the Accuracy of Emissions Estimates

We are proposing to add a calculation methodology that would estimate the emissions of CF_4 produced in hydrocarbon-fuel based emissions control systems that are not certified not to generate CF_4. (In this section III.E.1.d, all references to ''uncertified hydrocarbon-fuel based emission control systems'' refer to hydrocarbon-fuel based emissions control systems that are not certified not to generate CF_4.) The proposed calculation would be codified in equation I–9; we are proposing to renumber the previous equation I–9 as equation I–8b. Hydrocarbon-fuel based emission control systems are hydrocarbon-fuel based combustion devices that are designed to reduce emissions from exhaust streams from electronics manufacturing processes and include, but are not limited to, abatement systems that are designed to abate F–GHGs or N_2O. Studies have shown that direct reaction between molecular fluorine (F_2) and hydrocarbons (*e.g.,* CH_4) to form CF_4 can occur in hydrocarbon-fueled combustion emissions control systems, and the *2019 Refinement* includes calculations to account for the formation and emission of CF_4 from this source.[47] Where emissions control systems that generate CF_4 are used to abate NF_3 from RPC processes, the CF_4 is expected to account for 1.5 times the emissions of NF_3 (in CO_2e) that would have occurred with no abatement (see the subpart I

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[44] The 98-percent DRE for C_3F_8 in the current rule was assigned by analogy with C_2F_6, which also has an assigned DRE of 97 percent in the current rule (78 FR 68192, November 13, 2013).

[45] More information on the EPA's analysis of the DRE data can be found in the subpart I TSD and supporting documents (''Combined DRE data sets.xlsx'') in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[46] *Id.*

[47] S.N. Li, *et al.* ''FTIR spectrometers measure scrubber abatement efficiencies,'' Solid State Technology, Vol. 45. (2002); Gray, Fraser, and Afroza Banu, ''Influence of CH_4-F_2 mixing on CF_4 by-product formation in the combustive abatement of F_2,'' Research Disclosure, Sept. 2018, both available in this docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

TSD available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

Equation I–9 would be used to estimate the emissions of CF_4 from generation in emissions control systems by calculating the mass of the fluorine entering uncertified hydrocarbon-fuel based emissions control systems (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, $AB_{CF4,F2}$. The proposed default emission factor for this reaction ($AB_{CF4,F2}$) is 0.116.[48] This reaction is expected to result in significant emissions only where F_2 is used as an input gas or where large amounts of F_2 can be formed as a by-product of the decomposition of the cleaning gas into atomic fluorine and subsequent recombination of the unreacted fluorine into F_2. Thus, this equation would only apply to processes that use F_2 as an input gas or to RPC processes that use NF_3 as an input gas. When NF_3 is used as a cleaning gas during the RPC process, the vast majority of the NF_3 molecules (approximately 98 percent, based on the default values for ($1-U_{NF3,RPC}$)) are decomposed within the remote plasma unit to form fluorine and nitrogen radicals, ions, and excited species. While some of the fluorinated species clean the solid residues deposited on the chamber walls by combining with the residues to form gaseous by-products such as SiF_4, HF, COF_2, and CF_4, some fluorine atoms recombine to form molecular fluorine (F_2). Based on confidential data received from Edwards, Ltd.,[49] a manufacturer of abatement equipment, the proposed BEF for F_2 from NF_3 used in remote plasma clean processes is 0.5. This data was also used to update the *2019 Refinement.* The proposed by-product is reasonable considering that emission factor data for NF_3 from RPC processes submitted to the EPA show that emissions of NF_3 and CF_4 accounted for less than 20 percent of the total mass of fluorine in the NF_3 used in the process in all but one of the 123 processes measured, and generally significantly less, leaving at least 80 percent of the fluorine available to form F_2, SiF_4, and HF. (The last two compounds are formed when fluorine combines with solid residue on the chamber walls, but the EPA's emission factor data do not include specific information on the quantities of those compounds—or of the fluorine—formed in the process.) No data from processes that use F_2 as an input gas are currently available for the 1–U of F_2; however, data from NF_3-using processes (where most of the NF_3 is dissociated into atomic fluorine during the process) indicate that the 1–U value for F_2 may be near 0.7 (Confidential data received from Edwards, Ltd.,[50] 2018, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).[51]

As for other gas and process combinations where no data is available (listed as ''NA'' in Tables I–3 and I–4), a 1–U of 0.8 would be used for F_2 in equation I–9 for all process types. The EPA is seeking comment on whether there is data available to support an alternative 1–U for F_2. The addition of this calculation is expected to increase the accuracy of emissions estimates from electronics manufacturers that use emissions control equipment. Along with the new calculation, we are proposing 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: (1) use hydrocarbon-fuel-based emissions control systems 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 (2) assume in equation I–9 that one or more of those systems do not form CF_4 from F_2. These proposed provisions, which are patterned after the current provisions covering abatement systems from which facilities quantify emission reductions, would require that the facility 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 emissions control system manufacturer. The facility could perform the testing itself, or it could supply documentation from the emissions control system manufacturer that supports the certification. If the facility performed the testing, it would be 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 requests comment on whether there are other measurement methods that should be cited as examples or listed as options for this measurement. The EPA has considered that it may be difficult to adapt the EPA DRE Protocol to measure the rate of conversion from F_2 to CF_4 if the analytical methods cited in the Protocol (Fourier Transform Infrared (FTIR) and Quadrupole Mass Spectroscopy (QMS)) do not work well to measure F_2 flows. Instead, other measuring or metering methods, such as calibrated mass-flow controllers or electrochemical cells, may be more effective. The EPA requests comment on this and any other issues that may arise in adapting the EPA DRE Protocol to measure the rate of conversion from F_2 to CF_4 in hydrocarbon-fuel-based emissions control systems. These issues and means of handling them could then be specifically addressed in the final rule.

Given the potential sensitivity of a calculated stack emission factor to any emissions of CF_4 produced in hydrocarbon-fuel based emissions control systems, we are also proposing to amend paragraph 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 hydrocarbon-fueled emissions control systems. This would ensure that the calculated stack emission factor for CF_4 will not be underestimated due to a significant fraction of uncertified systems not

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[48] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document, and the subpart I TSD (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[49] The by-product emission factor for F_2 from NF_3 was calculated from 15 measurements of remote plasma clean processes following a variety of different Thin Film Deposition (TFD) processes. F_2 generation was estimated using a mass-balance approach that compared the mass of atomic fluorine (F) flowing into each process chamber in the form of NF_3 with the mass of fluorine exiting the process chambers in the form of SiF_4, COF_2, HF, and NF_3. The mass of fluorine that was not accounted for at the exhaust of the process chamber was assumed to be in the form of F_2.

[50] The by-product emission factor for F_2 from NF_3 was calculated from 15 measurements of remote plasma clean processes following a variety of different Thin Film Deposition (TFD) processes. F_2 generation was estimated using a mass-balance approach that compared the mass of atomic fluorine (F) flowing into each process chamber in the form of NF_3 with the mass of fluorine exiting the process chambers in the form of SiF_4, COF_2, HF, and NF_3. The mass of fluorine that was not accounted for at the exhaust of the process chamber was assumed to be in the form of F_2.

[51] All documents in the docket are listed at *https://www.regulations.gov.* Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute.

operating during the stack test. This proposed amendment is similar to the current requirement in 40 CFR 98.98(j)(1)(i), which requires at least 90 percent uptime averaged over all abatement systems during the stack testing period, but would now require that this specific set, hydrocarbon-fueled abatement systems that are not certified not to generate CF_4, also average at least 90 percent uptime during the test.

Because CF_4 may be formed from F_2 in any hydrocarbon-fuel-based emissions control system, not only abatement systems from which facilities claim reductions for purposes of reporting under subpart I, we are proposing to apply these provisions to all hydrocarbon-fuel-based emissions control systems used in electronics manufacturing facilities. This includes, but is not limited to, abatement systems as defined at 40 CFR 98.98. We are proposing to add a definition of ''hydrocarbon-fuel-based emissions control system'' to clarify the scope of coverage.

e. Revisions to Calibration Requirements for Abatement Systems

We are proposing to modify 40 CFR 98.97(d)(9)(ii) to require that a vacuum pump's purge flow indicators are calibrated every time a vacuum pump is serviced or exchanged. Some vacuum pumps' purge flow indicators are inaccurate and could deliver higher than indicated purge flow, exceeding the manufacturer's maximum flow specification for an abatement system.[52] Requiring calibration of the vacuum pumps would make it less likely that facilities would unknowingly claim an abatement system as operational during a time period when the abatement system is being operated outside of the manufacturer's flow specifications. Operating outside of the manufacturer's flow specifications is problematic because abatement systems are generally certified to meet or exceed the claimed DRE only when operated within a specified range of flow. We expect that this requirement would require calibrations every 1 to 6 months, depending on the process. The EPA is requesting comment on whether this approach and expected frequency is recommended or an approach that specifies the frequency of calibration, such as a minimum calibration of twice a year, would be a sufficient approach to maintain accurate flow rates.

2. Revisions To Streamline and Improve Implementation for Subpart I

a. Revisions to the Applicability Calculations for Subpart I

As discussed in section II.B.1 of this preamble, we are proposing to revise the applicability of subpart I. We are proposing to do this by adding a second option in 40 CFR 98.91(a) for estimating GHG emissions for semiconductor, MEMS, and LCD manufacturers; by revising the current applicability calculation for PV manufacturers; and by updating the emission factors used in the current applicability calculations for MEMS and LCD manufacturers. Currently, semiconductor, MEMS, and LCD manufacturers that have not previously reported under the GHGRP are required to calculate the subpart I contribution toward the 25,000 $mtCO_2e$ reporting threshold by using a calculation based on annual manufacturing capacity in substrate area (square meters, m^2). The calculation based on manufacturing capacity was adopted in part to limit the burden required for facilities to estimate their electronics manufacturing emissions for purposes of assessing the applicability of the GHGRP, as this method does not require either tracking gas consumption or apportioning gas consumption by process type. Instead, it is based on production capacity in terms of substrate area and default emission factors based on manufacturing type. However, this method may not be suitable for some facilities that have emissions per m^2 rates that are atypical and could consequently require some facilities that emit considerably less than 25,000 $mtCO_2e$ (unabated) to report under the GHGRP.

We are therefore proposing to add a second option for estimating emissions in 40 CFR 98.91(a)(1) and (2) that includes two new equations, I–1B and I–2B (and renumbering equations I–1 and I–2 to I–1A and I–2A, respectively). Specifically, we are proposing to add an optional calculation method that uses gas consumption multiplied by a simple set of emission factors (along with GWPs and a factor to account for heat transfer fluid) to estimate emissions in 40 CFR 98.91(a)(1) and (2). To estimate emissions, facilities would, for each F–GHG, apply an input gas emission factor of 0.8 and by-product gas formation factors of 0.15 for CF_4 and 0.05 for C_2F_6. The emission factors we are proposing for this optional calculation method are included in proposed new Table I–2 of subpart I of part 98 and are the same as the emission factors we are proposing in this rulemaking for gas and process combinations for which there is no default in Tables I–3, I–4, or I–5, as applicable; and the factors are discussed further under the updates to emission factors in section III.E.1.c of this preamble. As discussed in III.E.1.c of this preamble, almost all gas and process combinations emit CF_4 and C_2F_6 as by-products. Assigning default values for these by-products, instead of assuming emissions to be equal to gas consumption, would result in a more accurate emissions estimate, especially in cases where the input gas has a significantly lower or higher GWP than average. An emission factor of 1.0 would be applied to N_2O. Finally, as is currently required for the production-based method, the calculated emissions of each F–GHG and N_2O would be multiplied by the chemical-specific or default GWP for that GHG and the resulting CO_2e emissions would be summed across GHGs. The total would continue to be multiplied by a factor to account for the use of F–HTFs using equation I–4. The result would be the calculated subpart I contribution toward the 25,000 $mtCO_2e$-per-year emissions threshold in 40 CFR 98.2(a)(2).

Facilities that choose to use this option for their calculation method would be required to track annual gas consumption by GHG but would not be required to apportion consumption by process type for the purposes of assessing rule applicability. The EPA is proposing a simplified consumption-based calculation method option for semiconductor, MEMS, and LCD manufacturing facilities to provide a calculation method that could appropriately exclude some lower-emitting facilities that would otherwise be subject to subpart I. Facilities would continue to have the option to use the manufacturing capacity-based method for estimating emissions in 40 CFR 98.91(a)(1) and (2). Facilities using either method would continue to calculate total annual GHG emissions, including combined emissions from stationary fuel combustion units and other applicable source categories, for comparison to the 25,000 $mtCO_2e$ per year emission threshold in 40 CFR 98.2(a)(2).

Facilities that manufacture PV already have a consumption-based method in the current rule. However, currently, the applicability calculation for PV manufacturing includes only GHGs ''that have listed GWP values in Table A–1 to subpart A of this part.'' Because default GWPs are now available for F–GHGs that do not have chemical-specific GWPs in Table A–1, we are proposing to delete the limiting phrase ''that have listed GWP values in Table A–1.'' We are also proposing to revise

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[52] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

equation I–3 to be identical to the new equations I–1B and I–2B and to also use newly proposed Table I–2. As for semiconductor, MEMS, and LCD manufacturers, this revision is expected to increase the accuracy of the estimated emissions for determining applicability.

We are also proposing to revise the emission factors in Table I–1 used for estimating emissions for MEMS and LCD manufacturing when equation I–1A (based on production in substrate area) is used to assess the applicability of part 98. The emission factors currently in Table I–1 include emissions factors for semiconductor, LCD, and MEMS manufacturing. For semiconductor and LCD manufacturing, the emissions factors that are currently in Table I–1 are based on the Tier 1 default emission factors in Vol. 3, Ch. 6 *Electronics Industry Emissions* in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories.*[53]

For MEMS manufacturing, there were no IPCC Tier 1 factors available at the time of the 2010 Final Rule for Additional Sources of Fluorinated GHGs (75 FR 74774), and the emission factors were instead based on the IPCC Tier 2b SF_6 emission factor for semiconductors.[54] The *2019 Refinement* included an update to the IPCC Guidelines Tier 1 emission factors using newly available data.[55] For LCD and MEMS manufacturing, the EPA has tentatively determined that the new Tier 1 emission factors in the *2019 Refinement* would better reflect industry-wide technological trends and are expected to improve the accuracy of the emissions estimated for the GHGRP using Table I–1. However, for semiconductor manufacturing, emission rates vary significantly depending on the wafer size used for manufacturing, and therefore no single set of default emission factors accurately estimates emissions for all wafer sizes. The Tier 1 emission factors in the *2019 Refinement* are, overall, lower than those in the 2006 IPCC Guidelines because they reflect the increasing importance of the 300-mm wafer size technology, which has lower emission rates than the older but still significant 200-mm (or smaller) wafer size technology. (The Tier 1 emission factors in the *2019 Refinement* were developed assuming a 50/50 split between 200-mm and 300-mm wafer production.) To estimate emissions for manufacturing using the 200-mm wafer size, the *2019 Refinement* recommends that the Tier 1 emission factors in the 2006 IPCC Guidelines be used because they more accurately reflect emission rates for that wafer size than do the Tier 1 emission factors in the *2019 Refinement.* Use of the Tier 1 emission factors in the *2019 Refinement* would underestimate emissions from facilities manufacturing on wafers sized 200 mm or smaller. In addition, our analysis (CBI TSD *Comparison of Subpart I Emissions to New Tier 1 EFs,* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424 [56]) indicates that use of these factors would underestimate emissions from a few facilities manufacturing on wafers sized 300 mm. To maintain the simplicity of the applicability calculation in equation I–1A for semiconductors, the EPA prefers to retain a single set of default emission factors for semiconductors in Table I–1, and to ensure that facilities manufacturing on the 200-mm wafer size are not improperly excluded from coverage by the GHGRP, we are not proposing to revise the emission factors for semiconductor manufacturing in Table I–1. While this could result in overestimated emissions for some facilities that manufacture on the 300-mm wafer size, the EPA notes that such facilities would have the option to use gas consumption data rather than capacity in square meters to assess applicability, as discussed above.

There is no expected impact on the number of LCD manufacturing facilities reporting to the GHGRP due to the proposed update to those emission factors, as there are currently no known LCD manufacturers in the United States. For MEMS manufacturers, the proposed update to Table I–1 could possibly result in one additional facility reporting to the GHGRP (estimated to have annual emissions greater than or equal to 25,000 $mtCO_2e$). However, due to a lack of actual capacity data, it is difficult to assess with precision how many facilities, if any, would be impacted.

b. Revisions to the Frequency and Applicability of the Technology Assessment Report

For the reasons described in section II.B.3 of this preamble, we are proposing 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. (Other proposed changes to 40 CFR 98.96(y) are discussed in section III.E.1 of this preamble.) The purpose of the technology assessment report is to provide regular review of technology changes in the semiconductor manufacturing industry and ensure that default gas utilization rates, by-product formation rates, and DRE values accurately reflect changes in the industry's practices, such as the introduction of manufacturing on 450-mm sized wafers. In the 2012 proposed amendments to subpart I (77 FR 63538, October 16, 2020), we noted that the semiconductor manufacturing industry had historically been ''fast-evolving, achieving exponentially increasing processor speeds and improving manufacturing efficiencies through the rapid adoption of new manufacturing processes'' (see 77 FR 63565). At that time the EPA had identified the potential introduction of 450 mm wafer technology, as well as other new process technologies that could affect emissions. Therefore, we considered a three-year report appropriate for collecting information on changes in the semiconductor industry that would potentially affect emissions. However, following submission and review of the first three-year reports, we have determined that industrial advancements are occurring at a slower pace. As such, we are proposing to amend 40 CFR 98.96(y) to decrease the frequency of submission of the reports from every three years to every five years. Under the current rule, semiconductor manufacturing facilities are required to submit their next technology assessment report by March 31st, 2023 (concurrent with their RY2022 annual report). This proposed revision would affect the due date for that technology assessment, moving the due date from March 31, 2023, to March 31, 2025. Our review of the technology assessment reports submitted for RY2016 and RY2019 did not find significant technology changes within the industry over the three years the reports covered. Based on an assessment of the RY2016 and RY2019 reports (CBI memorandum, *Review of 2017 Subpart*

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[53] IPCC. Guidelines for National Greenhouse Gas Inventories, Volume 3, Ch. 6 Electronics Industry Emissions, 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[54] Refer to *Technical Support Document for Process Emissions from Electronics Manufacture (e.g., Micro-electro-mechanical Systems, Liquid Crystal Display, Photovoltaics, and Semiconductors),* November 2010, available in the docket for this rulemaking, Docket Id. No, EPA–HQ–OAR–2019–0424.

[55] See *Volume 3, Chapter 6. Electronics Industry Emissions* to the *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,* as cited above in this document.

[56] *Supra* note 51.

I Triennial Reports Submitted by the Electronics Industry (Transcarbon International, 2017, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424) [57] gas emissions and wafer size data that have been submitted to e-GGRT in annual reports, and information gathered from outside sources (summarized in a literature review, *Memorandum: Review of trade and scientific publications to identify significant recent changes in technologies and gas usage in electronic devices manufacturing,* prepared by Sébastien Raoux, Transcarbon International, and Brian Palmer, Eastern Research Group, Inc. (April 3, 2017), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424), we believe that a five-year period would provide updates to the EPA more in line with the pace of technological change within the semiconductor industry. Revising the frequency of submission to every five years would increase the likelihood that reports will include updates in technology rather than conclusions that technology has not changed. Because we have found that changes within the industry have been incorporated at a slower pace and do not anticipate significant changes in technology on a three-year frequency, the proposal to require submission of these reports on a five-year frequency would likely not significantly affect the quality of the data available annually in the GHGRP.

Second, we are proposing to revise the applicability of 40 CFR 98.96(y). Currently, any facility with emissions greater than 40,000 mtCO$_2$e in their most recently submitted emissions report must submit a technology assessment report, including facilities manufacturing devices only using wafer sizes smaller than 200 mm (*e.g.,* 150 mm). Because the focus of the technology assessment report is on semiconductor manufacturing using 200-mm, 300-mm, and potentially 450-mm wafers (see 40 CFR 98.96(y)(2)(i)–(iii)), we are proposing to restrict the reporting requirement in 40 CFR 98.96(y) to facilities that emitted greater than 40,000 mtCO$_2$e and produced wafer sizes greater than 150 mm (*i.e.,* 200 mm or larger) during the period covered by the technology assessment report. We are also proposing to 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 applicability of 40 CFR 98.96(y) is currently based on the emissions in a facility's most recently submitted report (typically the emissions occurring in the second-to-last year covered in the technology assessment report, *e.g.,* RY2022 emissions for the technology reports that would be submitted in 2023). However, because facilities that cease all operations related to subpart I are eligible to discontinue reporting under 40 CFR 98.2(i)(3), we are also proposing to further revise the applicability of 40 CR 98.96(y) to 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). For example, if a facility manufacturing on 300-mm wafers exceeded the 40,000 mtCO$_2$e threshold in 2023 but ceased operations in December of that year and has not since then resumed operations, that facility would not be required to submit a technology assessment report in March of 2025.

F. Subpart N—Glass Production

For the reasons described in section II.A.4 of this preamble, we are proposing two revisions to the recordkeeping and reporting requirements of subpart N of part 98 (Glass Production) to enhance the quality and accuracy of the data collected under the GHGRP. Subpart N currently requires calculation of CO$_2$ emissions using one of two methodologies, either direct measurement using CEMS, or a mass balance methodology based on mass, carbonate content, and fraction of calcination for each carbonate-based input material. For each option, reporters are required to provide the annual quantities of glass produced from each glass melting furnace, and the annual quantities of glass produced from all furnaces combined. The annual quantities of glass produced have been used historically in verification of reported emissions under the GHGRP for comparison to, and to check for temporal consistency with, carbonate content data and emissions estimates provided by facilities. Facilities also maintain records of monthly glass production rate for each glass furnace. We are proposing to revise the existing reporting and recordkeeping requirements for both CEMS and non-CEMS reporters to require that facilities report and maintain records of annual glass production by glass type. Specifically, we are proposing to revise 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 the annual quantity of glass produced in tons, by glass type, from each continuous glass melting furnace and from all furnaces combined. The major raw materials (*i.e.,* fluxes and stabilizers) that emit process-related CO$_2$ emissions in glass production are limestone, dolomite, and soda ash, though there are variations in ingredients and other carbonates may be used in smaller quantities. In general, the composition profile of raw materials is relatively consistent among individual glass types (*e.g.,* container, flat glass, fiber glass, specialty glass), however, some facilities make use of recycled glass in their production process. Differences in the use of recycled material, and other factors, lead to differences in emissions from the production of different glass types. The annual quantities of glass produced by type would provide a useful metric for understanding variations and differences in emissions estimates that may not be apparent in the existing annual production data collected, improve our understanding of industry trends, and improve verification for the GHGRP. The proposed data elements would also provide useful information to improve analysis of this sector in the U.S. GHG Inventory. As noted in the 2019 U.S. GHG Inventory report,[58] the EPA reviews the GHGRP data in the development of inventory estimates for this sector to help understand the completeness of emission estimates and for quality control. Including glass product type would increase the transparency of the data set produced by the Inventory. In addition to the proposed reporting of these data elements, we are proposing harmonizing revisions in 40 CFR 98.147(a)(1) and (b)(1), to add that records must also be kept on the basis of glass type.

We do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as annual production data by glass type is likely available in existing company records. The proposed changes would therefore result in minimal additional burden to reporters. We are also proposing related confidentiality determinations for the

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[57] *Supra* note 51.

[58] See U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* (EPA 2021), available at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.*

additional data elements, as discussed in section VI of this preamble.

G. Subpart P—Hydrogen Production

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

As discussed in section II.A of this preamble, we are proposing several amendments to enhance the quality of the data collected under subpart P of part 98 (Hydrogen Production).

Subpart P estimates CO_2 emissions from hydrogen production units using a carbon mass balance along with an assumption that all carbon is transformed to CO_2 and is emitted from the hydrogen production process. This assumption is reasonable for the majority of hydrogen production units because these facilities produce hydrogen using either steam methane reforming or partial oxidation, followed by a water-gas-shift reaction. The first step (steam methane reforming or partial oxidation) produces a mixture of carbon monoxide (CO) and hydrogen, commonly referred to as syngas. The water gas shift reaction uses water to react with the CO in the syngas to produce CO_2 and additional hydrogen. While the majority of hydrogen production units use the water-gas-shift reaction, some facilities only produce syngas as their product. Some facilities may also intentionally produce methanol as a product of these reactions. In these cases, the assumption that 100 percent of the carbon used in the process is converted to CO_2 and thus are direct CO_2 emissions from hydrogen production units is inaccurate.

As noted in section III.C of this preamble for subpart G (Ammonia Manufacturing), TFI has commented numerous times regarding its view of the lack of a true mass balance for subpart G. In several of their comments (specifically, TFI's Comments on the Proposed ''2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements,'' May 2, 2013, and Comments on the Proposed ''2015 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule,'' March 30, 2016),[59] [60] TFI stated that subpart P lacked a true mass balance because the emissions calculation methodology in 40 CFR 98.163 does not account for carbon that is bound in methanol or other by-products of the process and therefore is not emitted as CO_2. TFI pointed out that subpart P requires reporting of methanol that is intentionally produced and ''carbon other than CO_2'' that is transferred off site, but that the emissions calculation methodology in 40 CFR 98.163 still assumes that 100 percent of the carbon is emitted as CO_2 because the mass balance equations do not subtract out the carbon that leaves the facility as methanol or another product.

Syngas is used as a feedstock for chemical production, most commonly to produce methanol. Carbon transformed into methanol or other chemicals are not emitted as CO_2 unless the syngas is used directly as fuel. For fuel combustion units other than the hydrogen process units, and to which subpart C (General Stationary Fuel Combustion Sources) applies, the CO_2 emissions from syngas combustion would be reported under subpart C of part 98. In considering TFI comments, as noted in the preamble to the November 2013 amendments (78 FR 71935, November 29, 2013), we considered both the emissions from the production processes and consistency with the reporting requirements for other subparts. We note that subpart X (Petrochemical Production) uses a more direct mass balance approach in that carbon contained in produced products (*e.g.,* ethylene) is subtracted from the carbon contained in feedstocks to calculate CO_2 emissions. The EPA has tentatively concluded that requiring reporters subject to subpart P to report net CO_2 process emissions after subtracting out carbon contained in other products would provide a more accurate estimate of the direct GHG emissions from these processes and would provide consistency in our approach across the GHGRP. Therefore, the EPA is proposing to amend subpart P to allow the subtraction of carbon contained in products other than CO_2 (excluding methanol) and the carbon contained in methanol from the carbon mass balance used to estimate CO_2 emissions. The proposed revisions would add new paragraph 40 CFR 98.163(d) to allow facilities to adjust the calculated emissions from fuel and feedstock consumption to subtract the mass of both non-CO_2 carbon (excluding methanol) and carbon contained in the intentionally produced methanol in order to calculate net CO_2 process emissions. We are also proposing harmonizing revisions to the introductory paragraph of 40 CFR 98.163 and 40 CFR 98.163(b).

In conjunction with adding the new paragraph to 40 CFR 98.163(d), we are proposing a clarifying revision to the reporting requirements at 40 CFR 98.166(b)(1) to specify that the annual CO_2 emissions may be determined in accordance with either 40 CFR 98.163(b), the existing equations, or 40 CFR 98.163(d), the revision requiring the calculation of net CO_2 emissions using equation P–4. We are proposing to revise 40 CFR 98.166(d) to require reporting the mass of non-CO_2 carbon (excluding methanol) collected and transferred off-site for each process unit rather than for all process units combined, as currently reported. Reporters are already required to account for and report under 40 CFR 98.166(d) the mass of non-CO_2 carbon (excluding methanol) collected and transferred off-site for all process units combined and under 40 CFR 98.166(e) the mass of methanol produced for each process unit. This proposed revision would cause a slight increase in reporting burden, but the additional level of reporting is necessary to implement the requested change in the calculation method and facilitate report verification. The proposed revision would provide the same breadth of information that was previously reported to inform future policy decisions. Additionally, this data element may be determined using company records, which also should minimize the increased burden. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

As a result of the new equation P–4, the EPA is proposing to add two new monthly recordkeeping elements as part of the verification software records required in 40 CFR 98.167(e): (1) monthly mass of carbon other than CO_2 or methanol collected and transferred off site; and (2) monthly mass of methanol intentionally produced as a desired product. This proposed change is not expected to result in a significant increase in burden because both elements are already being reported on an annual basis. For reporters that do not produce carbon other than CO_2 (excluding methanol) or methanol, the requirements for recordkeeping would remain unchanged. We are also clarifying that retention of the file required in 40 CFR 98.167(e) satisfies

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[59] TFI's Comments on the Proposed ''2013 Revisions to the Greenhouse Gas Reporting Rule and Proposed Confidentiality Determinations for New or Substantially Revised Data Elements,'' Docket Id. No. EPA–HQ–OAR–2012–0934, May 2, 2013. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[60] TFI's Comments on the Proposed ''2015 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule,'' Docket Id. No. EPA–HQ–OAR–2015–0526–0064, March 30, 2016. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

the recordkeeping requirements for each hydrogen production unit.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart P

We are proposing several revisions to subpart P to streamline the requirements of this subpart and improve flexibility for reporters. First, we are proposing several revisions to address unconventional feedstocks being used for hydrogen production. For example, in RY2017, a new facility started reporting under subpart P that produced hydrogen via brine electrolysis. Additionally, we understand facilities are considering using anhydrous ammonia as a feedstock for hydrogen production. The test methods included in 40 CFR 98.164(b)(5) are generally not applicable for these feedstocks. Moreover, the reduced, annual measurement frequency allowances in 40 CFR 98.164(b)(2) and (3) are specific to ''*hydrocarbon* fuels and feedstocks having consistent composition'' [emphasis added].

To address the recent use of unconventional non-hydrocarbon feedstocks, and for the reasons described in section II.B.2 of this preamble, we are proposing to add an allowance in a new paragraph 40 CFR 98.164(b)(5)(xix) to use alternative methods 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. Similar provisions have been provided in other GHGRP subparts, such as subpart X. This proposed revision will ensure that subpart P will not mandate the use of inappropriate or unsafe methods for these unconventional feedstocks.

Additionally, we are proposing revisions to 40 CFR 98.164(b)(2) and (3) to allow the use of product specification information annually for non-hydrocarbon 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. Similarly, we are proposing revisions to 40 CFR 98.164(b)(3) to allow the use of product specification information annually for non-hydrocarbon 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. The value of 0.0006 kg/gallon was derived using 20 parts per million by weight and assuming the liquid that has a specific gravity of 0.8 (*i.e.,* a density of approximately 3.0 kg/gal). The current unconventional non-hydrocarbon fuels and feedstocks utilized in hydrogen production have very limited GHG emission potential and are currently an insignificant contribution to the GHG emissions from hydrogen production. Therefore, we consider it reasonable to provide a simple alternative of allowing use of product specification information on an annual basis for determining carbon content for these unconventional, non-hydrocarbon fuels and feedstocks.

We are also proposing revisions to 40 CFR 98.164(b)(5) to clarify that the methods in 40 CFR 98.164(b)(5) must be used for determining carbon content except for the newly proposed provisions for gaseous and liquid fuels and feedstocks that have a low carbon content as provided in paragraphs 40 CFR 98.164(b)(2) and (3). Additionally, we are proposing to revise paragraphs 40 CFR 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.'' This proposed revision does not alter the existing requirements for fuels and feedstocks, it simply clarifies the linkage between the requirements in paragraphs 40 CFR 98.164(b)(2) through (4) and (5) of the current rule.

These proposed revisions to address unconventional hydrogen production feedstocks would increase flexibility for reporters and clarify requirements to reduce the number of reporters performing monthly sampling and analysis using potentially inappropriate methods. We expect that the proposed changes would allow reporters using unconventional non-hydrocarbon fuels and feedstocks to use the proposed product specifications provisions and reduce the need for sampling and analysis. Even if the reporter cannot use the product specifications provisions, the proposed revision to allow the use of modified or alternative methods would likely reduce the analytical burden of trying to use hydrocarbon-focused methods for a non-hydrocarbon stream. While the proposed revisions would provide significant relief for those reporters using unconventional non-hydrocarbon fuels or feedstocks, the proposed change is expected to only affect a small number of reporters due to the limited number of reporters that currently use these types of feedstocks.

In providing these alternatives, we also evaluated whether amendments to the recordkeeping and reporting requirements were necessary. There are no direct reporting requirements for the analytical method used to determine carbon content. The recordkeeping requirements are included in 40 CFR 98.167(b), which requires retention of ''. . . records of all analyses and calculations conducted as listed in 40 CFR 98.166(b), (c), and (d).'' In reviewing these requirements, we noted that these recordkeeping requirements were not revised when the EPA added reporting requirements at 40 CFR 98.166(e) (79 FR 63787, Oct. 24, 2014). Therefore, we are proposing to revise the recordkeeping requirements at 40 CFR 98.167(b) to refer to paragraphs (b) through (e) of 40 CFR 98.166. We note that, for facilities using the proposed 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.

H. Subpart Q—Iron and Steel Production

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

For the reasons described in section II.A.4 of this preamble, we are proposing revisions to the reporting requirements for subpart Q of part 98 (Iron and Steel Production) to enhance the quality and accuracy of the data collected. Subpart Q currently requires calculation of CO_2 emissions using one of three methodologies: direct measurement using CEMS, carbon mass balance methodologies, or site-specific emission factors. Subpart Q requires that the CO_2 emissions be calculated and reported for the following types of units: taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, decarburization vessel, and direct reduction furnace. We are proposing to revise the existing reporting requirements at 40 CFR 98.176(g) for all unit types and all calculation methods to require that facilities report the type of unit, the annual production capacity, and the annual operating hours for each unit. The capacity of the unit as well as the level of operation have a significant influence on the emissions of that unit. Therefore, the annual production capacity in combination with annual operating hours would provide useful information for understanding variations in annual emissions and would provide useful information to verify reported data. We often contact facilities seeking to understand yearly variations in the emissions of a unit, and facilities explain that the variation was due to the unit not operating for a particular time period. If data on the capacity of the unit and the operating hours are included in the annual report, it could explain the variation and eliminate the need for correspondence with facilities. In addition, this data would provide useful information to understand trends across the sector and support analysis of these sources.

In general, we do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters. For facilities using the carbon mass balance method, this data is already included in the record keeping requirements described at 40 CFR 98.177(c) and (d). Although the record keeping requirement at 40 CFR 98.177(d) does not specify whether the data would be retained at the facility or unit level, we do not anticipate that reporting data at the unit level would present additional burden. For facilities using the CEMS method or the site-specific emission factor calculation method, we anticipate that this data would be readily available in company records. However, we seek comment on both these assumptions. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

For the reasons described in section II.A.5 of this preamble, we are proposing to correct equation Q–5 in 40 CFR 98.173(b)(1)(v). An error appears to have been introduced in equation Q–5 in revisions to the equation in a final rule published in 2016 (81 FR 89188, December 9, 2016). Specifically, the final rule inadvertently published the equation such that it appeared that the total CO_2 emissions from EAFs are determined as a fraction of, rather than the total of, carbon mass emissions from inputs to the furnace. The proposed revisions would correct the equation to remove the unnecessary fraction symbol and would not add additional burden for the calculation or reporting requirements for subpart Q.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart Q

For the reasons described in section II.B.2 of this preamble, we are proposing two revisions to subpart Q to streamline monitoring. First, we are proposing to revise 40 CFR 98.174(b)(2) to provide a new option for facilities to determine the carbon content of process inputs and outputs. Reporters are currently allowed to determine carbon content either through direct sampling using the methods provided in 40 CFR 98.174(b)(2) or from similar analyses provided by a supplier. We are proposing to allow reporters an additional third option to use analyses provided by material recyclers that manage process outputs for sale or use by other industries. Several of the process output materials used in iron and steel production are typically sent to recycling facilities (*e.g.,* secondary zinc recycling facilities), which process the material for supply to another entity. Such 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. In the 2009 Final Rule, we determined that the use of carbon content analyses from a material supplier was appropriate because the carbon content does not vary widely at a given facility for the significant process inputs and outputs that contain carbon, and because the EPA continued to account for variations in emissions due to changes in production rate, which are more likely to be a significant source of variability (*i.e.,* the quantity of carbon-containing materials that are inputs and outputs to the process more directly influence emissions). For these same reasons, we anticipate that analyses received from a material recycling entity would be a reliable source of carbon content. The proposed change would add flexibility for reporters by allowing an additional option for obtaining measurements, in lieu of direct sampling. We are proposing 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.

We are also proposing to revise 40 CFR 98.174(b)(2) to incorporate a new test method for carbon content analysis of low-alloy steel. The EPA has become aware that an additional method is available for analysis of carbon content, specifically, ASTM E415–17, *Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry* (2017). We have reviewed the method, which is targeted to this sector, and have tentatively concluded it is a valid method for the purposes of subpart Q monitoring and reporting. The EPA allows for the use of standard methods based on atomic emission spectrometry in other sections of the rule, 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, we are proposing to incorporate the method by reference in 40 CR 98.7 and cross-reference that incorporation in 40 CFR 98.174(b)(2) for use for steel, as applicable. The proposed test method would be an alternative method and would provide additional flexibility for reporters. We are also proposing a 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).

I. Subpart S—Lime Manufacturing

For the reasons discussed in this section and section II.A of this preamble, we are proposing several revisions to subpart S of part 98 (Lime Manufacturing) to improve the quality of the data collected from this subpart. First, for the reasons described in this section and in section II.A.2 of this preamble, we are proposing to amend subpart S to improve the methodology for calculation of annual CO_2 process emissions from lime production. The proposed revisions would account for CO_2 that is captured from lime kilns and used on-site. Under subpart S, reporters currently calculate CO_2 emissions by either operating and maintaining a CEMS as specified in 40 CFR 98.193(a) or (b)(1), or by using the mass balance methodology under 40 CFR 98.193(b)(2). All lime kilns that are subject to 40 CFR 98.193(b) must calculate and report process and combustion CO_2 emissions by using the procedures in either 40 CFR 98.193(b)(1), for estimation of combined process and combustion emissions from all lime kilns, or 40 CFR 98.193(b)(2), for estimation of process and combustion CO_2 emissions from all lime kilns separately. For those lime kilns that use 40 CFR 98.193(b)(2), calculation of annual CO_2 process emissions from all lime kilns is estimated through summing the following three values (per 40 CFR 98.193(b)(2)(iv)): (1) the product of a monthly site-specific emission factor and weight or mass for each type of lime produced, (2) the product of a monthly site-specific emission factor and each type of calcined byproduct or waste that is sold, and (3) the annual CO_2 emissions from each type of calcined byproduct or waste that is not sold. There is currently no allowance for subtraction of CO_2 that may be captured and used in another process on-site (*e.g.,* for use in a purification process or the manufacture of another product such as refined beet sugars, precipitated calcium carbonate, etc.).

In response to the 2009 Proposed Rule, one subpart S reporter, Specialty

Minerals Inc., submitted a comment that stated that subpart S does not include a ''deduction for the carbon dioxide that is taken up as a raw material'' for use in another product, resulting in ''an overstatement of total carbon dioxide emissions'' from lime manufacturing.[61] In section III.C of this preamble, we describe similar comments received from TFI requesting changes that would allow sources to subtract from direct facility emissions CO_2 that is being used in the manufacturing of other products on-site.

Following review of these comments, the EPA has tentatively concluded that allowing reporters subject to subpart S to report net CO_2 process emissions after subtracting out CO_2 captured and used in other on-site processes would provide a more accurate estimate of the direct GHG emissions from the lime manufacturing process and would provide consistency in our approach across the GHGRP. Therefore, we are proposing to modify equation S–4 to subtract the CO_2 that is captured and used in on-site processes, with corresponding proposed 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). We are also proposing minor amendments to the reporting elements in 40 CFR 98.196(b)(17) to clarify that we only intend to collect data on CO_2 that is captured and used on-site (*i.e.,* 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. The proposed changes would also correct some instances where reporters have provided values of CO_2 used on-site that exceed facility emissions, where they have inadvertently included CO_2 that was not captured on-site (*e.g.,* CO_2 purchased for water treatment), which incorrectly implied that the facility's emissions were net negative. The proposed amendments would not change the reporting of emissions from manufacture of lime products, calcined lime by-products, or waste; this information would continue to be collected. As such, the proposed amendments would provide the same breadth of information that was previously reported to inform future policy decisions.

Second, for the reasons described in section II.A.4 of this preamble, we are proposing to add 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. Subpart S reporters who use CEMS collect CO_2 emissions data through direct measurement, and no data on the chemical composition of the products, byproducts, or wastes at CEMS facilities are collected through the GHGRP.[62] As such, there is currently limited data available to the EPA to evaluate process emissions for reporters using CEMS. As we noted for cement production facilities in section III.D of this preamble, CEMS facility emissions are different from non-CEMS emissions because combustion and process emissions are typically vented through the same stack, causing process and combustion emissions to be mixed and indifferentiable. In order to be able to differentiate process emissions, we are proposing to collect other data elements from CEMS reporters that are not currently reported, including annual average results of the chemical composition analysis of lime products, byproducts, or wastes. 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 proposing to add data elements under 40 CFR 98.196(a) to collect annual averages of the chemical composition input data on a facility-basis. The proposed data elements include the annual arithmetic average calcium oxide content (metric tons CaO/metric tons lime) and magnesium oxide content (metric tons MgO/metric tons 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. The proposed data elements would rely on an arithmetic average of the measurements rather than requiring reporters to weight by quantities produced in each month. In addition to improving verification and data quality for the GHGRP, the proposed data elements will also improve the U.S. GHG Inventory, which could use the proposed data elements to disaggregate process and combustion emissions that are reported by facilities using CEMS.

Similarly, in order to improve verification, we are proposing to collect 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)). These proposed amendments would allow the EPA to build verification checks for the actual inputs entered (*e.g.,* MgO content). We currently rely on verification checks within the IVT to check the accuracy of inputs and reported emissions from non-CEMS reporters, however, these checks are of limited usefulness since we lack the information to develop specific anticipated ranges or references for the entered data. Reporters using the mass balance methodology are currently required to report the annual average results of chemical composition analysis of each type of lime product produced and calcined byproduct or waste sold, but do not supply data for byproducts or wastes not sold. The EPA is proposing to add 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). Because the proposed 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 IVT. These proposed data elements would inform and improve the EPA's existing reference checks and allow the EPA to build additional checks for the data that are currently verified through IVT. The proposed amendments would improve the verification of entered data and confirm the veracity of reported emissions.

We do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as these data are likely already available in existing company records. However, we are requesting comment on whether any of

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[61] Specialty Minerals Inc.'s Comments on the Proposed 2009 Greenhouse Gas Reporting Rule, Docket Id. No. EPA–HQ–OAR–2008–0508–0907, June 4, 2009. Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[62] Subpart S reporters who use the mass balance methodology under 40 CFR 98.193(b)(2) currently estimate CO_2 emissions using monthly chemical composition data as inputs to calculate emissions factors for the lime produced, calcined byproducts and wastes sold, and calcined byproducts and wastes not sold. These data inputs are not collected by the EPA but are only entered into the EPA's Inputs Verification Tool, which conducts verification checks at the time of report submission but does not retain the data entered.

the above listed data elements would not be readily available to reporters. Reporters using the mass balance methodology are expected to have very minimal changes to reporting, as the chemical composition averages and quantities we are proposing can be calculated from the inputs that are currently entered into IVT. Finally, we are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

J. Subpart W—Petroleum and Natural Gas Systems

We are proposing several revisions to subpart W (Petroleum and Natural Gas Systems). Section III.J.1 of this preamble presents proposed amendments that would improve the quality of data collected, including new requirements for reporting of additional emission sources, updated emission factors, new and revised reporting requirements, and clarification of reporting requirements that reporters have indicated are unclear, as described in section II.A of this preamble. We are also proposing revisions described in section III.J.2 of this preamble that would streamline and improve implementation, including removing redundant or unnecessary reporting requirements, and providing additional flexibility in the calculation methods and monitoring requirements for some emission sources, as described in section II.B of this preamble. We are proposing the miscellaneous technical corrections and clarifications described in section III.J.3 of this preamble. Finally, section III.J.4 of this preamble describes the provisions for which we propose subpart W reporters would be able to use best available monitoring methods (BAMM) for RY2023. We are also proposing related confidentiality determinations for new or revised data elements that result from these proposed amendments, as discussed in section VI of this preamble.

In addition, on November 15, 2021 (86 FR 63110), the EPA proposed under CAA section 111(b) NSPS for new, reconstructed, and modified oil and natural gas sources, *i.e.,* sources for which owners or operators commence construction, modification, or reconstruction after November 15, 2021 (40 CFR part 60, subpart OOOOb) (hereafter referred to as ‘‘NSPS OOOOb’’), as well as emissions guidelines under CAA section 111(d) for existing oil and natural gas sources, *i.e.,* sources for which owners or operators commence construction, modification, or reconstruction on or before November 15, 2021 (40 CFR part 60, subpart OOOOc) (hereafter referred to as ‘‘EG OOOOc’’) (the sources affected by these two proposed subparts are collectively referred to in this preamble as ‘‘affected sources’’). While the standards in NSPS OOOOb would directly apply to new, reconstructed, and modified sources when finalized, the final EG OOOOc would not impose binding requirements directly on sources; rather it would contain guidelines, including presumptive standards, for states to follow in developing, submitting, and implementing plans to establish standards of performance to limit GHGs (in the form of methane limitations) from existing oil and gas sources within their own states. If a state does not submit a plan to the EPA for approval in response to the final emission guidelines, or if the EPA disapproves a state's plan, then the EPA must establish a Federal plan that would apply to existing sources within that state that are not covered by a state plan. In addition, a Federal plan could apply to facilities located on tribal land that do not request approval to develop a tribal implementation plan similar to a state plan. Once the Administrator approves a state plan under CAA section 111(d), the plan is codified in 40 CFR part 62 (Approval and Promulgation of State Plans for Designated Facilities and Pollutants) within the relevant subpart for that state.[63] 40 CFR part 62 also includes all Federal plans promulgated pursuant to CAA section 111(d). Therefore, rather than referencing the presumptive standards in EG OOOOc, which would not directly apply to sources, the proposed amendments to subpart W reference 40 CFR part 62.

Similar to the 2016 amendments to align subpart W with certain requirements in 40 CFR part 60, subpart OOOOa (hereafter referred to as ‘‘NSPS OOOOa’’) (81 FR 86500, November 30, 2016), we are proposing revisions to certain requirements in subpart W relative to the requirements proposed for NSPS OOOOb and the presumptive standards proposed in the EG OOOOc (which would inform the standards to be developed and codified under 40 CFR part 62). Specifically, we are proposing amendments to the subpart W calculation methodologies for natural gas pneumatic devices and equipment leak surveys related to the proposed NSPS OOOOb and presumptive standards in EG OOOOc, and we are proposing new reporting requirements for ‘‘other large release events’’ as defined in subpart W that would reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62. These proposed amendments are described in sections III.J.1.a, k, and m, respectively. These proposed amendments, if finalized, would not apply to individual reporters unless and until their emission sources are required to comply with either the final NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62. In the meantime, reporters would comply with the applicable provisions of subpart W for sources not subject to NSPS OOOOb or 40 CFR part 62.

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

As further described in section II.A of this preamble, the EPA is proposing amendments that would ensure that accurate data are being collected under the rule, improve the accuracy of emissions reported under part 98, and enhance the overall quality of the data collected under the GHGRP. Consistent with section II.A.1 of this preamble, we are proposing to incorporate recent data to update selected subpart W emission factors. Where emission factors are currently provided in subpart W for certain emission source types, those emission factors were based on the best available public data at the time that subpart W was promulgated. In the years since promulgation of subpart W, additional data have been collected for some source types as part of emissions studies, and the EPA has reviewed and evaluated the data in these studies. Based on those evaluations, the EPA is proposing to update selected subpart W population emission factors[64] for natural gas pneumatic device vents across a variety of industry segments and equipment leaks from the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments. The EPA is also proposing revisions to the leaker emission factors for all industry segments conducting equipment leak surveys to account for differences in the leak detection methodologies. Consistent with section II.A.2 of this preamble, the EPA is proposing amendments to improve calculation methodologies for emissions from natural gas pneumatic pumps,

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[63] 40 CFR part 62 contains a subpart for each of the 50 states, District of Columbia, American Samoa, Puerto Rico, Virgin Islands, and Northern Mariana Islands.

[64] When the total emissions from all leaking sources of the same type are divided by the total count of that source type, then the resultant factor is referred to as a population emission factor. When the total emissions from all leaking sources of the same type are divided by the total count of leaking sources for that source type, then the resultant factor is referred to as a leaker emission factor.

centrifugal compressors, reciprocating compressors, equipment leak surveys, combustion units, and sources that use the acoustic leak detection method for leak detection. Consistent with section II.A.3 of this preamble, we are proposing to add calculation and reporting requirements for ''other large release events,'' which are emission events that are not sufficiently accounted for using the current subpart W methodologies, and emissions from uncombusted methane from compressor engines. We are also proposing to require facilities in the Onshore Natural Gas Processing industry segment to begin calculating and reporting emissions from natural gas pneumatic devices and proposing to require facilities in the LNG Import/Export industry segment to begin calculating and reporting emissions from acid gas removal vents. Consistent with section II.A.4 of this preamble, we are proposing to add or revise reporting requirements to better understand and characterize the emissions from acid gas removal units, glycol dehydrator vents, liquids unloadings, atmospheric storage tanks, associated gas flaring, flare stacks, and equipment leaks, as well as to better characterize facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. Finally, consistent with section II.A.5 of this preamble, we are proposing to clarify calculation and reporting requirements for natural gas pneumatic devices, natural gas driven pneumatic pumps, blowdown vent stacks, atmospheric storage tanks (including requirements for open thief hatches), associated gas venting and flaring, centrifugal and reciprocating compressors, combustion devices, and facilities in the Onshore Natural Gas Transmission Pipeline industry segment, in part to address questions asked by reporters to the GHGRP Help Desk and in verification correspondence via e-GGRT.

a. Natural Gas Pneumatic Device Vents

Revisions to emission factors. Subpart W requires calculation of GHG emissions from natural gas pneumatic device venting using default population emission factors multiplied by the number of devices and the average time those devices are ''in-service'' (*i.e.,* supplied with natural gas). Subpart W provides two sets of pneumatic device emission factors, one for devices in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments and one for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments. Each set of emission factors consists of emission factors for three different types of natural gas pneumatic devices: continuous low bleed devices, continuous high bleed devices, and intermittent bleed devices.[65]

The EPA has become aware of several studies on emissions from natural gas pneumatic device vents since subpart W was first promulgated. For example, in April 2015, the EPA reviewed three recently published studies on emissions from pneumatic devices (also referred to as ''pneumatic controllers'' within the studies as well as in NSPS OOOOa, NSPS OOOOb, and EG OOOOc) at onshore production facilities and evaluated those studies for use in the U.S. GHG Inventory.[66] As part of this proposed rulemaking, we have reviewed these and other available studies to evaluate the potential for revisions to the natural gas pneumatic device emission factors in subpart W. For more information regarding this review, see the document *Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule—Petroleum and Natural Gas Systems,* (hereafter referred to as ''subpart W TSD''), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

As part of our review, we found there are significantly more data available now by which to characterize pneumatic device emissions. Therefore, consistent with section II.A.1 of this preamble, we are proposing to amend the emission factors for the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Transmission Compression, and Underground Natural Gas Storage industry segments. We are also proposing to add pneumatic device venting as an emission source for the Onshore Natural Gas Processing industry segment using the same emission factors we are proposing for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments, consistent with section II.A.3 of this preamble.

Intermittent bleed pneumatic devices subject to surveys. As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using optical gas imaging (OGI) or other technologies. As noted in the introduction to section III.J of this preamble, the EPA recently proposed NSPS OOOOb and EG OOOOc for oil and natural gas sources. Under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc (which would inform the state plans or, if necessary, the Federal plan in 40 CFR part 62), nearly all covered pneumatic devices (continuous bleed and intermittent vent) would be required to have a methane and volatile organic compound (VOC) emission rate of zero. The only exception would be for pneumatic devices in Alaska at locations where on-site power is not available, in which case owners and operators would be required to use low bleed pneumatic devices in place of high bleed pneumatic devices (unless a high bleed device is needed for a functional need such as safety), and to verify that any intermittent bleed pneumatic devices operate such that they do not vent when idle by monitoring these devices during the fugitive emissions survey.

We envision relatively few intermittent bleed pneumatic devices under the proposed zero-emission standard and presumptive standard for these pneumatic devices, compliance with which would require the use of non-emitting devices. As noted in the previous paragraph, we proposed in NSPS OOOOb and EG OOOOc to require periodic monitoring of those few intermittent bleed pneumatic devices. In addition, as noted in section III.J of this preamble, the proposed amendments that would apply to sources subject to the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62 would not become effective for individual reporters unless and until their emission sources become subject to and are required to comply with either the final NSPS OOOOb or an

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[65] The development of the current emission factors for natural gas pneumatic devices is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[66] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: Potential Revisions to Pneumatic Controller Emissions Estimate (Production Segment).* April 2015. Available at *https://www.epa.gov/sites/production/files/2015-12/documents/ng-petro-inv-improvement-pneumatic-controllers-4-10-2015.pdf.*

approved state plan or applicable Federal plan in 40 CFR part 62. Prior to that time, a reporter may elect to conduct inspections or surveys of their intermittent bleed pneumatic devices. Therefore, similar to the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA is proposing amendments to subpart W to provide an alternative methodology to calculate emissions from intermittent bleed pneumatic devices based on the results of inspections or surveys, consistent with section II.A.2 of this preamble. Specifically, for facilities that would be required to inspect their intermittent bleed pneumatic devices requirements under NSPS OOOOb or an approved state plan or the applicable Federal plan in 40 CFR part 62 (to the extent there are any) or facilities that elect to conduct routine monitoring surveys of their existing natural gas intermittent bleed pneumatic devices consistent with the methods in NSPS OOOOb prior to becoming subject to 40 CFR part 62, we are proposing to provide an alternative calculation methodology analogous to a ''leaker factor'' approach used for equipment leaks. Reporters using this calculation methodology would report the total number of natural gas intermittent bleed pneumatic devices at the facility, the frequency of monitoring, the number of devices found to be malfunctioning, and the average time the malfunctioning devices were malfunctioning. For more information regarding this proposed alternative calculation methodology for natural gas intermittent bleed pneumatic devices, see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

Hours of operation of natural gas pneumatic devices and natural gas driven pneumatic pumps. In correspondence with the EPA via e-GGRT, reporters have indicated that there is confusion over the use of the term ''operational'' in the definition of variable ''T_t'' in equation W–1 in 40 CFR 98.233(a) and the term ''in operation'' in the reporting requirements in 40 CFR 98.236(b)(2). Both the current emission factors and the proposed updated emission factors described earlier in this section for natural gas pneumatic devices were developed by taking both periods of actuation and periods without actuation into account;[67] in other words, the emission factors are population emission factors. To calculate emissions accurately using a population emission factor, the average number of hours used in equation W–1 should be the number of hours that the devices of a particular type are in service (*i.e.,* the devices are receiving a measurement signal and connected to a natural gas supply that is capable of actuating a valve or other device as needed). Therefore, consistent with section II.A.5 of this preamble, we are proposing to revise the definition of variable ''T_t'' in equation W–1 and the corresponding reporting requirement in 40 CFR 98.236(b)(2) to use the term ''in service (*i.e.,* supplied with natural gas)'' rather than ''operational'' or ''in operation.''

Similarly, the population emission factor for natural gas driven pneumatic pumps was developed using measurements taken during actuations together with manufacturer data and observed operational data at facilities (*e.g.,* pump actuation rate).[68] In other words, the emission factor represents the average emissions over the period when the pump is operating, not just the emissions during periods when the pump was actuating. Therefore, we are also proposing to revise the definition of variable ''T'' in equation W–2 in 40 CFR 98.233(c)(1) for natural gas driven pneumatic pumps to use the term ''in service (*i.e.,* supplied with natural gas),'' and we are proposing to use that same term in the corresponding reporting requirement in proposed 40 CFR 98.236(c)(4).

b. Natural Gas Driven Pneumatic Pump Venting

The current procedures in subpart W for calculating and reporting emissions from natural gas driven pneumatic pump venting are specified in 40 CFR 98.233(c) and 40 CFR 98.236(c). The inputs to equation W–2 in 40 CFR 98.233(c) are the total number of natural gas driven pneumatic pumps and average estimated number of hours in the operating year the pumps were operational. Reporters then report these inputs along with the emissions under 40 CFR 98.236(c). As the calculated emissions are vented emissions from natural gas driven pneumatic pumps, the intent is that the total number of natural gas driven pneumatic pumps should include only those pumps that are vented directly to the atmosphere (*i.e.,* uncontrolled). However, based on contact with reporters, we understand that emissions from some natural gas driven pneumatic pumps are routed to controls, particularly flares or combustion units. Flared emissions from natural gas driven pneumatic pumps are not required to be calculated and reported separately from other flared emissions. Instead, emission streams from natural gas driven pneumatic pumps that are routed to flares are required to be included in the calculation of total emissions from the flare according to the procedures in 40 CFR 98.233(n) and reported as part of the total flare stack emissions according to the procedures in 40 CFR 98.236(n), in the same manner as emission streams from other source types that are routed to the flare. Similarly, emissions from natural gas driven pneumatic pumps that are routed to a combustion unit are required to be combined with other streams of the same fuel type and used to calculate total emissions from the combustion unit as specified in 40 CFR 98.233(z) and reported as part of the total emissions from the combustion unit as specified in 40 CFR 98.236(z).

In correspondence with the EPA via e-GGRT, some reporters have expressed confusion regarding the requirements for natural gas driven pneumatic pumps that are routed to flares or combustion devices, particularly between 40 CFR 98.236(c) (for vented emissions) and 40 CFR 98.236(n) or (z) (for flared or combusted emissions, respectively). Additionally, the counts of controlled natural gas driven pneumatic pumps currently are not reported separately from counts of vented natural gas driven pneumatic pumps under 40 CFR 98.236(c), and the emissions currently reported from flares and combustion units are not attributed specifically to natural gas driven pneumatic pumps. This lack of reported information leads to uncertainty in verification of reported data when there are significant changes in reported data at a facility from one year to the next, which can result in additional communication with the reporter to clarify whether or not the changes are an error. The lack of reported information also means changes in the trends related to implementation of such controls relative to trends in overall use of natural gas driven pneumatic pumps in the petroleum and natural gas systems source category would be difficult to track. In addition, there are other rules

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[67] As noted previously, the development of the current emission factors for natural gas pneumatic devices is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[68] The development of the emission factor for natural gas pneumatic pumps is described in *Greenhouse Gas Emissions Reporting from the Petroleum And Natural Gas Industry: Background Technical Support Document,* U.S. EPA, November 2010, (Docket Id. No. EPA–HQ–OAR–2009–0923–3610), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

that require the control of pneumatic pumps (*e.g.,* NSPS OOOOa), so we expect that there will be an increase in the number of natural gas driven pneumatic pumps that are routed to controls as more facilities become subject to those rules.

Thus, consistent with section II.A.2 of this preamble, we are proposing to revise 40 CFR 98.233(c) to clarify requirements for calculating emissions from both natural gas driven pneumatic pumps that are vented to the atmosphere and controlled natural gas driven pneumatic pumps that are consistent with the intent of the current rule. Specifically, we are proposing to revise 40 CFR 98.233(c) introductory text and the definitions of the terms ''Count'' and ''T'' in equation W–2 to further clarify that the provisions of 40 CFR 98.233(c)(1) and (2) should only be used to calculate emissions from natural gas driven pneumatic pumps venting directly to the atmosphere. We are proposing to add 40 CFR 98.233(c)(3) to specify that if the emissions are flared, then flared emissions would be calculated using the method for flare stack emissions in 40 CFR 98.233(n) and reported as flare stack emissions under 40 CFR 98.236(n). If emissions are routed to a combustion device, then emissions would be calculated using the methods for combustion devices as specified in 40 CFR 98.233(z) and reported as specified in 40 CFR 98.236(z). Finally, if the emissions are routed to vapor recovery and are not subsequently routed to a combustion device, then we are proposing that reporters would not calculate or report emissions. If a natural gas driven pneumatic pump is vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, the reporter would calculate emissions using all applicable procedures and adjust the number of hours used in equation W–2 as needed. We request comment on whether pneumatic pumps are routed to vapor recovery systems and whether there are other controls that should be addressed with these new provisions. In addition, we request comment on whether flared emissions associated with natural gas driven pneumatic pumps should continue to be reported as flare stack emissions under 40 CFR 98.236(n) or should be reported in the natural gas driven pneumatic pumps emission source under 40 CFR 98.236(c).

We are also proposing to add new reporting elements in 40 CFR 98.236(c) to align with the proposed clarifications to the emission calculation procedures. Specifically, we are proposing to expand the current requirement to report the total count of natural gas driven pneumatic pumps to three separate counts: the number of natural gas driven pneumatic pumps that are vented directly to atmosphere (*i.e.,* uncontrolled); the number of natural gas driven pneumatic pumps that are routed to a flare, combustion, or vapor recovery (*i.e.,* controlled); and the total number of natural gas driven pneumatic pumps at the facility. The total count of pneumatic pumps is a proposed reporting element along with the counts of uncontrolled and controlled pneumatic pumps because the total count would not always be equal to the sum of the other two counts. For example, a reporter that switches from one scenario to another during a year for a particular pneumatic pump (*e.g.,* from vented to flared) would include that pneumatic pump in the count of pumps that vent directly to atmosphere and in the count of pumps that are routed to flares, but that pneumatic pump would only be counted once towards the total number of pneumatic pumps. The number of pneumatic pumps vented directly to the atmosphere would be equal to the ''Count'' in equation W–2 and would be used in the verification of annual reports to the GHGRP. The total count of pneumatic pumps at the facility and the number of pneumatic pumps that are routed to a flare, combustion, or vapor recovery would provide the EPA with information to better characterize emissions from this source, including how many pneumatic pumps are controlled across the industry, how often pneumatic pumps are both controlled and vented directly to the atmosphere in the same year, and how the use of controls for pneumatic pumps changes across multiple years.

c. Acid Gas Removal Vents

Acid Gas Removal Units at LNG Import/Export Facilities. Emissions from acid gas removal units are currently reported for three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, and Onshore Petroleum and Natural Gas Gathering and Boosting. However, prior to becoming LNG, natural gas is treated to specifications more stringent than pipeline quality natural gas to remove nearly all of the heavy hydrocarbons, mercury, CO_2, sulfur compounds, and other impurities to prevent problems with the liquefaction process (*e.g.,* CO_2 and hydrogen sulfide can cause freezing and plugging in downstream units once the gas is liquefied). Therefore, liquefaction plants at LNG export facilities may include acid gas removal units, and those emissions are not currently reported to the GHGRP if the acid gas removal unit vents are vented directly to the atmosphere. Emissions from acid gas removal unit vents that are routed to flares or thermal oxidizers that meet the subpart W definition of flare in 40 CFR 98.238 are reported under the flare stacks emission source, but they are not characterized as acid gas removal emissions. LNG export facilities may receive natural gas that has already been treated in a natural gas processing plant as well as raw material from dedicated gas fields, so the emissions from acid gas removal units at these facilities can comprise a significant portion of the facility's emissions if the gas received at an LNG export facility has a relatively high CO_2 content.[69]

Therefore, consistent with section II.A.3 of this preamble, the EPA is proposing to revise 40 CFR 98.232(h) and 40 CFR 98.236(a)(7) to add acid gas removal vents to the list of emission sources for which facilities in the LNG Import/Export industry segment must calculate and report emissions. Facilities in this industry segment with an acid gas removal unit would use one of the four calculation methods currently provided in 40 CFR 98.233(d) and report emissions as currently provided in 40 CFR 98.236(d). Facilities in this industry segment without an acid gas removal unit would only be required to indicate that in their report. We request comment on whether all four calculation methods currently provided in 40 CFR 98.233(d) are appropriate for facilities in the LNG Import/Export industry segment and if not, how specific calculation methods could be adjusted to be more applicable to this industry segment. In addition, we request comment on whether there are other emission sources at LNG Import/Export facilities with significant emissions that should be added to subpart W (*e.g.,* glycol dehydrators), as well as whether there are other industry segments with acid gas removal units that are not reported and make up a significant portion of facility emissions.

Calculation method 4 reporting. Reporters with acid gas removal units that elect to calculate emissions using Calculation Method 4 are required to report several data elements that are inputs to the simulation software package that is used to calculate

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[69] American Petroleum Institute (API). *Liquefied Natural Gas (LNG) Operations Consistent Methodology for Estimating Greenhouse Gas Emissions.* Prepared for API by The LEVON Group, LLC. Version 1.0, May 2015. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

emissions. One of the required inputs to report is the solvent weight, in pounds per gallon (40 CFR 98.236(d)(2)(iii)(L)). A variety of different solvents may be used in an acid gas removal unit (*e.g.,* chemical solvents such as monoethanolamine (MEA) and methyl diethanolamine (MDEA), physical solvents such as Selexol™ and Rectisol®), and the solubility of CO_2 varies across the different types of solvent. Requiring reporters to provide solvent characteristics provides information about the type of solvent used so the emissions calculated by the modeling run could be verified. However, the ''solvent weight'' is the only data element related to the identification of the solvent that is currently collected, and the values reported across all reporters have been inconsistent over the last few years, indicating that this data element is likely not clear to reporters (*e.g.,* some reporters appear to be providing the density of the solvent and others appear to be providing the amine concentration in weight percent). In addition, the densities of common amine-based solvents are fairly close in value, so even among reporters that are providing values within the expected range of solvent densities, we have found it difficult to use this data element to identify the solvent type. Finally, the current requirement to report solvent weight does not specify how this value should be determined, but given the precise values being reported, it appears that reporters are either measuring the solvent or reporting a specific value provided by the vendor.

Therefore, we are proposing to replace the requirement to report solvent weight with a requirement to report the solvent type and, for amine-based solvents, the general composition. Reporters would choose the type/general composition option from a pre-defined list that most closely matches the solvent type and composition used in their acid gas removal unit. The standardized response options would include the following: ''Selexol™,'' ''Rectisol®,'' ''Purisol™,'' ''Fluor Solvent℠,'' ''Benfield™,'' ''20 wt% MEA,'' ''30 wt% MEA,'' ''40 wt% MDEA,'' ''50 wt% MDEA,'' and ''Other.'' We are proposing to use commercially available trade names in this list rather than chemical compositions, as the trade names are more commonly used among acid gas removal unit operators and therefore more readily available. This proposed amendment to collect standardized information about the solvent is expected to result in more useful data that would improve verification of reported data and better characterize acid gas removal vent emissions, consistent with section II.A.4 of this preamble. It would also improve the quality of the data reported compared to the apparently inconsistent application of the current requirements. In addition, the solvent type and composition rarely change from one year to the next, so once the data element is reported the first time, most reporters would be able to copy the response from the previous year's reporting form each year. Therefore, the proposal to require reporters to select a solvent type and composition from these standardized responses is also expected to streamline and improve implementation compared to the current requirement of reporting an exact value for solvent weight, consistent with section II.B.3 of this preamble.

d. Dehydrator Vents

Dehydrators are used to remove water from produced natural gas prior to transferring the natural gas into a pipeline or to a gas processing facility. Subpart W requires reporting of GHG emissions from dehydrator vents at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas processing facilities. Emissions are determined using one of the calculation methodologies for glycol dehydrators provided in 40 CFR 98.233(e) based on the unit's annual average daily natural gas throughput. For units with an annual average daily natural gas throughput less than 0.4 MMscf per day, reporters currently use population emission factors and equation W–5 to calculate volumetric CO_2 and CH_4 emissions per 40 CFR 98.233(e)(2). For units with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day, reporters must follow the provisions under 40 CFR 98.233(e)(1), which require modeling GHG emissions using a software program (*e.g.,* AspenTech HYSYS®[70] or GRI–GLYCalc™[71]).

The EPA has reviewed the subpart W glycol dehydrator data and reporting requirements in 40 CFR 98.236(e) and has made a preliminary determination that additional information would help to more accurately characterize emissions from glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day. Specifically, the EPA's review found no strong correlations between glycol dehydrator emissions and the operating parameters currently reported under 40 CFR 98.236(e)(1). This assessment is consistent with the results of an analysis provided to the EPA by GPA Midstream, which indicated that the correlations between vent gas flow rate, glycol circulation rate, and glycol pump type provided the most accurate approximation of dehydrator emissions.[72] While subpart W does currently collect information on glycol pump type and circulation rate for each modeled glycol dehydrator with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day, reporters are not asked to report any characteristics of their units' flash tank and still vents, including vent gas flow rate. As such, the EPA is not able to review historical subpart W dehydrator data to verify GPA Midstream's suggested correlation between vent gas flow rate, glycol circulation rate, and glycol pump type. Therefore, the EPA is proposing to add new reporting requirements to 40 CFR 98.236(e)(1), consistent with section II.A.4 of this preamble. The following new data elements are proposed to be added to subpart W for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day:

- Flash tank control technique
- Regenerator still vent control technique
- Flash tank vent gas flow rate (standard cubic feet per hour (scfh))
- Regenerator still vent gas flow rate (scfh)
- Concentrations of CH_4 and CO_2 in flash tank vent gas (mole fraction)
- Concentrations of CH_4 and CO_2 in regenerator still vent gas (mole fraction)
- Type of stripping gas used
- Flow rate of stripping gas (standard cubic feet per minute (scfm))

These proposed additional data elements are intended to allow the EPA to derive a correlation between vent flow rate and absorbent circulation rate and better characterize emissions from glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day. Further, the EPA is proposing to require separate reporting of emissions for a modeled glycol dehydrator's still vent and flash tank vent. These vents

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[70] AspenTech HYSYS® software available from AspenTech website (*https://www.aspentech.com/*).

[71] GRI–GLYCalc™ software available from Gas Technology Institute website (*https://sales.gastechnology.org/*).

[72] GPA Midstream Association. Presentation slides regarding three alternatives for possible development of emission factors for large glycol dehydrators. November 20, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

often use different control techniques, so requiring the emissions from these vents to be reported separately would ensure that future analyses accurately characterize the emissions. The proposed data elements are included in the output files from the modeling software used for glycol dehydrators and are, therefore, not expected to be difficult for reporters to implement.

Additionally, in correspondence with the EPA via e-GGRT, some reporters have expressed confusion regarding the requirements for glycol dehydrators emissions that are routed to vapor recovery and subsequently routed to a flare or regenerator firebox/fire tubes. As such, the EPA is proposing edits to the vapor recovery calculation methodology of 40 CFR 98.233(e)(5) (proposed to be moved to 40 CFR 98.233(e)(4)) to clarify that unrecovered emissions that are not routed to flares or regenerator fireboxes/fire tubes should be reported as emissions vented directly to atmosphere, while emissions that are routed to flares or regenerator fireboxes/fire tubes should be reported as flared emissions from dehydrators. Along with the proposed amendments to 40 CFR 98.233(e)(6) (proposed to be moved to 40 CFR 98.233(e)(5)) for calculating emissions from flares or regenerator fireboxes/fire tubes (discussed in section III.J.1.i of this preamble), the EPA seeks to enhance the overall quality of the data collected under the GHGRP, consistent with section II.A.5 of this preamble.

e. Liquids Unloading

Subpart W currently requires reporting of emissions from well venting for liquids unloading. Facilities calculate emissions using measured flow rates under Calculation Method 1 (40 CFR 98.233(f)(1)) or engineering equations under Calculation Method 2 for unloadings without plunger lifts (40 CFR 98.233(f)(2)) and Calculation Method 3 for unloadings with plunger lifts (40 CFR 98.233(f)(3)). Under the reporting requirements of 40 CFR 98.236(f), facilities must report whether plunger lifts were used when using Calculation Method 1 and must report the data elements used in equations W–7A and W–7B. For Calculation Methods 2 and 3, however, reporters only report a subset of the data elements used to calculate emissions in equations W–8 and W–9. Specifically, for Calculation Methods 2 and 3, reporters must provide a plunger lift indicator (*i.e.,* whether plunger lifts were used), total number of wells with well venting for liquids unloading, the total number of unloading events, and the casing diameter (Calculation Method 2) or the tubing diameter (Calculation Method 3).

In a 2019 study, Zaimes *et al.*[73] evaluated various liquid unloading scenarios, and the results indicated that differentiating emissions only on the basis of type of unloading (plunger or non-plunger lift) may not accurately assess emissions from this source. In particular, Zaimes *et al.* noted that type of unloading should be further differentiated for plunger lift unloadings between automated and manual unloadings, suggesting further granularity is necessary to properly characterize emissions. In particular, there could be significant differences in the number and duration of unloadings and, hence, differences in emissions between manual and automated plunger lift unloadings and liquids unloading emissions.

The Zaimes *et al.* study did not evaluate manual and automated non-plunger lift unloadings separately, but further differentiating non-plunger lift unloadings between manual and automated unloadings in subpart W could also improve data quality. Correspondence with reporters via e-GGRT since subpart W reporting for the onshore production segment began in 2011 indicates potentially significant differences in the number of unloadings and emissions for manual versus automated non-plunger lift unloadings. When the EPA finalized the calculation methods and reporting requirements for well venting for liquids unloading, the reporting requirements did not differentiate between manual and automated non-plunger lift unloadings. However, reporters have clearly affirmed the use of automated non-plunger lift unloadings in response to multiple inquiries the EPA has made as part of the annual report verification process.

In addition, there are several data elements used to calculate emissions from liquids unloading in equations W–8 and W–9 for Calculation Methods 2 and 3 that are not currently required to be provided. Specifically, reporters do not report well depth (Calculation Method 2) or tubing depth (Calculation Method 3), the average flow-line rate of gas, the hours that wells are left open to the atmosphere during unloading events, and the shut-in, surface or casing pressure (Calculation Method 2) or the flow-line pressure (Calculation Method 3). Requiring reporting of these data elements would improve verification of annual reports to the GHGRP and would allow the EPA and the public to replicate calculations and more confidently confirm reported calculated emissions than is currently possible.

The EPA is, therefore, proposing to revise the reporting requirements in 40 CFR 98.236(f)(1) and (2) to require reporters to include the following data elements, consistent with section II.A.4 of this preamble. In 40 CFR 98.236(f)(1), for Calculation Method 1, the EPA is proposing that reporters would identify the type of unloading as an automated or manual unloading in addition to identifying whether the unloading is a plunger lift or non-plunger lift unloading. We are also proposing that reporters would report emissions from automated unloadings separately from manual unloadings. In addition, for each individual Calculation Method 1 well that was tested during the year, we are proposing that reporters would specify the type of unloading as an automated or manual unloading under 40 CFR 98.236(f)(1)(xi)(F) or 40 CFR 98.236(f)(1)(xii)(F), as applicable.

For non-plunger lift unloadings that use Calculation Method 2 in 40 CFR 98.233(f)(2), the EPA is proposing that reporters would identify the type of non-plunger lift unloading as an automated or manual non-plunger lift unloading and that reporters would report emissions and activity data separately for each unloading type. In addition, for all non-plunger lift unloadings, the EPA is proposing to add requirements in 40 CFR 98.236(f)(2)(ix) (proposed to be moved to 40 CFR 98.236(f)(2)(xi)) to report the average well depth for all wells in the sub-basin (WD_p) and the average shut-in pressure or surface pressure for wells with tubing production, or average casing pressure for wells with no packers for all wells in the sub-basin (SP_p).

For plunger lift unloadings that use Calculation Method 3 in 40 CFR 98.233(f)(3), the EPA is proposing that reporters would identify the type of plunger lift unloading as an automated or manual plunger lift unloading and that reporters would report emissions and activity data separately for each unloading type. In addition, for all plunger lift unloadings, the EPA is proposing to add requirements in 40 CFR 98.236(f)(2)(x) (proposed to be moved to 40 CFR 98.236(f)(2)(xii)) to report the average tubing depth to plunger bumper for all wells in the sub-basin (WD_p) and the average flow-line pressure for all wells in the sub-basin (SP_p). Finally, for all unloadings that use Calculation Method 2 or 3, the EPA is proposing to add requirements in 40

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[73] Zaimes, G.G. *et al.* ''Characterizing Regional Methane Emissions from Natural Gas Liquid Unloading.'' *Environ. Sci. Technol.* 2019, 53, 4619–4629. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

CFR 98.236(f)(2)(ix) and (x) to report the average flow-line rate of gas for all wells in the sub-basin (SFR_p) and cumulative number hours that all wells in the sub-basin are left open to the atmosphere during unloading events ($HR_{p,q}$), respectively.

f. Blowdown Vent Stacks

Subpart W currently requires reporting of blowdowns either using flow meter measurements (40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (40 CFR 98.233(i)(2)). Stakeholders have indicated that there is some confusion regarding the reference to ''distribution'' pipelines in the descriptions of the ''facility piping'' and ''pipeline venting'' categories because compressor stations are not associated with distribution pipelines. Therefore, the EPA is proposing to revise the descriptions of the facility piping and pipeline venting categories to reduce confusion regarding which equipment or event type category is appropriate for each blowdown, consistent with section II.A.5 of this preamble. Our intent is that the ''facility piping'' equipment category is limited to unique physical volumes of piping (*i.e.,* piping between isolation valves) that are located entirely within the facility boundary. Conversely, the intent for the ''pipeline venting'' equipment category is that a portion of the unique physical volume of pipeline is located outside the facility boundary and the remainder, including the blowdown vent stack, is located within the facility boundary. The proposed revisions to the equipment type descriptions would clarify these distinctions. Additionally, we are proposing to remove the reference to ''distribution'' pipelines because we did not intend to limit the pipeline venting category to unique physical volumes that include such pipelines. We agree with the industry stakeholders that facilities subject to the blowdown vent stack reporting requirements typically are connected to other pipelines such as gathering pipelines or transmission pipelines, and on-site blowdowns from sections of these pipelines should be reported. Finally, we note that for the ''facility piping'' equipment category and the ''pipeline venting'' equipment category, the phrase ''located within a facility boundary'' generally refers to being part of the facility as defined by the existing provisions of subpart A or subpart W, as applicable. In other words, blowdowns from unique physical volumes of gathering pipeline that are entirely considered to be part of the ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as defined in 40 CFR 98.238 would be assigned to the ''facility piping'' equipment category. The ''pipeline venting'' equipment category would only apply if the unique physical volume includes some sections of gathering pipelines that are not part of the ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as defined in 40 CFR 98.238.

g. Atmospheric Storage Tanks

Open thief hatches. Facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are required to report CO_2 and CH_4 emissions (and N_2O emissions when flared) from atmospheric pressure fixed roof storage tanks receiving hydrocarbon liquids (hereafter referred to as ''atmospheric storage tanks''). The purpose of a thief hatch on an atmospheric storage tank is generally to allow access to the contents of the tank for sampling, gauging, and determining liquid levels. The thief hatch also works along with the vent valve to maintain pressure on the tank while preventing excessive vacuum from collapsing the tank. The EPA previously evaluated emissions from atmospheric storage tanks as part of the 2016 amendments to subpart W (81 FR 86500, November 30, 2016) and determined that the subpart W calculation methodology in 40 CFR 98.233(j) already includes emissions from thief hatches or other openings on atmospheric storage tanks in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. The subpart W calculation methodologies for controlled atmospheric storage tanks include procedures for determining emissions from storage tanks with a vapor recovery system (40 CFR 98.233(j)(4)) and storage tanks with a flare (40 CFR 98.233(j)(5)). The procedure for determining emissions from a tank with a vapor recovery system instructs reporters to adjust the storage tank emissions downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data (40 CFR 98.233(j)(4)(i)). The procedure for determining emissions from an atmospheric storage tank with a flare references 40 CFR 98.233(n), which instructs reporters to use engineering calculations based on process knowledge, company records, and best available data to determine the flow to the flare if the flare does not have a continuous flow measurement device. If a reporter sees emissions from a thief hatch or other opening on a controlled atmospheric storage tank during an equipment leak survey conducted using OGI, the reporter should consider that information as part of the ''best available data'' used to calculate emissions from that storage tank.

However, it appears that emissions from open thief hatches on atmospheric storage tanks may not be accurately portrayed in subpart W, as many reporters claim 100 percent capture efficiency from vapor recovery systems and flares. In order to alleviate any reporting confusion, the EPA is proposing several clarifying edits to 40 CFR 98.233(j)(4) and (5), consistent with section II.A.5 of this preamble. We are proposing to specifically state in each paragraph that emissions during times of reduced capture efficiency are required to be evaluated to determine if adjustments are needed to the calculated recovered mass from vapor recovery units or flare feed gas volumes. Reduced capture efficiency may occur during periods when the control device is not operating or is bypassed and at times when the control device is operating, such as open thief hatches. The emissions that are not captured by a vapor recovery system or sent to a flare must be considered when calculating emissions from atmospheric storage tanks vented directly to the atmosphere.

The EPA is also proposing revisions to the atmospheric storage tank reporting requirements in 40 CFR 98.236(j) with regard to open thief hatches. Specifically, the EPA is proposing to require reporting of the number of controlled tanks with open or unseated thief hatches within the reporting year, as well as the total volume of gas vented through the open or unseated thief hatches. With these new reporting elements, the EPA seeks to quantify the impact of open thief hatches on atmospheric storage tanks and enhance the overall quality of the data collected under the GHGRP, consistent with section II.A.4 of this preamble.

Malfunctioning dump valves and atmospheric storage tanks with flares. For Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities with atmospheric storage tank emissions calculated using Calculation Method 1 (40 CFR 98.233(j)(1)) or Calculation Method 2 (40 CFR 98.233(j)(2)), reporters must also follow the procedures in 40 CFR 98.233(j)(6) and use equation W–16 to calculate emissions from occurrences of gas-liquid separator dump valves not closing properly. Equation W–16 estimates the annual volumetric GHG emissions at standard conditions from each storage tank resulting from the malfunctioning dump valve on the gas-liquid separator using a correction factor, the total time the dump valve did not close properly in the calendar year, and the hourly storage tank emissions. Per the definition of the variable ''E_n'' in equation W–16, the input hourly storage tank emissions should be those calculated using Calculation Methods 1 or 2 and should be adjusted downward by the magnitude of emissions recovered using a vapor recovery system, if applicable. However, the definition of the variable ''E_n'' in equation W–16 does not include the procedure to be used for emissions from malfunctioning dump valves and atmospheric storage tanks that are flared. In order to address any confusion for reporters, the EPA is proposing to amend the definition of the variable ''E_n'' in equation W–16 to include flared storage tank emissions as determined in paragraph 40 CFR 98.233(j)(5), consistent with section II.A.5 of this preamble. The EPA is also proposing to revise the equation variables (particularly the subscripts) in equation W–16 to clarify the intent of this equation. We are proposing to revise the variable ''E_n'' to ''$E_{s,i}$'' to further clarify that these are the volumetric atmospheric storage tank emissions determined using the procedures in 40 CFR 98.233(j)(1) through (5). We are also proposing to replace the ''n'' and ''p'' subscripts in the other variables with a ''dv'' subscript to indicate that these are the emissions from periods when the gas-liquid separator dump valves were not closed properly and that the emissions from these periods should be added to the emissions determined using the procedures in 40 CFR 98.233(j)(1) through (5).

Composition of hydrocarbon liquids. Under 40 CFR 98.236(j)(1)(vii) and (viii), reporters with atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2 are required to provide the minimum and maximum concentrations (mole fractions) of CO_2 and CH_4 in the tank flash gas. Reporting of emissions and activity data for atmospheric storage tanks is aggregated at the sub-basin or county level, and the minimum and maximum flash gas concentrations were expected to provide the EPA with a broad characterization of the often-significant number of tanks reported for each sub-basin or county. However, through correspondence with reporters via e-GGRT, the EPA has found that the minimum and maximum flash gas concentrations do not accurately represent the majority of atmospheric storage tanks within the reported sub-basins and counties. Thus, the EPA is proposing to revise these two reporting requirements to request the flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in the flash gas, rather than the minimum and maximum values. Consistent with section II.A.4 of this preamble, the EPA expects that these revisions would improve both the representative nature of the data collected and the process of verifying annual reported atmospheric storage tanks emissions data under the GHGRP.

h. Associated Gas Venting and Flaring

Associated gas venting. Associated gas venting or flaring is the venting or flaring of natural gas that originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. Venting associated gas involves directly releasing associated gas into the atmosphere at the well pad or tank battery. Flaring associated gas is a common, and usually preferred, alternative to venting for safety and environmental reasons. Subpart W requires reporters to calculate annual emissions from associated gas venting and flaring using equation W–18, which uses the gas-to-oil ratio (GOR), volume of oil produced, and volume of associated gas sent to sales to calculate the volume of gas vented. Associated gas venting emissions are then calculated using the results of equation W–18 and the gas composition determined using 40 CFR 98.233(u), and associated gas flaring emissions are calculated by applying the calculation method of flare stacks in 40 CFR 98.233(n) to the associated natural gas volume and gas composition determined for the associated gas stream routed to the flare.

As discussed further in section III.J.1.i of this preamble, the EPA is proposing several amendments to the calculation and reporting requirements for flare stacks that would impact associated gas flaring emissions. One of the proposed amendments would provide for the use of continuous flow measurement devices for the purposes of calculating flared emissions. Similarly, for associated gas venting emissions, we are proposing provisions to specify that if a continuous flow measurement device is present, it must be used to determine the volume of gas vented rather than equation W–18. We are proposing corresponding reporting requirements for associated gas venting emissions, including requiring an indication of whether a continuous flow monitor or continuous composition analyzer was used and the flow-weighted mole fractions. Finally, we are proposing to specify that if all of the volumetric emissions from associated gas venting and flaring in the sub-basin were determined using a continuous flow measurement device rather than equation W–18 (*i.e.,* equation W–18 was not used for any wells in the sub-basin), then reporting of the GOR, the volume of oil produced, and the volume of gas sent to sales for wells with associated gas venting or flaring is not required for that sub-basin.

Oil and gas volumes. As noted previously in this section, subpart W requires reporters to calculate annual emissions from associated gas venting and flaring using equation W–18. Two of the inputs in the equation are the volume of oil produced and volume of associated gas sent to sales for each well in the sub-basin during time periods in which associated gas was vented or flared. However, based on the values reported, there seems to be confusion among some reporters regarding the inputs to these equations. For example, for some reporters, when the reported volume of gas sent to sales during time periods in which associated gas was vented or flared under 40 CFR 98.236(m)(6) is summed across all sub-basins at the facility, the total is the same as the total volume of gas sent to sales for the facility reported under 40 CFR 98.236(aa)(1)(i)(B). If these reporters are accurately reporting the volume of gas sent to sales and using that volume in equation W–18, then the associated gas venting and flaring emissions are likely overstated, as it is unlikely that all wells are venting or flaring associated gas 100 percent of the time. If the reporters are using accurate volumes of gas sent to sales during time periods in which associated gas was vented or flared for their emissions calculations but reporting total gas sent to sales, then the activity data reported do not match the emissions, leading to an inconsistent data set. Therefore, the EPA is proposing to add the word ''only'' to the definitions of the terms $V_{p,q}$ and $SG_{p,q}$ in equation W–18 (40 CFR 98.233(m)(3)) and to the reporting requirements for those data elements in 40 CFR 98.236(m)(5) and (6). Consistent with section II.A.5 of this preamble, these proposed amendments would reduce reporter confusion regarding the volumes that should be used in the emissions calculations and the volumes that should be reported.

i. Flare Stack Emissions

Flare stacks are an emission source type subject to emissions reporting by facilities in seven of the ten industry segments in the Petroleum and Natural Gas Systems source category.[74]

Total CO_2, CH_4, and N_2O emissions from each flare are required to be calculated using the methodology specified in 40 CFR 98.233(n). In addition to calculating total emissions from a flare, reporters must also separately calculate the flared emissions from several types of emission sources.[75] The methodology for calculating source-specific flared emissions is specified in the applicable paragraph of 40 CFR 98.233 for each source type. The procedures in the source-specific paragraphs of the rule cross-reference the calculation procedures in 40 CFR 98.233(n), but they also specify that the volume and composition of the gas routed to the flare are required to be determined according to the procedures for estimating vented emissions from the specific source type. For example, 40 CFR 98.233(e)(6) specifies that the volume and gas composition to use in calculating flared emissions from dehydrators must be determined according to the procedures for calculating vented emissions from dehydrators as specified in 40 CFR 98.233(e)(1) through (5). Since source-specific flared emissions often are a portion of the total emissions from a flare, 40 CFR 98.233(n)(9) specifies that the total CO_2, CH_4, and N_2O for a particular flare must be adjusted downward by the amount of the source-specific emissions that are calculated for the same flare; this ensures that emissions from a flare are not double counted (*i.e.,* reported for both the flare stacks source type and another emission source type). The resulting CO_2, CH_4, and N_2O emissions to report for that flare according to 40 CFR 98.236(n)(9) through (11) should be only what is left after subtracting all of the source-specific flared emissions from the total emissions.

This calculation and reporting paradigm often means zero mass emissions are reported for the flare because all of the mass emissions are reported as flared emissions from other source types. However, even when the only streams routed to a flare are from source types that are subject to flared emissions reporting, the flare name or ID and all activity data related to the streams that are routed to the flare and the flare operating characteristics still must be reported under 40 CFR 98.236(n). These activity data include the volume of gas routed to the flare, average CO_2 and CH_4 mole fractions in the flared gas, flare combustion efficiency, fraction of flared gas routed to the flare when it was unlit, and indicators of whether a continuous flow measurement device and a continuous gas analyzer were used on the gas stream routed to the flare. These flare ID and activity data reporting requirements are specified in 40 CFR 98.236(n)(1) through (8). In the rare cases that a CEMS is used on the outlet of a flare, then according to 40 CFR 98.236(n)(12), only the flare ID and the measured CO_2 emissions must be reported.

Reporting requirements for flared emissions. Many reporters have provided information through the GHGRP Help Desk and in correspondence with the EPA via e-GGRT indicating that reporters are not interpreting the reporting requirements as written and as the EPA intended for flares that receive gas from sources that are subject to source-specific flared emissions reporting (*e.g.,* atmospheric tanks). A key misconception is that the adjustment requirement in 40 CFR 98.233(n)(9) applies to all flare data, not just the mass emissions (as intended). Thus, some reporters provide information for a flare only if some of the mass emissions from the flare are due to combustion of gas from source types that are not subject to source-specific flared emissions reporting (*i.e.,* miscellaneous flared sources). Although these reporters generally correctly report the mass emissions from the flare that are due to the miscellaneous flared sources, they incorrectly limit their activity data reporting to those same streams. The EPA has procedures in its verification process to identify such errors; if errors are identified, the EPA notifies the reporter, who can resolve the issue by correcting the data and resubmitting their annual GHG report. Some reporters have also indicated that it is confusing to report activity data for a flare in one table in the reporting form (*i.e.,* Table N.1), but to report the emissions in different tables; they suggest that it would be clearer to report all flare activity data and emissions related to a particular emission source type together in one location. One industry stakeholder, GPA Midstream, also suggested that flare activity data should be reported in the same manner that flared emissions are reported. In other words, instead of providing a single comprehensive record of the activity data per flare as is currently required by 40 CFR 98.236(n), the activity data for flared streams for a particular emission source (*e.g.,* associated gas or atmospheric storage tanks) should be reported with the flared emissions for the same emission source type. According to GPA Midstream, this reporting approach would be simpler and easier for reporters to follow than the current requirements.[76] We reviewed the flare reporting requirements based on this feedback, and we are proposing several revisions to the reporting requirements to improve the quality of the reported data, consistent with section II.A.4 of this preamble.

First, we are proposing to modify the reporting requirements so that the existing requirements in 40 CFR 98.236(n) would apply only to flares that receive gas from miscellaneous flared sources. The activity data to report would be limited to the streams from the miscellaneous flared sources, and the CO_2, CH_4, and N_2O emissions to report would be the emissions that are calculated from combustion of the same streams. In addition, we would add comparable activity data reporting requirements to the reporting required for all of the source types for which flared emissions reporting is currently required (*e.g.,* 40 CFR 98.236(e) for dehydrators, 40 CFR 98.236(g) for completions and workovers with hydraulic fracturing). The activity data reporting would be on the same basis as the emissions reporting. For example, activity data for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day would be related to the flared streams from each dehydrator because flared emissions are reported per dehydrator. Activity data to be

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[74] Flare stacks are an emission source type subject to emissions reporting by facilities in the following industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Import and Export Equipment, and LNG Storage.

[75] Facilities separately calculate the flared emissions from the following types of emission sources (if required for the applicable industry segment, per 40 CFR 98.232): dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, transmission storage tanks, well testing venting and flaring, and associated gas venting and flaring.

[76] Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

reported for associated gas streams, on the other hand, would be aggregated over all associated gas streams routed to flares in a sub-basin because flared associated gas emissions are reported per sub-basin. In addition, for completions and workovers with hydraulic fracturing, flaring during the initial flowback period may not be possible; therefore, some of the wells that report as part of a ''flared'' well type combination because most of the gas is flared may also include emissions from gas that is vented before flaring begins. To improve our understanding of the characteristics of the ''flared'' emissions from completions and workovers with hydraulic fracturing, we are proposing that reporters would indicate in 40 CFR 98.236(g)(10)(i) whether the total emissions reported under 40 CFR 98.236(g)(8) and (9) include emissions from venting during the initial flowback period. These proposed amendments would better align the flared emissions and activity data for source types for which flared emissions reporting is currently required.

Second, in the current rule, 40 CFR 98.236(n)(7) and (8) require reporting of the CH_4 and CO_2 mole fractions in feed gas that are used in equations W–19 and W–20 to calculate total emissions from a flare. The intent was for reporters to provide the average values used to calculate total emissions from the flare. However, the rule language is not clear on this point, and it appears some reporters have interpreted these data elements in different ways. It appears that one common interpretation is to report the mole fraction for the emissions source type with the most flared emissions. Because that interpretation does not align with the EPA's intent, clarification of this reporting requirement is needed to improve the verification process. Thus, we are proposing to modify these reporting elements, both in 40 CFR 98.236(n) (proposed to be moved to 40 CFR 98.236(n)(1)(ix) and (x)) and for all the proposed activity data reporting elements for individual source types that are subject to source-specific flared emissions reporting as described above. Specifically, we are proposing to require the flow-weighted annual average mole fraction of CH_4 over all streams from a particular emission source type that are used in equation W–19 to calculate the reported flared CH_4 emissions from that emission source type (and used in equation W–20 to calculate CO_2 emissions). For example, if a flare receives gas from an acid gas removal vent and a blowdown vent stack, both of which are miscellaneous flared sources, then the CH_4 mole fraction to report should be the flow-weighted annual average value from the acid gas removal vent and each blowdown through the blowdown vent stack. The CO_2 mole fractions to report would also be a flow-weighted annual average determined in the same manner.

Third, reporters are required to use equation W–40 to calculate N_2O emissions from flares. Variables in the equation are the volume of gas routed to the flare and the HHV of the gas. The volume of gas routed to the flare must be reported, but the HHV is not reported. As a result, when reported N_2O emissions differ significantly from the amount that would be expected if using the default HHV, it can be difficult for the EPA to determine whether the reported emissions are an error or if the difference is due to the use of a site-specific HHV. To improve the verification process and potentially reduce the amount of communication with reporters via e-GGRT, we are proposing to add a reporting element that would require reporters to indicate whether each reported N_2O value is based on the default HHV, a site-specific HHV(s), or both the default and site-specific HHVs. The proposed reporting element would be added in 40 CFR 236(n)(4)(iv) for miscellaneous flared sources, and it would be included as one of the proposed activity data reporting elements for each of the other source types that are subject to source-specific flared emissions reporting. Providing an option to indicate that both types of HHVs are used is needed because some reported flared N_2O emissions are aggregated values over all flares in a sub-basin or county (*e.g.,* for atmospheric tanks), and a reporter may choose to use different methods for the flares in each sub-basin or county. In addition to improving the verification process, knowledge of site-specific HHVs would allow the EPA to assess how well the default HHV characterizes flared gas streams in different industry segments and basins.

Fourth, an additional finding from the currently reported data is that a number of facilities in the Onshore Petroleum and Natural Gas Production industry segment, the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, and the Onshore Natural Gas Processing industry segment report significant amounts of emissions from miscellaneous flared sources. It is not clear what sources are generating the large amount of gas that is routed to these flares. To help clarify the source types that are generating large amounts of flared gas, we are proposing in 40 CFR 98.236(n)(1)(v) to require reporting by facilities in these three industry segments of an estimate of the fraction of the gas burned in the flare that is obtained from other facilities specifically for flaring as opposed to being generated in on-site operations. As an example, if an owner or operator has an onshore petroleum and natural gas production and an onshore petroleum and natural gas gathering and boosting facility in the same basin and routes associated gas from wells in the onshore petroleum and natural gas production facility to a flare that is defined as part of the onshore petroleum and natural gas gathering and boosting facility, then the flared emissions would be reported by the onshore petroleum and natural gas gathering and boosting facility as emissions from ''other flare stacks'' sources under the current rule (or from miscellaneous flared sources under the proposed amendments). If the other gas streams routed to the flare are from sources at the onshore petroleum and natural gas gathering and boosting facility, then for this proposed reporting requirement, the onshore petroleum and natural gas gathering and boosting facility report would include an estimate of the fraction of the total gas burned in the flare that is associated gas from the onshore petroleum and natural gas production facility. We request comment on the types of sources that may be generating these large emissions and whether other reporting elements could be specified that would better achieve the EPA's objective of clearly characterizing the sources of flared emissions from facilities in the three industry segments identified above. For example, one potential additional reporting element could be a requirement to describe the primary source of miscellaneous flared emissions for any flare that reports CO_2 emissions greater than an amount that would be determined if such a reporting requirement were finalized.

Finally, one objective of the current flare reporting requirements is to obtain information on the total number of flares and their operating characteristics. If the proposed changes to flare activity data requirements as described previously in this section were finalized, then additional amendments to reporting requirements would be needed to continue collecting flare-specific information. Thus, we are proposing to require reporting of a list of all flare IDs per facility and add reporting for a series of flare-specific data elements. One of the proposed flare reporting elements is the total volume of gas routed to the flare. This information is consistent with current reporting requirements and would be helpful in conducting verification of other reported flare data because the sum of the total volume from all flares should be equal to the sum of the disaggregated volumes reported for all flared emissions source types. The total volumes per flare also would provide information on the range of flare sizes in different industry segments and would be useful in analyses for potential future policy decisions related to flares. Another of the proposed flare reporting elements is a list of the subpart W emission source types that routed emissions to the flare stack. This proposed data element would improve verification of other reported flare data as well as provide information regarding the types of sources that are combined and routed to the same flare. We are also proposing a few new flare-specific reporting elements to help us better understand the state of flaring in the industry, such as an indication of the type of the flare (*e.g.,* open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare) and the type of flare assist (*e.g.,* unassisted, air-assisted (with indication of single-, dual-, or variable-speed fan), steam-assisted, or pressure-assisted). Further, researchers conducting remote sensing tests of emissions from flares have reported detecting much larger quantities of emissions from un-lit flares than is evident from the GHGRP data. To help us better understand the prevalence of emissions from un-lit flares, we are proposing to add requirements to report an indication of whether the flare has a continuous pilot or autoigniter, whether the presence of flame is continuously monitored if the flare has a continuous pilot, and an indication of how the reporter identifies periods when the flare is not lit if the flare does not have a continuous pilot. These proposed data elements would be added in 40 CFR 98.236(n). This paragraph of subpart W would be rearranged into two subparagraphs. The first subparagraph, 40 CFR 98.236(n)(1), would include the current activity data and emissions data reporting elements but would be revised to be specific to miscellaneous flared sources (as discussed previously), and the proposed flare-specific reporting elements would be added in the second subparagraph, 40 CFR 98.236(n)(2).

Definition of flare stack emissions. In response to a verification message in e-GGRT, one reporter noted that the definition of the term ''flare stack emissions'' in 40 CFR 98.238 does not include CO_2 that is in streams routed to the flare. The term is currently defined to mean ''CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.'' Based on this definition, the reporter concluded that CO_2 in streams routed to the flare are not to be reported as flare stack emissions. However, the current definition, which was added to the 2010 Final Revisions Rule after consideration of comments on the 2010 re-proposal, does not clearly convey the EPA's intent that the CO_2 that enters a flare should be reported as flare stack emissions. This intent is evident from the fact that equation W–20 includes a term for the inlet gas volume times the CO_2 mole fraction in the inlet gas. Additionally, in a response to a comment on the 2010 proposed rule, the EPA clearly stated that the total quantity of CO_2, including both combusted CO_2 (*i.e.,* CO_2 created in the flare) and uncombusted CO_2 (*i.e.,* CO_2 that entered and simply passed through the flare), is to be calculated. Another issue with the current definition is that it implies N_2O emissions only result from partial combustion of hydrocarbons in the gas routed to the flare. This is likely the primary mechanism for generating N_2O emissions when combusting fuels that include nitrogen-containing compounds. However, natural gas and field gas have negligible amounts of fuel-bound nitrogen. For combustion of these fuels, it appears the N_2O is generated primarily from converting thermal NO_X under certain operating conditions in the flare. To eliminate the unintended inconsistency between the definition and the intent that CO_2 in gas routed to the flare is to be reported as emissions from the flare, to clarify the requirement to calculate and report total CO_2 that leaves the flare, and to clarify the source of flared N_2O emissions, we are proposing to revise the definition of the term ''flare stack emissions'' to mean CO_2 in gas routed to a flare, CO_2 from partial combustion of hydrocarbons in gas routed to a flare, CH_4 resulting from the incomplete combustion of hydrocarbons in gas routed to a flare, and N_2O resulting from operation of a flare.

Calculation methodology for flared emissions. In addition to proposing changes to the flare reporting requirements as discussed above, we are also proposing to clarify language in the emission calculation procedures of 40 CFR 98.233(n) that we believe may be ambiguous for flares that do not have CEMS, consistent with section II.A.5 of this preamble. The procedures for determining the volume and composition of gas routed to flares for use in the emission calculation equations for a particular emission source type are currently specified in two places for each source type. Each source type-specific paragraph in 40 CFR 98.233 specifies calculation methodologies for that emissions source type, as do 40 CFR 98.233(n)(1) and (2). The procedures in the source type-specific requirements specify only that the volume and composition of the flared gas are to be determined using the procedures for estimating vented emissions from that source type, but they also cross-reference the calculation method in 40 CFR 98.233(n) for determining the emissions from the flaring of that gas stream. However, 40 CFR 98.233(n)(1) and (2) specify that if continuous flow or composition measurement devices are used on the gas to the flare, then data from those devices must be used to calculate emissions; otherwise, estimates may be used. The intent is that the procedures in 40 CFR 98.233(n) should take precedence, but this may not be clear to all reporters. Additionally, the procedures for continuous measurement devices in 40 CFR 98.233(n)(1) and (2) refer to devices ''on the flare'' or ''on gas to the flare.'' The intent is that the procedures should apply to devices regardless of whether they are on a stream routed from a single emission source or on a stream routed to a flare that includes streams combined from multiple emission source types, but this is not explicitly described. A third potential ambiguity is that procedures in 40 CFR 98.233(n)(1) and (2) do not specify how to disaggregate data collected with a continuous measurement device when the device measures a combined stream from more than one emission source type.

To clarify these requirements, we are proposing to specify all of the potential options for determining volume and composition of gas to the flare(s) in the applicable sections of 40 CFR 98.233 for each of the emission source types that have flared emissions reporting requirements. In general, the volume of gas would be determined by a continuous flow measurement device, if available, or using the methods for determining vented emissions for the applicable emission source type. If the measured volume includes flow from multiple source types routed to the same flare, reporters would use process knowledge and best available data to determine the portion of the total flow from each emission source type.[77] Similarly, the composition of the gas from the emission source type would be determined by a continuous composition analyzer, if available, or using the methods for determining the composition of the vented emissions for the applicable emission source type. Alternatively, if multiple source types are routed to one flare and the gas routed to the flare from each of those source types is expected to have similar compositions, the reporter could measure the composition of the total gas to the flare using a continuous composition analyzer just upstream of the flare and apply the results to each of the applicable source types. The source-specific sections of 40 CFR 98.233 would then cross-reference only 40 CFR 98.233(n)(3) through (8) for the applicable calculation equations and procedures for determining combustion efficiency, converting volumetric emissions to mass emissions, and the separate procedures that apply if a CEMS is used on gases from the flare. As part of this proposed amendment, we would also remove 40 CFR 98.233(n)(9); with these proposed calculation methodology clarifications and the reporting clarifications described earlier in this section, a general direction to correct flare emissions to avoid double counting would no longer be necessary (however, a provision specifically to avoid double counting of CO_2 emissions from acid gas removal units that route emissions to a flare would still be needed, as discussed later in this section). We recognize that the proposed changes introduce some repetition to the regulatory text overall because the requirements for each emission source type are similar. However, clearly describing the applicable procedures for each source type separately rather than trying to generally describe a single set of consolidated procedures would make the rule easier for reporters to understand, and we request comment on whether the proposed changes achieve this goal.

Calculation methodologies for flared emissions from acid gas removal vents. We are also proposing source type-specific provisions for calculating and reporting emissions from acid gas removal vents routed to flares that are related to the proposed calculation methodology clarifications described earlier in this section, consistent with section II.A.5 of this preamble. Reporters are currently required to report the CO_2 removed from the natural gas as CO_2 emissions from acid gas removal vents, and that quantity is not affected (*i.e.,* the CO_2 is not converted to another compound) when the acid gas vent stream is routed to a flare, engine, or sulfur recovery plant. Therefore, the current rule does not require reporters to separate emissions vented directly to the atmosphere from emissions routed through a flare, engine, or sulfur recovery plant. Instead, as noted earlier in this section, 40 CFR 98.233(n)(9) specifies that the total CO_2 for a flare that receives gas from acid gas removal vents must be adjusted downward by the amount of the CO_2 emissions that are calculated for those acid gas removal vents. In other words, the CO_2 emissions that are calculated for the acid gas removal vents are reported under 40 CFR 98.236(d) and not under 40 CFR 98.236(n).

Because the reporting of emissions from acid gas removal vents routed to a flare is addressed differently in the current rule from the reporting of flared emissions for all other source types, we are proposing amendments for acid gas removal vents routed to flares that are slightly different than the proposed amendments for other sources. First, as noted previously in this section, we are proposing to remove 40 CFR 98.233(n)(9) because it would be unnecessary for other source types in light of the other amendments previously described. However, for acid gas removal vents routed to flares, an adjustment would still be necessary for CO_2 emissions. Therefore, we are proposing to add provisions in 40 CFR 98.233(d)(12) for calculating emissions from acid gas removal vents routed to flares (as described in more detail in the next paragraph) and proposing to add a clarification to the requirement to report CO_2 emissions from flare stacks (40 CFR 98.236(n)(9), proposed to be moved to 40 CFR 98.236(n)(1)(xi)) indicating that the reported CO_2 emissions should not include emissions from acid gas removal vents reported under 40 CFR 98.236(d)(1)(v) to prevent double counting of emissions.

Second, we reviewed the calculation methods for acid gas removal vents and flares, and we are proposing amendments to more closely align the methods for acid gas removal vents routed to flares. For acid gas removal vents, Calculation Method 1 (40 CFR 98.233(d)(1)) is required to be used if a vent has a CEMS installed, and Calculation Method 2 (40 CFR 98.233(d)(2)) is required to be used if a vent has a continuous flow monitor. If there is no CEMS or flow monitor installed, then reporters currently must use Calculation Methods 3 or 4 (40 CFR 98.233(d)(3) or (4), which are estimation methods based on the volume of natural gas treated and the acid gas contents of the inlet and outlet natural gas. However, because these are estimation methods rather than methods based on measurements, the EPA has found through the verification process and correspondence with reporters via e-GGRT that these methods can sometimes result in estimated volumetric CO_2 emissions from acid gas removal vents routed to a flare that are greater than the reported total volume of gas routed to that flare. Therefore, we are proposing new provisions in 40 CFR 98.233(d)(12) for reporters routing acid gas removal vents to flares. The first set of amendments would apply to acid gas removal vents that are routed to any dedicated flare as well as acid gas removal vents comingled with emissions from other source types and routed to flares with no continuous monitors for either the flow or composition of the comingled gas stream. In either of these cases, reporters would continue to calculate CO_2 emissions using one of the Calculation Methods 1 through 4, as applicable for the type of monitoring available, and would continue to report those emissions under 40 CFR 98.236(d) rather than 40 CFR 98.236(n). Reporters would also incorporate the flow rate and composition of the acid gas removal vent stream into the calculation of total flare emissions from miscellaneous flared sources. For acid gas removal vent streams comingled with emissions from other source types and routed to flares with continuous monitoring of the flow and/or composition of the comingled gas stream, we are proposing that reporters would first determine the total emissions from the flare stacks and then use site-specific engineering estimates based on best available data to estimate the portion of the total flared CO_2 emissions that is from the acid gas removal vents. In this case, we are proposing that reporters would select ‘‘Routed to a flare [§ 98.233(d)(12)(ii)]’’ as the calculation method. We are also proposing new reporting requirements for acid gas removal vents routed to flares; in addition to the current requirements to report the CO_2 emissions under 40 CFR 98.236(d)(1)(v),

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[77] The proposed revisions to 40 CFR 98.233(n)(1) would remove ‘‘company records’’ from the existing list of information upon which engineering calculations may be based. In this instance, the use of ‘‘company records’’ was intended to refer generally to facility records rather than the specific type of records as defined in 40 CFR 98.3, and we expect that general facility records are covered by the proposed inclusion of process knowledge and best available data. Therefore, we are proposing to remove the defined term ‘‘company records’’ solely to avoid confusion for reporters; this amendment is not intended to indicate a change in the engineering calculations.

we are proposing to add the identification of the flare to which the acid gas removal vent is routed.

j. Compressors

Compressors are used across the petroleum and natural gas industry to raise the pressure of and convey natural gas or CO_2. The two main types of compressors used in the industry are centrifugal compressors and reciprocating compressors. Subpart W requires Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities to calculate compressor emissions using population emission factors. Population emission factors are multiplied by the count of equipment, in this case compressors of a certain type, to calculate emissions. For the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment industry segments, subpart W requires facilities to annually measure the emissions from the compressor sources applicable to the mode the compressor is in at the time of the measurement; facilities also have the option to continuously measure emissions from a compressor source. The annual measurements are called ''as found'' measurements because the compressors are to be measured in the mode in which they are found when the measurements are made. The ''as found'' measurements are required for each centrifugal and reciprocating compressor at least annually, but only for those compressor emission sources that have measurement requirements for the mode in which they are found (*i.e.,* the defined ''compressor mode-source combinations''), as described in the following paragraph.

Subpart W defines the following ''compressor sources'': wet seal degassing vent (for centrifugal compressors only); rod packing emissions (for reciprocating compressors only); blowdown valve leakage through the blowdown vent (for both centrifugal and reciprocating compressors) and unit isolation valve leakage through the open blowdown vent without blind flanges (for both centrifugal and reciprocating compressors). Subpart W also defines the following ''compressor modes'': operating-mode (for both centrifugal and reciprocating compressors), standby-pressurized-mode (for reciprocating compressors only [78]), and not-operating-depressurized-mode (for both centrifugal and reciprocating compressors). Some compressor sources may only release emissions during certain compressor modes. Therefore, subpart W uses the term ''compressor mode-source combination'' to refer to the specific compressor sources that must be measured based on the mode in which the compressor is found.

For centrifugal compressors, subpart W requires measurement in the following compressor mode-source combinations: wet seal oil degassing vents in operating-mode, blowdown valve leakage through the blowdown vent in operating-mode, and unit isolation valve leakage through an open blowdown vent without blind flanges in not-operating-depressurized-mode. For reciprocating compressors, subpart W requires measurement in the following compressor mode-source combinations: rod packing emissions in operating-mode, blowdown valve leakage through the blowdown vent in operating-mode, blowdown valve leakage through the blowdown vent in standby-pressurized-mode, and unit isolation valve leakage through an open blowdown vent without blind flanges in not-operating-depressurized-mode.

The EPA is proposing several amendments related to the ''as found'' measurement requirements to improve the quality of data collected for compressors. First, standby-pressurized-mode was not included as a mode for centrifugal compressors in the subpart W definition of ''compressor mode'' and no compressor mode-source combinations were defined for centrifugal compressors in standby-pressurized-mode. While centrifugal compressors are seldom in the standby-pressurized-mode, there have been several occasions when reporters have indicated through the GHGRP Help Desk that a centrifugal compressor was in this mode during the ''as found'' measurement. This has led to confusion from reporters regarding how to report the data from the measurements performed. To address this issue, we are proposing to add standby-pressurized-mode to the defined modes for centrifugal compressors (40 CFR 98.238) and require measurement of volumetric emissions from the wet seal oil degassing vent and volumetric emissions from blowdown valve leakage through the blowdown vent when the compressor is found in this mode (40 CFR 98.233(o)(1)(i)(C) as proposed), consistent with sections II.A.2 and II.A.5 of this preamble.

Second, dry seals on centrifugal compressors were not included in the subpart W definition of ''compressor source'' and no compressor mode-source combinations were defined for dry seals on centrifugal compressors. While emissions from wet seal oil degassing vents are expected to be larger than from dry seals, dry seals may still contribute to centrifugal compressor emissions. Additionally, the measurement crew will already be at the centrifugal compressor to make the ''as found'' measurement for blowdown valve leakage. Therefore, to better characterize the emissions from dry seal centrifugal compressors, we are proposing to add dry seal vents to the defined compressor sources for centrifugal compressors (40 CFR 98.238) and require measurement of volumetric emissions from the dry seal vents in both operating-mode and in standby-pressurized-mode (40 CFR 98.233(o)(2)(iii) as proposed), consistent with section II.A.2 of this preamble. Proposed measurement methods for the dry seal vents are similar to those provided for reciprocating compressor rod packing emissions and would include the use of temporary or permanent flow meters, calibrated bags, and high volume samplers. Screening methods may also be used to determine if a quantitative measurement is required. Acoustical screening or measurement methods are not applicable to dry seal vents because these emissions are not a result of through-valve leakage. These proposed revisions include a proposed new reporting requirement to report the number of dry seals on centrifugal compressors and the reporting of emission measurements made on the dry seals.

Third, we are proposing to revise 40 CFR 98.233(p)(1)(i) to require measurement of rod packing emissions for reciprocating compressors when found in the standby-pressurized-mode because recent studies indicate that rod packing emissions can occur while the compressor is in this mode.[79] The inclusion of this compressor mode-source combination would more accurately reflect compressor emissions, consistent with section II.A.2 of this preamble. Furthermore, the measurement crew will already be at the compressor to make the ''as found''

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[78] Currently, subpart W does not require measurements for centrifugal compressors in standby-pressurized-mode and therefore does not define this mode for centrifugal compressors.

[79] Subramanian, R. *et al.* ''Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol.'' *Environ. Sci. Technol.* 49, 3252–3261. 2015. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

measurement for blowdown valve leakage and several reporters already make these measurements.

Fourth, we are proposing to revise the allowable methods for measuring wet seal oil degassing vents. Since the inception of subpart W, the only method provided in 40 CFR 98.233(o)(2)(ii) for measuring volumetric flow from wet seal oil degassing vents has been the use of a temporary or permanent flow meter. The limitation in methods allowed for wet seal oil degassing vents was due to the expectation that the volumetric flows may exceed the quantitative limits of these other methods. In reviewing the data reported for the wet seal oil degassing vent, we found that the measured flow rates using flow meters are often within the limits of other measurement methods allowed for other compressor sources. We also found that many reporters have overlooked the restriction on the methods allowed for wet seal oil degassing vents and often reported using other measurement methods (*e.g.,* high volume samplers). We have found that most of these measured flow rates appear to be within the capacity limits of a typical high volume sampler. In the small minority of cases in which flow rates would be outside of the capacity limit of the instrument, facilities can use an alternate method, consistent with the requirements for other compressor source measurements. Consequently, we concluded that the measurement methods allowed for wet seal oil degassing vents could be expanded to include the use of calibrated bags and high volume samplers. Therefore, we are proposing to revise 40 CFR 98.233(o)(2)(ii) to allow the use of calibrated bags and high volume samplers. However, we are not proposing to allow the use of screening methods because wet seal oil degassing vents are expected to always have some natural gas flow. Therefore, we are proposing to retain and clarify this unique limitation on the use of screening methods for wet seal oil degassing vent measurement methods. This proposed revision would provide greater flexibility and improved clarity of the wet seal oil degassing provisions consistent with section II.A.2 of this preamble.

Fifth, we are proposing to remove acoustic leak detection from the screening and measurement methods allowed for manifolded groups of compressor sources. As noted in 40 CFR 98.234(a)(5), acoustic leak detection is applicable only for through-valve leakage. The acoustic method can be applied to individual compressor sources associated with through-valve leakage (*i.e.,* blowdown valve leakage or isolation valve leakage), but it cannot be applied to a vent that contains a group of manifolded compressor sources downstream from the individual valves or other sources that may be manifolded together. The inclusion of this method for manifolded compressor sources was in error and we are proposing to remove it from 40 CFR 98.233(o)(4)(ii)(D) and (E) and 40 CFR 98.233(p)(4)(ii)(D) and (E) to improve accuracy of the measurements, consistent with section II.A.2 of this preamble.

Sixth, we are proposing a number of clarifications to the references to the allowed measurement methods to correct errors and improve the clarity of the rule, consistent with section II.A.5 of this preamble. These proposed revisions include: revising 40 CFR 98.233(o)(1)(i)(A) and (B) to reference 40 CFR 98.233(o)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements; revising 40 CFR 98.233(p)(1)(i)(A), (B) and (C) to reference 40 CFR 98.233(p)(2)(i) instead of specific subparagraphs of that paragraph that may be construed to limit the methods allowed for blowdown or isolation valve leakage measurements; revising 40 CFR 98.233(p)(1)(i)(A) and (C) (as proposed) to reference ''paragraph (p)(2)(ii) or (iii) of this section as applicable'' instead of only ''paragraph (p)(2)(ii)'' to clarify that measurement of rod packing emissions without an open-ended vent line are to be made according to 40 CFR 98.233(p)(2)(iii); and revising 40 CFR 98.233(p)(2)(ii)(C) and (iii)(A) to clarify that acoustic leak detection is not an applicable screening method for rod packing emissions (not a through-valve leakage).

In addition to these proposed revisions to the ''as found'' measurement requirements, we are also proposing to clarify the language at 40 CFR 98.233(o)(10) and (p)(10) for compressors at Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting facilities, consistent with section II.A.2 of this preamble. The compressor emission factors for these industry segments are specific to uncontrolled wet seal oil degassing vents on centrifugal compressors and uncontrolled rod packing emissions for reciprocating compressors. The language in 40 CFR 98.233(o) and (p) clearly indicates that the provisions of 40 CFR 98.233(o)(10) and (p)(10) do not apply for controlled compressor sources. However, proposed revisions are necessary to provide clarity regarding the compressor sources for which emissions are required to be calculated under 40 CFR 98.233(o)(10) and (p)(10) and reported under 40 CFR 98.236(o)(5) and (p)(5). Specifically, we are proposing minor revisions to 40 CFR 98.233(o)(10) and the corresponding reporting requirements in 40 CFR 98.236(o)(5) to clarify that the compressor count used in equation W–25 should be the number of centrifugal compressors with atmospheric (*i.e.,* uncontrolled) wet seal oil degassing vents. Similarly, we are proposing minor revisions to 40 CFR 98.233(p)(10) and the corresponding reporting requirements in 40 CFR 98.236(p)(5) to clarify that the compressor count used in equation W–29D should be the number of reciprocating compressors with atmospheric (*i.e.,* uncontrolled) rod packing emissions. Finally, we are proposing to add requirements to report the total number of centrifugal compressors at the facility and the number of centrifugal compressors that have wet seals to 40 CFR 98.236(o)(5) and proposing to add a requirement to report the total number of reciprocating compressors at the facility to 40 CFR 98.236(p)(5). These additional data would provide the EPA with an improved understanding of the total number of compressors and the number of compressors that are controlled (*i.e.,* routed to flares, combustion, or vapor recovery systems) in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, consistent with section II.A.4 of this preamble.

k. Equipment Leak Surveys

Addition of leaker emission factors for survey methods other than method 21. Subpart W reporters are required to quantify emissions from equipment leaks using the calculation methods in 40 CFR 98.233(q) (equipment leak surveys) and/or 40 CFR 98.233(r) (equipment leaks by population count). The equipment leak survey method uses the count of leakers detected with one of the subpart W leak detection methods in 40 CFR 98.234(a), subpart W leaker emission factors, and operating time to estimate the emissions from equipment leaks. The current leaker emission factors applicable to onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities are found in Table W–1E of subpart W. These leaker emission factors are based on the EPA's *Protocol for Equipment Leak Emission Estimates* published in 1995 (Docket Id. No. EPA–HQ–OAR–2009–0927–0043), also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. The leaker emission factors are provided for components in gas service, light crude service, and heavy crude service that are found to be leaking via several different screening methods. In addition to being component- and service-specific, subpart W currently provides two different sets of leaker emission factors: one based on leak rates for leaks identified by Method 21 (see 40 CFR part 60, appendix A–7) using a leak definition of 10,000 ppm and one based on leak rates for leaks identified by Method 21 using a leak definition of 500 ppm. Currently, the other leak screening methods provided in subpart W (OGI, infrared laser beam illuminated instrument, and acoustic leak detection device) use the leaker emission factors based on Method 21 data with a leak definition of 10,000 ppm.

In the years that have followed the adoption of these emission factors into subpart W, there have been numerous studies regarding emissions from equipment leaks that provide measurement data to quantify leaker emission factors for OGI screening methods at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.[80] These studies found that OGI identifies fewer yet larger leaks than the EPA's Method 21. Specifically, the average leaker emission factor determined from OGI leak detection surveys is often a factor of two or more larger than leaker emission factors determined when using Method 21 leak detection surveys. Therefore, the application of the same leaker emission factor to leaking components detected with OGI and Method 21 with a leak definition of 10,000 ppm, as is currently done in subpart W, likely understates the emissions from leakers detected with OGI.

Based on our review of these studies, we are proposing to amend the leaker emission factors in Table W–1E for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities to include separate emission factors for leakers detected with OGI, consistent with section II.A.1 of this preamble. These emission factors were developed by combining the data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) to provide OGI leaker emission factors by site type (*i.e.,* gas or oil). These studies were selected as the basis for the proposed OGI emission factors because they included recent measurements of subpart W-specified equipment leak components from both oil and gas production and gathering and boosting sites in geographically diverse locations. The precise derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

At onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, very few facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys and there are no data available to develop leaker emission factors specific to these methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using the proposed OGI leaker factors. Therefore, we are proposing that, if these alternative methods are used to conduct leak surveys, the proposed OGI leaker emission factors would be used to quantify the emissions from the leaks identified using these other monitoring methods.

For onshore petroleum and natural gas gathering and boosting facilities, all components are considered to be in gas service consistent with the language in 40 CFR 98.233(q)(2)(iv); thus, the gas service factors from Table W–1E should be applied to all leakers. In order to make clear how onshore petroleum and natural gas production facilities should apply these revised emission factors, we are proposing to amend 40 CFR 98.233(q)(2)(iii) to state that onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors consistent with the well type, where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in Table W–1E to this subpart.

As described previously, our analysis of measurement study data from onshore production and gathering and boosting facilities demonstrates that the OGI screening method finds fewer and larger leaks than Method 21. Consequently, the leaker emission factors derived using measurement data from the OGI screening method are larger than those derived using the measurement data from Method 21 screening method. We expect that the leaker emission factors for other industry segments that are based on measurements of Method 21-identified leaks may similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks. Therefore, we are proposing to apply the ''OGI enhancement'' factor identified from measurement study data in the onshore production and gathering and boosting industry segments to the leaker emission factors for the other subpart W industry segments as a means to estimate an OGI emission factor set. Analogous to the proposed changes in Table W–1E for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, this results in the addition of an emission factor set specific to OGI, infrared laser beam illuminated instrument, or acoustic leak detection device screening methods. The proposed emission factor sets are included in Tables W–2A, W–3A, W–4A, W–5A, W–6A, and W–7 for the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import and Export Equipment, and Natural Gas Distribution industry segments, respectively. A detailed description of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

As an alternative to the proposed revised default leaker emission factors, we are also proposing an option that would allow reporters to quantify emissions from equipment leak components in 40 CFR 98.233(q) by performing direct measurement of equipment leaks and calculating emissions using those measurement results, consistent with section II.A.2 of this preamble. The proposed amendments would provide that

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[80] See, *e.g.,* ERG (Eastern Research Group, Inc.) and Sage (Sage Environmental Consulting, LP). *City of Fort Worth Natural Gas Air Quality Study: Final Report.* July 13, 2011, available at *https://www.fortworthtexas.gov/departments/development-services/gaswells/air-quality-study/final;* Allen, D.T., *et al.* ''Measurements of methane emissions at natural gas production sites in the United States.'' *Proceedings of the National Academy of Sciences of the United States of America,* Vol. 110, no. 44. pp. 17768–17773, October 29, 2013, available at *http://dept.ceer.utexas.edu/methane/study.* Docket Item No. EPA–HQ–OAR–2014–0831–0006; Pacsi, A.P., *et al.* ''Equipment leak detection and quantification at 67 oil and gas sites in the Western United States.'' *Elem Sci Anth,* 7: 29, available at *https://doi.org/10.1525/elementa.368.* 2019; Zimmerle, D., *et al.* ''Methane Emissions from Gathering Compressor stations in the U.S.'' *Environmental Science & Technology* 2020, 54(12), 7552–7561, available at *https://doi.org/10.1021/acs.est.0c00516.* The documents are also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

facilities with components subject to 40 CFR 98.233(q) can elect to perform direct measurement of leaks using one of the subpart W measurement methods in 40 CFR 98.234(b) through (d) such as calibrated bagging or a high volume sampler. To use this proposed option, all leaks identified during a ''complete leak detection survey'' must be quantified; in other words, reporters could not use leaker emission factors for some leaks and quantify other leaks identified during the same leak detection survey. For the Onshore Petroleum and Natural Gas Production industry segment, a complete leak detection survey would be the fugitive emissions monitoring of a well site conducted to comply with NSPS OOOOa, NSPS OOOOb, or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62 or, if the reporter elected to conduct the leak detection survey, a complete survey of all equipment on a single well-pad. For the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, a complete leak detection survey would be the fugitive emissions monitoring of a compressor station to comply with NSPS OOOOa, NSPS OOOOb, or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62 or, if the reporter elected to conduct the leak detection survey, a complete survey of all equipment at a gathering ''compressor station'' or at a ''centralized oil production site'' (and we are proposing to define these terms in 40 CFR 98.238, as described in section III.J.1.p of this preamble). For downstream industry segments (*e.g.,* Onshore Natural Gas Transmission Compression), a complete leak detection survey is facility-wide, and therefore, the election to perform direct measurement of leaks would also be facility-wide. In other words, this option would allow the use of measurement data directly when all leaks identified are quantitatively measured.

The proposed amendments rely specifically on quantitative measurement methods already provided in the rule. We are seeking comment on alternative methods for quantifying leaks for use for these equipment leak measurements (and for ''as found'' compressor measurements) along with supporting information and data. The supporting information should include description of the method, limitations on the applicability of the method, and calibration requirements. Supporting data should include accuracy assessments relative to other quantitative measurement methods provided in the rule.

Finally, as part of this overall amendment, we are also proposing to remove the additional Method 21 screening when a survey is conducted using a method other than Method 21. Currently, facilities using survey methods other than Method 21 to detect equipment leaks may then screen the equipment identified as leaking using Method 21 to determine if the leak measures greater than 10,000 parts per million by volume (ppmv) (see, *e.g.,* 40 CFR 98.234(a)(1)). If the Method 21 screening of the leaking equipment is less than 10,000 ppmv, then reporters may consider that equipment as not leaking. In the 2016 subpart W revisions, we added a leak detection methodology at 40 CFR 98.234(a)(6) (proposed to be moved to 40 CFR 98.234(a)(1)(ii)) for using OGI in accordance with NSPS OOOOa, which does not include an option for additional Method 21 screening. As noted in response to comments on the subpart W proposal regarding the absence of this optional additional Method 21 screening when using OGI in accordance with NSPS OOOOa, the additional screening of OGI-identified leaking equipment using Method 21 requires additional effort from reporters (81 FR 86500, November 30, 2016). Furthermore, as noted previously in this section, the average emissions of leakers identified by OGI are greater than leaks identified by Method 21. Directly applying the number of OGI-identified leaks to the subpart W leaker emission factor specific to that survey method would provide the most accurate estimate of emissions, while selectively screening OGI-identified leaks using Method 21 to reduce the number of reportable leakers would yield a low bias in the reported emissions. Therefore, we are proposing to require reporters to directly use the leak survey results for the monitoring method used to conduct the complete leak survey and are proposing to eliminate this additional Method 21 screening provision. In addition to providing more accurate emissions data consistent with section II.A.2 of this preamble, the removal of the additional monitoring step would streamline and improve implementation consistent with section II.B.2 of this preamble.

Amendments related to oil and natural gas standards and emissions guidelines in 40 CFR part 60. As noted in the introduction to section III.J of this preamble, the EPA recently proposed NSPS OOOOb and EG OOOOc for oil and natural gas new and existing affected sources, respectively. Under the proposed standards in NSPS OOOOb and the proposed presumptive standards in EG OOOOc, owners and operators would be required to implement a fugitive emissions monitoring and repair program for the collection of fugitive emissions components at well site and compressor station affected sources. In addition, the proposed NSPS OOOOb and EG OOOOc include a proposed appendix K to 40 CFR part 60, an OGI-based method for detecting leaks and fugitive emissions from all components that is not currently provided in subpart W. The EPA also proposed provisions in NSPS OOOOb and EG OOOOc for equipment leak detection and repair at onshore natural gas processing facilities. Similar to the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA is proposing to revise the calculation methodology for equipment leaks in subpart W so that data derived from equipment leak and fugitive emissions monitoring conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would be used to calculate emissions, consistent with section II.A.2 of this preamble.

First, under these proposed amendments, facilities with certain fugitive emissions components at a well site or compressor station subject to NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 would use the data derived from the NSPS OOOOb or 40 CFR part 62 fugitive emissions requirements along with the subpart W equipment leak survey calculation methodology and leaker emission factors to calculate and report their GHG emissions to the GHGRP. Specifically, the proposed amendments would expand the cross-reference to 40 CFR 60.5397a to include the analogous requirements in NSPS OOOOb or 40 CFR part 62. Facilities with fugitive emissions components not subject to the standards in the proposed NSPS OOOOb or addressed by the presumptive standards in the proposed EG OOOOc and subject to 40 CFR part 62 would continue to be able to elect to calculate subpart W equipment leak emissions using the leak survey calculation methodology and leaker emission factors (as is currently provided in 40 CFR 98.233(q)). Therefore, reporters with other fugitive emission sources at subpart W facilities not covered by NSPS OOOOb or 40 CFR part 62 (*e.g.,* sources subject to other state regulations and sources participating in the Methane Challenge Program or other voluntarily implemented programs) would continue to have the opportunity to voluntarily use the proposed leak detection methods to calculate and report their GHG emissions to the GHGRP. To facilitate this proposed requirement, we are also proposing to clarify that fugitive emissions monitoring conducted to comply with NSPS OOOOa, NSPS OOOOb, or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 is considered a ''complete leak detection survey,'' so that onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities can use NSPS OOOOb or 40 CFR part 62 fugitive emission surveys directly for their subpart W reports. In a corresponding amendment, we are also proposing to expand the current reporting requirement in 40 CFR 98.236(q)(1)(iii) to require reporters to indicate if any of the surveys of well sites or compressor stations used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the fugitive emissions standards in NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62.[81] We request comment on these proposed amendments and whether there are other provisions or reporting requirements relative to NSPS OOOOb or EG OOOOc that we should consider for subpart W.

Second, we are proposing to revise 40 CFR 98.234(a) to clarify and consolidate the requirements for OGI and Method 21 in 40 CFR 98.234(a)(1) and (2), respectively. In the 2016 amendments to subpart W (81 FR 4987, January 29, 2016), the EPA added 40 CFR 98.234(a)(6) and (7) to provide OGI and Method 21 as specified in NSPS OOOOa as leak detection survey methods. In part, structuring the amendment this way allowed the EPA to provide the NSPS OOOOa leak detection methods as allowable methods under subpart W without affecting the requirements for facilities and industry segments not subject to NSPS OOOOa. However, as the EPA continues to propose additional standards with slightly different variations on OGI and Method 21, it would be unnecessarily convoluted to continue to add those methods and cross-references to each standard to the end of 40 CFR 98.234(a). Therefore, the EPA is proposing to move 40 CFR 98.234(a)(1) and 40 CFR 98.234(a)(6) to 40 CFR 98.234(a)(1)(i) and 40 CFR 98.234(a)(1)(ii), respectively, which would consolidate the OGI-based methods in 40 CFR 98.234(a)(1). Similarly, the EPA is proposing to revise 40 CFR 98.234(a)(2) such that 40 CFR 98.234(a)(2)(i) is Method 21 with a leak definition of 10,000 ppm and 40 CFR 98.234(a)(2)(ii) is Method 21 with a leak definition of 500 ppm. This proposed amendment would effectively move 40 CFR 98.234(a)(7) to 40 CFR 98.234(a)(2)(ii). The references to ''components listed in § 98.232'' would be replaced with a more specific reference to 40 CFR 98.233(q)(1). The references to specific provisions in 40 CFR 60.5397a in 40 CFR 98.234(a)(6) and (7) would be moved to 40 CFR 98.234(a)(1)(ii) and 40 CFR 98.234(a)(2), as applicable.

The EPA proposed in NSPS OOOOb and EG OOOOc that owners and operators would detect leaks using an OGI-based monitoring method following the concurrently proposed appendix K to 40 CFR part 60. We are proposing to include that same method in subpart W at 40 CFR 98.234(a)(1)(iii) to ensure that reporters would be able to comply with the proposed subpart W requirement to use data derived from the NSPS OOOOb or 40 CFR part 62 fugitive emissions requirements for purposes of calculating emissions from equipment leaks. As part of the proposal of NSPS OOOOb and EG OOOOc, the EPA proposed an alternative screening approach for fugitive emissions from well sites and compressor stations that would allow the use of advanced measurement technologies to detect large equipment leaks. If emissions are detected using one of these advanced technologies, facilities would be required to conduct monitoring using OGI or Method 21 to identify and repair specific leaking equipment. Additionally, even if no large emissions are identified, facilities using these advanced technologies would still be required to conduct annual fugitive emissions monitoring using OGI or Method 21. The EPA's intent in this proposed rule for subpart W is that the results of those NSPS OOOOb and 40 CFR part 62 OGI or Method 21 surveys would be used for purposes of calculating emissions for subpart W, as OGI and Method 21 are capable of identifying leaks from individual components and they are leak detection methods provided in subpart W. The EPA also requests comment on additional methods or advanced technologies that can identify individual leaking components. Based on the information received, the EPA would need to review the specific method and leak detection data collected using that method to determine what default leaker emission factors would apply for that method and whether any adjustments might be needed to the subpart W equipment leak survey calculation methodology when using that method. Following that review, the EPA may undertake a rulemaking process to include the additional leak detection method(s) in 40 CFR 98.234(a).

Third, we are proposing subpart W requirements for onshore natural gas processing facilities consistent with certain requirements for equipment leaks in the proposed NSPS OOOOb or EG OOOOc. Currently, onshore natural gas processing facilities must conduct at least one complete survey of all the components listed in 40 CFR 98.232(d)(7) each year, and each complete survey must be considered when calculating emissions according to 40 CFR 98.233(q)(2). Under the equipment leak detection and repair program included in proposed NSPS OOOOb and the EG OOOOc presumptive standards, different component types may be monitored on different frequencies, so all equipment at the facility is not always monitored at the same time. According to the current requirements in 40 CFR 98.233(q), surveys that do not include all of the applicable equipment at the facility are not considered complete surveys and are not used for purposes of calculating emissions. Therefore, we are proposing that for onshore natural gas processing facilities subject to NSPS OOOOb or an applicable approved state plan or the applicable Federal plan in 40 CFR part 62 would use the data derived from each equipment leak survey conducted as required by NSPS OOOOb or 40 CFR part 62 along with the subpart W equipment leak survey calculation methodology and leaker emission factors to calculate and report GHG emissions to the GHGRP, even if a survey required for compliance with NSPS OOOOb or 40 CFR part 62 does not include all the component types listed in 40 CFR 98.232(d)(7).

Under this proposed amendment, reporters would still have to meet the subpart W requirement to conduct at least one complete survey of all applicable equipment at the facility per year, so if there were components listed in 40 CFR 98.232(d)(7) not included in any NSPS OOOOb or 40 CFR part 62-required surveys conducted during the year (*e.g.,* connectors that are monitored only once every 4 years), reporters

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[81] We are similarly proposing to revise the existing reporting requirement related to NSPS OOOOa, such that reporters would report whether any of the surveys of well sites or compressor stations used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the fugitive emissions standards in NSPS OOOOa (rather than simply reporting whether the facility has well sites or compressor stations subject to the fugitive emissions standards in NSPS OOOOa).

subject to NSPS OOOOb or 40 CFR part 62 would need to either add those components to one of their required surveys, making that a complete survey for purposes of subpart W, or conduct a separate complete survey for purposes of subpart W. We expect that reporters with onshore natural gas processing plants implementing traditional leak detection and repair programs are already making similar decisions regarding how to meet the requirement to conduct a complete survey for subpart W, and our intention with this proposed amendment is not to change those decisions. Rather, this amendment would specify that surveys conducted pursuant to NSPS OOOOb or 40 CFR part 62 that do not include all component types listed in 40 CFR 98.232(d)(7) would be used for calculating emissions along with each complete survey.

We are also proposing to add leaker emission factors for all survey methods for ''other'' components that would be required to be monitored under NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62 or that reporters elect to survey that are not currently included in subpart W. These proposed total hydrocarbon leaker emission factors are the same as the total hydrocarbon leaker emission factors for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (Table W–3A and Table W–4A, respectively). For more information on the derivation of the original emission factors, see the TSD for the final subpart W standards,[82] and for more information on the derivation of the emission factors proposed to be added to Table W–2B, see the TSD for the 2016 amendments to subpart W.[83] In a corresponding amendment, we are also proposing to expand the reporting requirement in 40 CFR 98.236(q)(1)(iii) to require onshore natural gas processing reporters to indicate if any of the surveys used in calculating emissions under 40 CFR 98.233(q) were conducted to comply with the equipment leak standards in NSPS OOOOb or an applicable approved state plan or the applicable Federal plan in 40 CFR part 62. We request comment on the proposed amendments to subpart W for onshore natural gas processing facilities subject to the equipment leak provisions of NSPS OOOOb or 40 CFR part 62, as well as whether there are other provisions or reporting requirements for these facilities that we should consider.

Finally, in our review of subpart W equipment leak requirements for onshore natural gas processing facilities, we found that the leak definition for the Method 21-based requirements for processing plants in NSPS OOOOa (as well as proposed NSPS OOOOb and EG OOOOc presumptive standards) is not consistent with the leak definition in the Method 21 option in current 40 CFR 98.234(a)(1), which is the only Method 21-based method available to onshore natural gas processing facilities under subpart W. Based on this review, and to complement the proposed addition of default leaker emission factors for survey methods other than Method 21 (as described previously in this preamble), we are proposing several additions to the equipment leak survey requirements for the Onshore Natural Gas Processing industry segment, beyond those amendments already described related to the proposed NSPS OOOOb and EG OOOOc presumptive standards. First, we are proposing default leaker emission factors for Method 21 at a leak definition of 500 ppm in Table W–2A. As with the proposed ''other'' leaker emission factors, these proposed leaker emission factors are the same as the total hydrocarbon leaker emission factors for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (Table W–3A and Table W–4A, respectively). For more information on the derivation of those emission factors, see the TSD for the 2016 amendments to subpart W.[84] In addition, we are proposing to add 40 CFR 98.233(q)(1)(v) to indicate that onshore natural gas processing facilities not subject to NSPS OOOOb or an approved state plan or the applicable Federal plan in 40 CFR part 62 may use any method specified in 40 CFR 98.234(a), including Method 21 with a leak definition of 500 ppm and OGI following the provisions of appendix K to 40 CFR part 60. This proposed amendment would ensure that equipment leak surveys conducted using any of the approved methods in subpart W would be available for purposes of calculating emissions, not just those surveys conducted using one of the methods currently provided in 40 CFR 98.234(a)(1) through (5).

l. Equipment Leaks by Population Count

As noted in section III.J.1.k of this preamble, subpart W reporters are required to quantify emissions from equipment leaks using the calculation methods in 40 CFR 98.233(q) (equipment leak surveys) and/or 40 CFR 98.233(r) (equipment leaks by population count), depending upon the industry segment. The equipment leaks by population count method uses the count of equipment components, subpart W emission factors (*e.g.,* Table W–1A for the Onshore Petroleum and Natural Gas Production industry segment), and operating time to estimate emissions from equipment leaks. For the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, the count of equipment components may be determined by counting each component individually for each facility (Component Count Method 2) or the count of equipment components may be estimated using the count of major equipment and subpart W default average component counts for major equipment (Component Count Method 1) in Tables W–1B and W–1C, as applicable. Reporters in other industry segments must count each applicable component at the facility. We are proposing several amendments to the calculation methodology provisions of 40 CFR 98.233(r) and the reporting requirements in 40 CFR 98.236(r) to improve the quality of the data collected, consistent with sections II.A.1, II.A.4, and II.A.5 of this preamble.

Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting population count method. The current population emission factors for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are found in Table W–1A of subpart W. The gas service population emission factors are based on the 1996 Gas Research Institute (GRI)/EPA study *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks* (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). The oil service population emission factors are based on the American Petroleum Institute's (API) Emission Factors for Oil

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[82] *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Systems Industry: Background Technical Support.* November 2010. Docket Id. No. EPA–HQ–OAR–2009–0923–3610; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[83] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems.* November 1, 2016. Docket Id. No. EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[84] *Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems.* November 1, 2016. Docket Id. No EPA–HQ–OAR–2015–0764–0066; also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

and Gas Production Operations, Publication 4615 published in 1995.

As noted previously in this section, when estimating emissions using the population count method, onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities have the option to use actual component counts (*i.e.,* Component Count Method 2) or to estimate their component counts using the count of major equipment (*e.g.,* wellhead) and default component counts per major equipment (*e.g.,* valves per wellhead) included in Tables W–1B and W–1C of subpart W (*i.e.,* Component Count Method 1). In reviewing subpart W data, we find that the vast majority (greater than 95 percent) of onshore production and natural gas gathering and boosting facilities use Component Count Method 1 to estimate the count of components.

It is important to note that both the population count emission factors and the default component counts per major equipment included in Tables W–1A, W–1B and W–1C are service-specific (*i.e.,* gas or oil) as well as region-specific (*i.e.,* eastern or western U.S.). The regional designations are provided by U.S. state in Table W–1D of subpart W such that a facility would determine the facility's region and select the appropriate region- and service-specific factors.

In the years that have followed the adoption of these emission factors into subpart W, there have been numerous studies regarding emissions from equipment leaks at onshore production and gathering and boosting facilities. Two recent field studies, Pacsi *et al.* (2019)[85] and Zimmerle *et al.* (2020),[86] have performed an equipment and component inventory alongside equipment leak screening and measurement results. Another recent study, Rutherford *et al.* (2021),[87] included synthesis and analysis of measurements from component-level field studies. These studies provide the necessary data to develop and compare study-estimated population emission factors as well as study-estimated default component counts per major equipment to those in subpart W. Comparison of the study-estimated default component counts per major equipment found that the subpart W values underestimate the count of components found on major equipment in the field (Zimmerle *et al.,* 2020; Pacsi *et al.,* 2019). Regarding a comparison of the population emission factors and component counts per major equipment between the subpart W eastern and western values, Zimmerle *et al.* (2020) was the only field study to include both eastern and western facilities, and the study values showed ''no statistically significant differences between eastern and western U.S. regions.'' Rutherford *et al.* (2021) also found their study-estimated population emission factors to be higher than those in subpart W, noting that one of the contributing factors to this difference was the use of the eastern factors in subpart W, which appear to significantly undercount emissions. Rutherford *et al.* (2021) noted that the impact of the use of the eastern factors has grown over time as the production in the eastern region of the U.S. has increased from less than 5 percent of gas produced to nearly 30 percent of the gas produced.

Based on our review of these studies, we are proposing to amend the population count method for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities using these more recent study data, consistent with section II.A.1 of this preamble. These proposed amendments include new population emission factors that are on a per major equipment basis rather than a per component basis. As mentioned previously, the vast majority of reporters estimate the component counts using Component Count Method 1. By providing emission factors on a major equipment basis instead of by component, we would eliminate the step to estimate the number of components. All facilities would be able to inventory their major equipment and consistently apply the same emissions factor to estimate emissions. This would reduce reporter burden and reduce the number of errors in the calculation of emissions, as we find that numerous facilities incorrectly estimate the number of components using Component Count Method 1 while providing consistently estimated emission results. The major equipment emission factors were developed by combining data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) to provide population emission factors by major equipment and site type (*i.e.,* gas or oil). The emission factors were derived by summing the leaker emissions by major equipment type, including wellhead, separator, meters/piping, compressor, acid gas removal unit, dehydrator, header, heater treater, and storage vessel, by the reported site type and dividing those leaker emissions by the count of major equipment screened to yield an emission factor in units of scf whole gas/hour-equipment. Specific to meters/piping and consistent with current requirements related to meters/piping at 40 CFR 98.233(r)(2)(i)(A), we are proposing in 40 CFR 98.233(r)(2) to specify that one meters/piping equipment should be included per well-pad for onshore petroleum and natural gas production operations and the count of meters in the facility should be used for this equipment category at onshore petroleum and natural gas gathering and boosting facilities. As a consequence of the broader scope of equipment surveyed in the Pacsi/Zimmerle studies, the proposed emission factors include more pieces of major equipment than are currently included in subpart W. The derivation of the proposed emission factors is discussed in more detail in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. The proposed major equipment emission factors would replace the component-based emission factors in the current Table W–1A. We are also proposing to revise the titles of Tables W–1B, W–1C, and W–1D to clarify that they apply to reporting years up to and including RY2022. These tables would not apply to subsequent reporting years as they provide activity data that would no longer be needed for the population count method for these industry segments. We are seeking comment on the approach of providing population count emission factors by major equipment.

We note that the application of these emission factors is by site type such that for onshore petroleum and natural gas production facilities, gas well sites should use the proposed gas service emission factors and oil well sites should use the proposed oil service emission factors. Similarly, for onshore petroleum and natural gas gathering and boosting facilities, we consider all equipment to be in gas service consistent with the language in 40 CFR 98.233(r)(2); thus, the proposed gas service factors from Table W–1A should be applied to all equipment counts. We

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[85] Pacsi, A. P. et al. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elementa (2019). *https://doi.org/10.1525/elementa.368.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[86] Zimmerle, D., et al. *Methane Emissions from Gathering Compressor Stations in the U.S.* Environmental Science & Technology *54* (12), 7552–7561 (2020). *https://doi.org/10.1021/acs.est.0c00516.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[87] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. *Closing the methane gap in US oil and natural gas production inventories.* Nat Commun 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

are proposing language clarifying the service-specific application of these emission factors specifically for onshore petroleum and natural gas production in 40 CFR 98.233(r)(2).

Natural Gas Distribution Emission Factors. Natural Gas Distribution companies quantify the emissions from equipment leaks from pipeline mains and services, below grade transmission distribution transfer stations, and below grade metering-regulating stations following the procedures in 40 CFR 98.233(r). This method uses the count of equipment, subpart W population emission factors in Table W–7 (proposed to be moved to Table W–8), and operating time to estimate emissions. The population emission factors for pipeline mains and services in Table W–7 (proposed to be moved to Table W–8) are based on information from the 1996 GRI/EPA study.[88] Specifically for plastic mains, additional data are sourced from a 2005 ICF analysis.[89] The population emission factors for pipeline mains are published per mile of main by pipeline material and emission factors for pipeline services are published per service by pipeline material. The population emission factors for below grade stations in Table W–7 (proposed to be moved to Table W–8) are based on information from the 1996 GRI/EPA study.[90] The population emission factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations are published per station by three inlet pressure categories (>300 psig, 100–300 psig, <100 psig).

The EPA is proposing to update the population emission factors in Table W–7 (proposed to be moved to Table W–8) to subpart W using the results of studies and information that were not available when the rule was finalized in 2010. Notably, the EPA reviewed recent studies and updated the emission factors for several natural gas distribution sources, including pipeline mains and services and below grade stations, for the 2016 U.S. GHG Inventory.[91] [92] The majority of the U.S. GHG Inventory updates were based on data published by Lamb *et al.* in 2015.[93] Since the time that the 2016 U.S. GHG Inventory updates were made, additional studies for pipeline distribution mains have been published and reviewed by the EPA, notably Weller *et al.* in 2020.[94] Our assessment of the studies published since subpart W was finalized supports revising the emission factors for pipelines in the Natural Gas Distribution industry segment of subpart W. For more information on the review and analysis of the various studies, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

The population emission factors for distribution mains and services are a function of the average measured leak rate (scf/hr) and the frequency of annual leaks observed (leaks/mile-year or leaks/service-year) by pipeline material (*e.g.,* protected steel, plastic). The Lamb *et al.* and Weller *et al.* studies utilized different approaches for quantifying leak rates and determining the pipeline material-specific frequency of annual leaks. The Lamb *et al.* study quantified leaks from distribution mains and services using a high volume sampling method and some downwind tracer measurements and estimated the frequency of leaks by pipeline material using company records and Department of Transportation (DOT) repaired leak records from six local distribution companies (LDCs). This methodology was consistent with the GRI/EPA study. The Weller *et al.* study quantified leaks from only distribution mains using the Advanced Mobile Leak Detection (AMLD) technique, which involves mobile surveying using high sensitivity instruments and algorithms that predict the leak location and size, attributed leaks to the pipeline material using geographic information system (GIS) data, and estimated the frequency of leaks using modeling.

During our assessment of the Lamb *et al.* and Weller *et al.* studies, we identified the method for leak quantification as being a key strength of the Lamb *et al.* study and the significantly larger sample size used in estimating the annual leak frequency as being a key strength of the Weller *et al.* study. In order to take advantage of the strengths of both studies, we are proposing to amend the subpart W emission factors for distribution mains using the measurements from Lamb *et al.* combined with the pipeline material specific leaks per mile data from Weller *et al.* We are proposing to amend the subpart W emission factors for distribution services using the measurements from Lamb *et al.* only, consistent with the emission factors used in the 2016 U.S. GHG Inventory, because services were not included in the Weller *et al.* study. See the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424) for more information on our assessment of both studies and the derivation of the proposed emission factors from the data published by Lamb *et al.* and Weller *et al.* We are seeking comments on the approach of combining data from both studies to update the distribution mains emission factors. As alternatives to the proposed amendments, we also considered updating the distribution mains emission factors using data from each study independently. Accordingly, we are also seeking comment on whether using data only from Lamb *et al.,* consistent with the emission factors used in the U.S. GHG Inventory, or only from Weller *et al.* to update the distribution mains emission factors would be preferable over the combined approach included in this proposal, and if so, which study is preferred and why.

For below grade stations, the 2016 U.S. GHG Inventory also began applying a new emission factor from the data published by Lamb *et al.* to the count of stations to estimate emissions from these sources. In order to assess the

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[88] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell, M.V. Campbell, and D.L. Epperson, Radian International LLC. GRI–94/0257.2b, EPA–600/R–96–080i. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[89] ICF. *Fugitive Emissions from Plastic Pipe,* Memorandum from H. Mallya and Z. Schaffer, ICF Consulting to L. Hanle and E. Scheehle, EPA. June 30, 2005. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[90] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell and B.E. Stapper, Radian International LLC. GRI–94/0257.27, EPA–600/R–96–080j. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[91] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Natural Gas Distribution Emissions.* December 2015. Available at *https://www.epa.gov/sites/production/files/2016-02/documents/proposed_revisions_to_ng_distribution_segment_emissions.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[92] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2014: Revisions to Natural Gas Distribution Emissions.* April 2016. Available at *https://www.epa.gov/sites/production/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[93] Lamb, B.K. *et al.* ''Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.'' *Environ. Sci. Technol.* 2015, 49, 5161–5169. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[94] Weller, Z.D.; Hamburg, S.P.; and Von Fischer, J.C. 2020. ''A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems.'' *Environ. Sci. Technol.* 2020, *54*(1), 8958. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

appropriateness of incorporating this revision into the subpart W requirements for below grade stations (*i.e.,* replacing the set of below grade emission factors by station type and inlet pressure with one single emission factor), the EPA performed an analysis of the reported subpart W data for below grade stations compared to data from the recent studies (see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424). We found that the subpart W reported station count combined with the current subpart W emission factors yields an average emission factor similar to the U.S. GHG Inventory emission factor; as such, using either set of emission factors would yield approximately the same emissions results for the GHGRP.

Therefore, we are proposing to amend the emission factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations in Table W–7 (proposed to be moved to Table W–8) to a single emission factor without regard to inlet pressure. We are also proposing to amend the corresponding section header in Table W–7 (proposed to be moved to Table W–8) for below grade station emission factors and the references to Table W–7 (proposed to be moved to Table W–8) in 40 CFR 98.233(r)(6)(i) to clarify the emission factor that should be applied to both types of below grade stations (*i.e.,* transmission-distribution transfer and metering-regulating). This proposed amendment would impact the reporting requirements as well, as it would consolidate six emission source types to two emission source types (below grade transmission-distribution transfer stations and below grade metering-regulating stations, without differentiating between inlet pressures) for purposes of reporting under 40 CFR 98.236(r)(1). This proposed amendment would improve the data quality through use of more recent emission factors and would be consistent with changes made to the U.S. GHG Inventory. It would also result in reporting of fewer data elements, consistent with section II.B.3 of this preamble.

Gathering pipeline emission factors. Facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment quantify the emissions from equipment leaks from gathering pipelines following the procedures in 40 CFR 98.233(r). This method uses the count of equipment, subpart W population emission factors in Table W–1A, and operating time to estimate emissions. The population emission factors for gathering pipeline mains in Table W–1A are based on leak rates from natural gas distribution companies and gathering pipeline-specific activity data as provided in the 1996 GRI/EPA study.[95] The population emission factors for gathering pipelines are published per mile by pipeline material.

As noted previously in this section, the EPA is proposing to update the natural gas distribution population emission factors in Table W–7 (proposed to be moved to Table W–8) to subpart W using the results of studies and information that were not available when the rule was originally finalized. In particular, the EPA is proposing to update the leak rate portion of the emission factor based on data published by Lamb *et al.* in 2015.[96] The EPA has reviewed the recent studies published for onshore petroleum and natural gas gathering and boosting facilities as well as the additional studies for pipeline distribution mains, and none of the studies provide new emissions data or activity data specific to gathering pipelines. Therefore, consistent with the updates to the emission factors for distribution mains, and consistent with section II.A.1 of this preamble, we are proposing to revise the gathering pipeline population emission factors to use the leak rates from Lamb *et al.* (2015). We are not proposing to update the activity data (leaks per mile of pipeline) portion of the emission factors, as the information in the 1996 GRI/EPA study continues to be the best available data specific to gathering pipelines. For more information on the proposed updates to the gathering pipeline population emission factors, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

m. Other Large Release Events

We are proposing to add an additional emissions source, referred to as ‘‘other large release events’’ to capture abnormal emission events that are not fully accounted for using existing methods in subpart W, consistent with section II.A.3 of this preamble. Most of the emission sources and methodologies included in subpart W characterize emissions that routinely occur at oil and gas facilities as part of their normal operations. While some sources covered by subpart W methodologies, such as equipment leaks, may represent ‘‘malfunctioning’’ equipment, these sources are ubiquitous across the oil and gas sector, are generally small, and have been studied and characterized. On the other hand, there have been several large, atypical release events at oil and gas facilities over the last few years where it was difficult to sufficiently include these emissions in annual GHGRP reports. For example, a storage wellhead leak at Aliso Canyon released approximately 100,000 metric tons of CH_4 between October 2015 and February 2016 and a well blowout in Ohio released an estimated 40,000 to 60,000 tons of CH_4 in a 20-day period in 2018. The emissions from these types of releases were not well represented using the existing calculation methodologies in subpart W because these were not common or predictable events.[97] Because these events can significantly contribute to the total GHG emissions from this sector, we are proposing new calculation methods for estimating the GHG emissions from other large release events in 40 CFR 98.233(y) and requirements for reporting other large release events in 40 CFR 98.236(y). These proposed additional calculation and reporting requirements would apply to all subpart W industry segments and would improve the accuracy of emissions reported under subpart W and enhance the overall quality of the data collected under the GHGRP.

The new calculation requirements being proposed rely on measurement data or engineering estimates of the amount of gas released and measurement data, if available, or process knowledge (best available data) to estimate the composition of the released gas. The proposed requirement to calculate and report GHG emissions from other large release events would be limited to events that release at least 250 $mtCO_2e$ per event. This is equivalent to approximately 500,000 scf of pipeline quality natural gas. We selected this proposed threshold to capture reporting for large emission events, such as well blowouts, well releases, and large pressure relief venting. In order to establish this reporting threshold, we first assessed other emission sources that we considered large. Specifically,

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[95] GRI/EPA. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Prepared for Gas Research Institute and U.S. Environmental Protection Agency National Risk Management Research Laboratory by L.M. Campbell, M.V. Campbell, and D.L. Epperson, Radian International LLC. GRI–94/0257.2b, EPA–600/R–96–080i. June 1996. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[96] Lamb, B.K. *et al.* ‘‘Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.’’ *Environ. Sci. Technol.* 2015, 49, 5161–5169. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[97] The EPA notes that the full emissions from this event were included in the U.S. GHG Inventory based on the results of multiple measurement studies.

we considered completions of hydraulically fractured wells that are not controlled (*i.e.,* not performed using reduced emission completions) to be large emissions events. Based on analysis of GHGRP data of wells that are not reduced emission completions and that vent, the U.S. GHG Inventory developed an average emission factor of about 360 $mtCO_2e$ for these events. Because this is an average emissions factor, some uncontrolled hydraulically fractured completions will be below this average and some above. From this assessment, we considered 250 $mtCO_2e$ to be a reasonable emissions threshold for a ''large'' event.

While 250 $mtCO_2e$ is much lower than the emissions from the Aliso Canyon or Ohio well blowout releases, we determined that a 250 $mtCO_2e$ threshold would be needed to capture most well blowouts. There are limited data to quantify an ''average'' well blowout, but the 2021 U.S. GHG Inventory uses an oil well blowout emission factor of 2.5 MMscf per event. As this is an average, many well blowouts will be less than this average value. The 250 $mtCO_2e$ threshold is approximately equivalent to 500,000 scf of natural gas, which compares reasonably well with the lower range of well blowouts expected based on the average emission factor of 2.5 MMscf per event.

We also find that the 250 $mtCO_2e$ threshold (approximately equivalent to 500,000 scf natural gas release) is a reasonable threshold for requiring individual assessments of releases. In subpart Y (Petroleum Refineries), we established event-specific emission calculation requirements for startup, shutdown, or malfunction releases to a flare exceeding 500,000 scf per day (40 CFR 98.253(b)(1)(iii)). While the subpart Y threshold is per day rather than per event, it is also specific to flared emissions. For flared emissions to exceed a 250 $mtCO_2e$ threshold, approximately 4 MMscf of natural gas would have to be released to the flare, which is well above the subpart Y ''per day'' threshold for flares. Thus, we conclude that the 250 $mtCO_2e$ per event threshold is an appropriate size threshold for requiring event-specific emission calculations to be performed. More information regarding our review and characterization of types of other large release events is included in the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. Emissions from smaller or routine release events would still be reported, as applicable, under the source-specific calculation and reporting requirements in subpart W.

We are proposing a definition of ''other large release events'' in 40 CFR 98.238 to clarify the types of releases that must be characterized for this new emissions source and specify that other large release events include, but are not limited to, well blowouts, well releases, releases from equipment rupture, fire, or explosions. Currently, there are no calculation methodologies or reporting requirements for these types of large releases in subpart W. The proposed definition would also include large pressure relief valve releases from process equipment other than onshore production and onshore petroleum and natural gas gathering and boosting storage tanks that are not included in the blowdown definition. While subpart W currently includes emission factors for pressure relief devices, these equipment leak emission factors only account for leaks past a pressure relief valve that is in the closed position, not releases from the complete opening of these valves. The proposed definition specifies that pressure relief valve releases from onshore production and onshore petroleum and natural gas gathering and boosting storage tanks would not be considered other large release events because the calculation methodology for these storage tanks currently assumes all flash gas will be emitted. As noted in section III.K.1.g of this preamble, pressure relief emission releases from onshore production and onshore petroleum and natural gas gathering and boosting storage tanks generally occur from the thief hatch and these releases must be accounted for when calculating the fraction of flash gas that is recovered or sent to a flare, if applicable. A more detailed discussion of certain other emissions events we have identified and expect to be subject to the ''other large release events'' proposed amendments is included in the subpart W TSD available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

As part of the proposed definition of ''other large release events'' in 40 CFR 98.238, we are also proposing that other large release events include releases from equipment for which the existing calculation methodologies in subpart W would significantly underestimate the episodic nature of these emissions. For example, subpart W contains population emission factors and leaker emission factors for estimating equipment leak emissions for storage wellheads. Thus, it is possible to argue that subpart W includes calculation methodologies for the equipment responsible for the Aliso Canyon release. However, the calculation methodologies in subpart W do not accurately estimate emissions from such an uncharacteristically large event because such events are so rare that they generally do not exist when measurement studies are conducted. Additionally, skewing the emission factors used to account for such an event would yield erroneously high emissions from normal operations for nearly all reporting facilities. Thus, we determined that it is more accurate for facility-specific reporting to account for these large releases on a per event basis. Therefore, if a single leak or event has emissions that exceed the emissions estimated by an applicable methodology included in subpart W by 250 $mtCO_2e$ or more, we are proposing that such releases would be included in the definition of ''other large release events'' and that reporters would be required to calculate and report the GHG emissions from these events using the proposed requirements for other large release events.

Further, we are proposing to define the terms ''well release'' and ''well blowout'' in 40 CFR 98.238 to assist reporting facilities with differentiating between these types of release events that could potentially occur at wells. We find that a well blowout is generally distinguished by a complete loss of well control for a long duration of time and a well release is characterized as a short period of uncontrolled release (not the controlled pre-separation stage of well flowback in a hydraulically fractured completion) followed by a period of controlled release in which control techniques were successfully implemented.

Finally, we are proposing a reporting requirement that would require subpart W reporters to indicate whether an ''other large release event'' was identified under any provisions of NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62. As described in section III.J.1.k of this preamble, the EPA proposed a fugitive emissions monitoring program in NSPS OOOOb and EG OOOOc, including an alternative screening approach for fugitive emissions from well sites and compressor stations that would allow the use of advanced measurement technologies to detect emissions. As part of that proposal, the EPA also requested comment on how to evaluate and design a requirement for owners and operators to investigate and remediate large emission events, which could include the use of alternative screening techniques and advanced measurement technologies, all of which, if finalized, could potentially be used to identify ''other large release events'' under subpart W. While some methods that could be used to identify and estimate the magnitude of these ''other large release events,'' such as monitors installed on mobile vehicles or aircraft or methane satellite imagery, would not be specifically included as measurement methods in subpart W, these methods may be used to quantify the emissions release for ''other large release events'' under the ''engineering estimates'' and ''best available data'' provisions of the proposed calculation methodology. To improve the EPA's understanding of the technologies and methods used to identify reported ''other large release events,'' including the impact of periodic screenings with advanced measurement technologies on the identification of large release events, we are proposing reporting provisions that would require reporters to indicate whether each ''other large release event'' was identified as part of compliance with NSPS OOOOb or the applicable state plan or applicable Federal plan in 40 CFR part 62.

n. Combustion

Methane slip from compressor engines. All facilities reporting under subpart W except those in the Onshore Natural Gas Transmission Pipeline industry segment must include combustion emissions in their annual report. Facilities in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments calculate emissions in accordance with the provisions in 40 CFR 98.233(z) and report combustion emissions per 40 CFR 98.236(z). Reporters in the other industry segments calculate and report combustion emissions under subpart C (General Stationary Fuel Combustion Sources). The authors of several recent studies have examined combustion emissions at Onshore Petroleum and Natural Gas Gathering and Boosting facilities and have demonstrated that a significant portion of emissions can result from unburned methane entrained in the exhaust of natural gas compressor engines (also referred to as ''combustion slip'' or ''methane slip''). These studies contend that emissions from natural gas compressor engines included in the GHGRP are significantly underestimated because they do not account for combustion slip.[98] The EPA performed a review of each of these studies and the U.S. GHG Inventory to determine whether and how combustion slip emissions have been incorporated into published data and how the incorporation of combustion slip would affect the emissions from the petroleum and natural gas system sector reported to the GHGRP (see the subpart W TSD, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

Based on the EPA's review and analysis, there appears to be combustion slip for all compressor engine types at oil and gas facilities. In addition, while the recent studies are focused on the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, the EPA's literature review found the presence of combustion slip in different industry segments, so it appears that combustion slip is dependent on the type of engine and not the application (*i.e.,* we expect combustion slip from compressor engines regardless of the industry segment). Therefore, the EPA is proposing to revise the methodologies for determining combustion emissions from compressor engines to account for combustion slip, consistent with section II.A.3 of this preamble. For the three subpart W industry segments that calculate combustion emissions per 40 CFR 98.233(z), we are proposing to accomplish this with two amendments to the calculation methods and the addition of one new reporting requirement. For compressor engines in those subpart W industry segments that combust natural gas and qualify to determine emissions using the subpart C calculation methodologies per 40 CFR 98.233(z)(1) and proposed new 98.233(z)(2),[99] we are proposing that reporters would use subpart-W specific emission factors by engine design class (*e.g.,* 2-stroke lean-burn, 4-stroke lean-burn, 4-stroke rich-burn, or other) in proposed new Table W–9 rather than the emission factors in Table C–2. For compressor engines that combust natural gas and determine emissions per 40 CFR 98.233(z)(2) (proposed to be moved to 40 CFR 98.233(z)(3)), we are proposing updated combustion efficiency value(s) (η) by engine design class to be used in equations W–39A and W–39B that would reflect combustion slip. We are also proposing to add a reporting requirement to 40 CFR 98.233(z)(2) to specify the design class of reported internal combustion units that are compressor-drivers to facilitate verification of the selected emission factors and efficiencies, as applicable, and the resulting emissions.

In an analogous amendment for the reporters in the other subpart W industry segments that calculate and report combustion emissions under subpart C, we are proposing that they also use subpart W-specific emission factors rather than the emission factors in Table C–2. Currently, these facilities use either equation C–8, C–8a, C–8b, C–9, C–9a, C–9b, or C–10 in 40 CFR 98.33(c), as it corresponds to the Tier methodology selected to estimate their CO_2 emissions, to estimate CH_4 emissions. These equations rely on the use of a default CH_4 emission factor from Table C–2 to estimate emissions. As described in section III.B of this preamble, the emission factor term definition in each of these equations is proposed to be amended to reference Table W–9 rather than Table C–2 specifically for quantifying emissions from compressor-drivers. We are also proposing to add a footnote to Table C–2 to specify that the default CH_4 emission factor should only be used for combustion devices that are not compressor-drivers.

Clarifications of calculation methodologies. As noted previously in this section, Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution facilities report combustion emissions calculated in accordance with 40 CFR 98.233(z) instead of reporting under subpart C. Stakeholders (*e.g.,* GPA Midstream) have identified several concerns with the requirements in 40 CFR 98.233(z). First, GPA Midstream has indicated that for fuels using the existing provisions of 40 CFR 98.233(z)(2) to calculate emissions, the requirements for determining the gas composition could result in inaccurate calculations of emissions for some facilities.[100] In particular, 40 CFR 98.233(z)(2)(ii) currently specifies that to determine the concentrations of

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[98] Zimmerle *et al., Characterization of Methane Emissions from Gathering Compressor Stations: Final Report* (October 2019 Revision) and Vaughn *et al.,* ''Methane Exhaust Measurements at Gathering Compressor Stations in the United States,'' *Environmental Science & Technology.* 2021, *55* (2), 1190–1196, both available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[99] See section III.J.2.f of this preamble for information on the proposed amendments to 40 CFR 98.233(z) to increase the flexibility for reporters to use the subpart C calculation methodologies.

[100] See Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. See also Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Both letters are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

hydrocarbon constituents in the flow of gas to the unit, reporters must either use a continuous gas composition analyzer (if one is present) or the procedures in the applicable paragraph in 40 CFR 98.233(u)(2) of this section. For onshore petroleum and natural gas gathering and boosting facilities, 40 CFR 98.233(u)(2) specifies use of the annual average gas composition based on the most recent available analysis of the gas received at the facility. However, GPA Midstream explained that onshore petroleum and natural gas gathering and boosting facilities do not necessarily use the gas received at their facility for combustion. For example, if the gas received at the facility is not suitable for combustion, they may mix the gas with purchased natural gas. In that case, the annual average composition of gas received at the facility would not be representative of the gas sent to the combustion unit (as required by 40 CFR 98.233(z)(2)), which could result in inaccurate emissions. Therefore, the EPA is proposing to revise the language in 40 CFR 98.233(z)(2)(ii) (proposed to be moved to 40 CFR 98.233(z)(3)(ii)(B)) to allow the use of engineering estimates based on best available data to determine the concentration of gas hydrocarbon constituent in the flow of gas to the unit. This proposed amendment would allow reporters to use the best information available to determine the gas composition while maintaining the option for reporters to use 40 CFR 98.233(u)(2) if they do not have other stream-specific information. In addition to improving the accuracy of the emissions calculated and therefore the quality of data collected, consistent with section II.A.2 of this preamble, this proposed amendment is expected to provide additional flexibility for reporters, consistent with section II.B.2 of this preamble.

Second, GPA Midstream indicated that the existing provisions of 40 CFR 98.233(z)(1)(ii) are unclear and that some member companies have been interpreting those provisions to mean that reporters with combustion sources at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities must use the calculation methodologies in subpart W rather than subpart C (even given the provisions in 40 CFR 98.233(z)(1) that reference subpart C for certain fuels).[101] The existing provisions of 40 CFR 98.233(z)(1)(ii) are intended to refer only to the reporting requirements and are not intended to define which calculation methodologies can be used. In the current rule, the provisions in the 40 CFR 98.233(z)(1) introductory text define which calculation methodologies can be used, and 40 CFR 98.233(z)(1)(ii) simply indicates that all reporters with combustion sources at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities must report those emissions in the e-GGRT system under subpart W rather under subpart C. As part of the amendments described in this section, consistent with section II.A.5 of this preamble, 40 CFR 98.233(z)(1)(ii) is proposed to be moved to 40 CFR 98.233(z)(4), and we are proposing wording changes to be clear that this paragraph refers only to reporting. We are also proposing to add a reference to this new paragraph 40 CFR 98.233(z)(4) in both 40 CFR 98.233(z)(1)(ii) and 98.233(z)(2)(ii) (as proposed to be amended).

o. Leak Detection and Measurement Methods

Acoustic leak detection. For emission source types for which measurements are required, subpart W specifies the methods that may be used to make those measurements in 40 CFR 98.234(a). To improve the quality of the data when an acoustic leak detection device is used, consistent with section II.A.2 of this preamble, we are proposing two revisions to the acoustic measurement requirements in 40 CFR 98.234(a)(5). First, for stethoscope type acoustic leak detection devices (*i.e.,* those designed to detect through-valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate), we are proposing that a leak is detected if an audible leak signal is observed or registered by the device. Second, we are proposing that if a leak is detected using a stethoscope type device, then that leak must be measured using one of the quantification methods specified in 40 CFR 98.234(b) through (d) and that leak measurement must be reported regardless of the volumetric flow rate measured. These proposed revisions would improve the accuracy of emissions reported for compressors and transmission tanks when an acoustic leak detection device is used.

High volume samplers. We are proposing two revisions to the high volume sampler methods to improve the quality of the data when high volume samplers are used for flow measurements, consistent with section II.A.2 of this preamble. First, we are proposing to add detail to 40 CFR 98.234(d)(3) to clarify the calculation methods associated with high volume sampler measurements. Generally, high volume samplers measure methane flow, not whole gas flow. However, the current calculation methods in 40 CFR 98.234(d)(3) treat the measurement as a whole gas measurement. Therefore, we are clarifying the calculation methods needed if the high volume sampler outputs methane flow in either a mass flow or volumetric flow basis. Specifically, we are proposing methods to determine natural gas (whole gas) flows based on measured methane flows.

Second, we are proposing to add a paragraph at 40 CFR 98.234(d)(5) to clarify how to assess the capacity limits of a high volume sampler. Currently, 40 CFR 98.234(d) simply states to ''Use a high volume sampler to measure emissions within the capacity of the instrument''; there is no other information provided to clarify what ''within the capacity of the instrument'' means or how it is determined. We understand that there are different manufacturers, but most common high volume samplers report maximum sampling rates of 10 to 11 cubic feet per minute (cfm) and maximum methane flow quantitation limits of 6 to 8 cfm. Based on our review of reported high volume sampler measurements, we found that 2 to 5 percent of high volume sampler measurements for all types of compressor sources (for both centrifugal and reciprocating compressors) are likely at or beyond the expected capacity limits of the high volume sampler instrument. Considering actual sampling rates, gas collection efficiencies near the sampling rates, and reported methane quantitation limits relative to maximum sampling rates, we determined that whole gas flow rates exceeding 70 percent of the device's maximum rated sampling rate is an indication that the device will not accurately quantify the volumetric emissions, which we deem to exceed the capacity of the device. Therefore, we are proposing to specify that methane flows above the manufacturer's methane flow quantitation limit or total volumetric flows exceeding 70 percent of the manufacturer's maximum sampling rate indicate that the flow is beyond the capacity of the instrument and that flow meters or calibrated bags must be used to quantify the flow rate. For more information on our review, see the subpart W TSD, available in the

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[101] Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

p. Onshore Petroleum and Natural Gas Gathering and Boosting Compressor Stations

The EPA received feedback from GPA Midstream that a count of compressor stations per Onshore Petroleum and Natural Gas Gathering and Boosting facility would provide the EPA with improved data on the number and type of equipment at gathering and boosting stations, which could help to better inform future rulemakings.[102] In addition, the EPA could use information on the count of compressor stations to improve the process of verifying annual reports to the GHGRP. As an example, a facility with high emissions for a particular source type compared to other facilities in the same basin might currently be identified as a potential outlier. However, if the report also indicated that the facility has a large number of compressor stations compared to other facilities, the EPA could use that information during report verification to confirm the high emissions without needing to contact the facility owner or operator. Therefore, the EPA is proposing to add a requirement in 40 CFR 98.236(aa)(10)(v) to report the count of compressor stations for facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, consistent with section II.A.4 of this preamble. Additionally, the count of compressor stations per facility would allow for refinements to the activity data used by the U.S. GHG Inventory. In particular, the calculated national-level compressor station activity data used by the U.S. GHG Inventory could be informed by reported compressor station counts for Onshore Petroleum and Natural Gas Gathering and Boosting facilities subject to subpart W, which improves the U.S. GHG Inventory estimate of total national emissions. The EPA is also proposing a definition of ‘‘compressor station’’ in 40 CFR 98.238 to be used for the purposes of this reporting requirement to reduce any potential reporter confusion.

Based on the definition of Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, this industry segment also includes ‘‘centralized oil production sites.’’ These are sites that collect oil from multiple well pads but that do not have compressors (*i.e.,* are not ‘‘compressor stations’’). Therefore, we are proposing to add a requirement in 40 CFR 98.236(aa)(10)(vi) to report the count of centralized oil production sites for facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, consistent with section II.A.4 of this preamble. We are also proposing to add a definition of ‘‘centralized oil production site’’ in 40 CFR 98.238 to be used for the purposes of this reporting requirement. These proposed additional data elements would enhance the overall quality of the data collected under the GHGRP.

q. Onshore Natural Gas Transmission Pipeline Throughput Information

Similar to Natural Gas Distribution facilities, Onshore Natural Gas Transmission Pipeline facilities are currently required to report five throughput volumes under subpart W, as specified in 40 CFR 98.236(aa)(11). These five data reporting elements include: the quantity of natural gas received at all custody transfer stations; the quantity of natural gas withdrawn from in-system storage; the quantity of gas added to in-system storage; the quantity of gas transferred to third parties; and the quantity of gas consumed by the transmission pipeline facility for operational purposes. As noted in section III.J.2.g of this preamble, the EPA has received stakeholder comments on the reporting elements for Natural Gas Distribution facilities, including questions submitted to the GHGRP Help Desk, regarding the term ‘‘in-system storage.’’ Although the questions were specific to Natural Gas Distribution facilities, the term ‘‘in-system storage’’ is also included in the throughput reporting elements for Onshore Natural Gas Transmission Pipeline facilities at 40 CFR 98.236(aa)(11)(ii) and (iii). After consideration of the stakeholder comments, the EPA is proposing to clarify the term ‘‘in-system.’’ Specifically, we are proposing to amend 40 CFR 98.236(aa)(11)(ii) and (iii) to clarify that ‘‘in-system’’ withdrawals/additions of natural gas from storage are specifically referring to Underground Natural Gas Storage and LNG Storage facilities that are owned and operated by the onshore natural gas transmission pipeline owner or operator that do not report under subpart W as direct emitters themselves. These amendments are expected to improve data quality consistent with section II.A.5 of this preamble.

2. Proposed Revisions to Streamline and Improve Implementation for Subpart W

As further described in section II.B of this preamble, we are also proposing amendments to remove, reduce, or simplify requirements that would streamline and improve implementation while maintaining the quality of the data collected under part 98. To determine which reporting requirements and data elements of subpart W to propose amending, the EPA reviewed correspondence with reporters during the annual verification of GHGRP data, questions submitted to the GHGRP Help Desk and the responses provided, and the specific regulatory language of subpart W. As a result of that process, the EPA is proposing to eliminate, clarify, or otherwise amend select calculation methodologies and reporting requirements as described in this section. Consistent with section II.B.2 of this preamble, some of the proposed amendments would add monitoring or reporting flexibility for certain calculation methodologies. Other proposed revisions would remove reporting requirements that are redundant with data already reported to the EPA or no longer being used at this time, as further described in section II.B.3 of this preamble.

a. Dehydrator Vents

Removal of requirements for desiccant dehydrators. Subpart W currently requires reporting of desiccant dehydrators as a subcategory of dehydrator vents. Based on the data reported to date, the emissions from these sources are less than 0.1 percent of total reported emissions from dehydrator vents (in RY2020, desiccant dehydrators contributed 760 $mtCO_2e$ of the total 3.35 million $mtCO_2e$ from all dehydrator vent emissions). In addition, it appears that a significant percentage of the emissions reported to date may be from molecular sieve dehydrators; however, we never intended to require reporting of emissions from such units, and based on the definition of ‘‘dehydrator’’ in 40 CFR 98.6, we do not read the rule to require such reporting. In RY2015 through RY2020, about 60 percent of the facilities that reported counts of desiccant dehydrators also reported emissions of 0 $mtCO_2e$ (516 out of 897 reporters), and more than one-quarter of the reported desiccant dehydrators were at facilities that reported 0 emissions from desiccant dehydrators (1,888 out of 7,139 units). Furthermore, facilities that report emissions from desiccant dehydrators in a given year may not have depressurized every one of their desiccant dehydrators

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[102] Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

in that year, but this cannot be determined from the reported data because emissions are reported at the facility level instead of per dehydrator. This pattern of emissions reporting is consistent with the expected results for molecular sieve dehydrators because such units typically are opened (depressurized) only once every few years. Thus, a significant percentage of the reported emissions from desiccant dehydrators may be from units that are not subject to reporting, meaning that the actual emissions from desiccant dehydrators would be less than the reported 0.1 percent of the total dehydrator emissions. Therefore, we are proposing to remove requirements for desiccant dehydrators from 40 CFR 98.233(e)(3) and (4) and 40 CFR 98.236(e)(3) of subpart W, consistent with section II.B.2 and II.B.3 of this preamble.[103] As a corollary to the proposed removal of the desiccant dehydrator requirements, we are also proposing to remove the definition of ''desiccant'' and to revise the definition of ''dehydrator'' in 40 CFR 98.6, as discussed in section III.A of this preamble.

As an alternative to removing the requirements for all desiccant dehydrators, we considered revising 40 CFR 98.233(e)(3) to clarify that only devices with desiccant that absorb water (as opposed to those containing materials that adsorb water) are subject to the GHGRP. That change would be consistent with the original intent, as evidenced by the definitions of ''desiccant'' and ''dehydrator'' in 40 CFR 98.6, and it would clarify that molecular sieve units (which contain material that adsorbs water) are not subject to subpart W. That change also would reduce the number of reporters. However, we are not proposing that option because the reported emissions would be extremely small relative to other dehydrator emissions. We request comment on other advantages and disadvantages of this option relative to the proposed plan of deleting requirements for desiccant dehydrators and whether commenters think there are potential benefits of this option that outweigh potential drawbacks.

Although this proposal would remove the desiccant dehydrator requirements from subpart W, other requirements in subpart W may then apply instead. Currently, 40 CFR 98.233(e)(3) and 40 CFR 98.233(i) specify that desiccant dehydrator emissions calculated using equation W–6 do not have to be calculated separately under the blowdown vent stacks provisions in 40 CFR 98.233(i). However, because we are proposing to remove the desiccant dehydrator provisions, the EPA is also proposing to remove the exception at the end of the 40 CFR 98.233(i) introductory paragraph. Thus, the blowdown provisions in 40 CFR 98.233(i) would apply, provided that the volume of space in a desiccant dehydrator that is depressurized to atmosphere is greater than 50 cubic feet. Similarly, in the absence of desiccant dehydrator provisions, if the emissions from depressurizing desiccant dehydrators are routed to a flare, then the emissions would be subject to the requirements for flare stack emissions in 40 CFR 98.233(n). We note that while these emissions may still be reported to the EPA if the proposal to remove the desiccant dehydrator provisions is finalized, they would no longer be required to be calculated and reported separately, which would still streamline implementation for reporters.

Clarification of Count for Glycol Dehydrators with Annual Average Daily Natural Gas Throughput Less Than 0.4 MMscf per Day. As noted in section III.J.1.d of this preamble, for glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscf per day, reporters currently use population emission factors and equation W–5 to calculate volumetric CO_2 and CH_4 emissions per 40 CFR 98.233(e)(2) and report emissions per 40 CFR 98.236(e)(2). Under these current requirements, the count of glycol dehydrators with annual average daily natural gas throughput less than 0.4 MMscf per day could include dehydrators with annual average daily natural gas throughput of 0 MMscf per day (*i.e.,* glycol dehydrators that were not operated during the reporting year). As a result, some annual reports include a nonzero count of dehydrators per 40 CFR 98.236(e)(2)(i) without any corresponding CO_2 and CH_4 emissions. In these cases, it is not clear if the reporter did not report emissions because emissions are not expected, the emissions data were inadvertently omitted, or the nonzero count represents the total count of all dehydrators with annual average daily natural gas throughput less than 0.4 MMscf per day, including those that were not in use.

Therefore, the EPA is proposing to clarify in 40 CFR 98.233(e)(2) that the dehydrators for which emissions are calculated should be those with annual average daily natural gas throughput greater than 0 MMscf per day and less than 0.4 MMscf per day (*i.e.,* the count should not include dehydrators that did not operate during the year). Similarly, the EPA is proposing to clarify that the count of dehydrators in 40 CFR 98.236(e)(2)(i) should also be those with annual average daily natural gas throughput greater than 0 MMscf per day and less than 0.4 MMscf per day. These amendments are expected to streamline and improve implementation, consistent with section II.B.3 of this preamble.

b. Blowdown Vent Stacks

Blowdown equipment types. Subpart W currently requires reporting of blowdowns either using flow meter measurements (40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (40 CFR 98.233(i)(2)). When the Onshore Natural Gas Transmission Pipeline industry segment was added to subpart W in 2015, public commenters indicated that the existing equipment or event types were not appropriate for the new segment, so the EPA developed new equipment or event types that apply only for the Onshore Natural Gas Transmission Pipeline industry segment (80 FR 64275, October 22, 2015). The new equipment or event types were added to the introductory paragraph of 40 CFR 98.233(i)(2), where the existing equipment or event types were already located, resulting in a complex introductory paragraph. Also, both the third sentence and last sentence in 40 CFR 98.233(i)(2) currently read as follows: ''If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event.'' According to this provision, when a blowdown event consists of emissions from two or more equipment types, the emissions must be apportioned to each applicable equipment type, unless such apportionment is not possible.

The EPA is proposing to move the listings of event types and the apportioning provisions to a new 40 CFR 98.233(i)(2)(iv) so that the introductory paragraph in 40 CFR 98.233(i)(2) would be more concise and provide clearer information regarding which requirements are applicable for each blowdown. Proposed 40 CFR 98.233(i)(2)(iv) includes separate paragraphs for each set of equipment and event type categories and would also provide clearer information

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[103] We are also proposing to move the specifications for calculating mass emissions from volumetric emissions for glycol dehydrators with an annual average of daily natural gas throughput that is less than 0.4 MMscf per day from 40 CFR 98.233(e)(4) to 40 CFR 98.233(e)(2), which would consolidate the requirements for those dehydrators.

regarding the applicable requirements for each industry segment.

Blowdown Temperature and Pressure. In the 2015 amendments to subpart W (80 FR 64262, October 22, 2015), the EPA added the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment and the Onshore Natural Gas Transmission Pipeline industry segment and specified that both industry segments are required to report emissions from blowdown vents. Stakeholders representing the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment provided comments on the proposed rule stating that the proposed definition of facility would make equipment geographically dispersed, and blowdowns may occur without personnel on-site or nearby, which would make it difficult to collect the information needed to calculate emissions from each blowdown (80 FR 64271, October 22, 2015). As a result of those comments, the EPA also specified in the final amendments to equation W–14A that for emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the actual temperature and actual pressure.

Since that time, the EPA has received questions through the GHGRP Help Desk indicating that facilities in the Onshore Natural Gas Transmission Pipeline industry segment also have unmanned blowdown vents. Given that a ''facility with respect to the onshore natural gas transmission pipeline segment'' is the total mileage of natural gas transmission pipelines owned and operated by an onshore natural gas transmission pipeline owner or operator, all of the blowdown vents at that facility would be outside the fenceline of a transmission compression station and would be geographically dispersed. The EPA considers it reasonable to assume that those blowdown vents may also be unmanned. Therefore, we are proposing to extend the provisions in equation W–14A of 40 CFR 98.233(i)(2)(i) that allow use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown to the Onshore Natural Gas Transmission Pipeline segment, which would align the requirements for the two geographically dispersed industry segments (Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting) and increase flexibility for Onshore Natural Gas Transmission Pipeline reporters, consistent with section II.B.2 of this preamble.

In addition, similar provisions to allow use of engineering estimates based on best available information to determine the temperature and pressure of an emergency blowdown were not added to equation W–14B of 40 CFR 98.233(i)(2)(i) in 2015 (80 FR 64262, October 22, 2015). We have reviewed this equation and have determined that this omission was inadvertent. Therefore, we are proposing to add provisions to equation W–14B to allow use of engineering estimates to determine the temperature and pressure of an emergency blowdown for both the Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, consistent with equation W–14A.

c. Atmospheric Storage Tanks

Calculation methods 1 and 2 reporting. For facilities reporting atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2, 40 CFR 98.236(j)(1) requires reporting of counts of the total number of atmospheric storage tanks within the sub-basin or county, the number of atmospheric storage tanks that are controlled by a vapor recovery system, the number of atmospheric storage tanks that are controlled by a flare, and the number of atmospheric storage tanks that are not controlled by either a vapor recovery system or a flare. As atmospheric storage tanks are typically controlled by both a vapor recovery system and a flare, these counts allow for overlap and cause confusion among reporters. Additionally, atmospheric storage tanks may be included in multiple categories of counts if the facility elects to add an emissions control partway through the reporting year.

Therefore, the EPA is proposing to reorganize the reporting requirements in 40 CFR 98.236(j)(1) to reduce overlap between several of the current data elements that are reported by control methodology. Specifically, the EPA is proposing to collect only the total number of tanks within the sub-basin or county, the count of atmospheric tanks that routed emissions to vapor recovery and/or flares at any point during the reporting year, and the count of atmospheric tanks that vented gas directly to the atmosphere and did not control emissions using a vapor recovery system or flares at any point during the reporting year.

For consistency with the revisions to the atmospheric storage tank count data elements, the EPA is proposing to require separate reporting of emissions for tanks that did not control emissions using a vapor recovery system or flares at any point during the reporting year and for tanks that routed emissions to vapor recovery and/or flares at any point during the reporting year. For tanks that do not control emissions using a vapor recovery system or flares at any point during the reporting year, facilities would report CO_2 and CH_4 emissions resulting from venting gas directly to the atmosphere. For tanks that rout emissions to vapor recovery and/or flares at any point during the reporting year, facilities would report CO_2, CH_4, and N_2O emissions from flares and the total mass of CO_2 and CH_4 that was recovered using a vapor recovery system in addition to the CO_2 and CH_4 emissions resulting from venting gas directly to the atmosphere. With this reorganization of the emissions reporting requirements for atmospheric storage tanks, the EPA expects to streamline reporting and reduce redundancy between data elements, consistent with section II.B.3 of this preamble.

Additionally, the EPA is proposing to remove the requirement to report an estimate of the number of atmospheric storage tanks that are not on well-pads and that are receiving the facility's oil (40 CFR 98.236(j)(1)(xi)), consistent with section II.B.3 of this preamble. This reporting requirement is redundant because all Onshore Petroleum and Natural Gas Production facilities reporting atmospheric storage tank emissions calculated using Calculation Method 1 or Calculation Method 2 must also report the total number of atmospheric tanks in the sub-basin per 40 CFR 98.236(j)(1)(x).

Calculation method 3 reporting. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, reporters follow the Calculation Method 3 methodology specified in 40 CFR 98.233(j)(3) and equation W–15. Equation W–15 uses population emission factors and the count of applicable separators, wells, or non-separator equipment to determine the annual total volumetric GHG emissions at standard conditions. The associated reporting requirements in 40 CFR 98.236(j)(2)(i)(E) through (F) require reporters to delineate the count used in equation W–15 into the number of wells with gas-liquid separators in the basin and those without gas-liquid separators. The EPA has received feedback through correspondence with reporters via e-GGRT that these reporting requirements are unclear.

After consideration of this feedback, the EPA has made a preliminary determination that these reporting requirements are not consistent with the language used in the definition of the ‘‘Count’’ variable in equation W–15, nor are they inclusive of all equipment to be included in the count.

Therefore, the EPA is proposing to revise 40 CFR 98.236(j)(2)(i)(E) to completely align the requirement with the total ‘‘Count’’ input variable in equation W–15. The EPA proposes to amend the language in 40 CFR 98.236(j)(2)(i)(E) to request the total number of separators, wells, or non-separator equipment in the basin used to calculate Calculation Method 3 storage tank emissions. The current language in 40 CFR 98.236(j)(2)(i)(E) requests the number of wells with gas-liquid separators in the basin, which is only a subset of the equipment included in the ‘‘Count’’ variable. Further, the EPA is proposing to remove the reporting requirement in 40 CFR 98.236(j)(2)(i)(F), which requires reporting of the number of wells without gas-liquid separators in the basin. Both of the current data elements in 40 CFR 98.236(j)(2)(i)(E) and 40 CFR 98.236(j)(2)(i)(F) have been determined to be no longer as useful for present program or policy purposes, as they do not correlate with the calculated Calculation Method 3 atmospheric tank emissions. These changes would streamline the requirements for all facilities reporting atmospheric storage tanks emissions using Calculation Method 3. Consistent with section II.B.3 of this preamble, reporters would no longer be required to determine two separate counts that may not be representative of the inputs used in equation W–15.

In addition, the provisions in 40 CFR 98.236(j)(2)(ii) and (iii) require facilities to separately report Calculation Method 3 emissions from atmospheric storage tanks that did not control emissions with flares and those that controlled emissions with flares, respectively. Using the calculation procedures provided in 40 CFR 98.233(j)(3) through (5), when a facility adds a flare control to an atmospheric storage tank in the middle of a reporting year, facilities are required to separately calculate emissions that are not flared from emissions that are flared from that tank, sum these emissions values, and report all emissions from the tank as part of the sub-basin or county flared tanks total per the requirements of 40 CFR 98.236(j)(2)(iii). In an effort to streamline and improve implementation consistent with section II.B.2 of this preamble, the EPA is proposing to clarify that for storage tanks using Calculation Method 3, reporters would calculate either flared or vented emissions for a tank, but not both. Specifically, the EPA is proposing to add language in 40 CFR 98.233(j)(5) that specifies that if the flare captured flash gas from at least half of the annual hydrocarbon liquids received by the tank for which emissions were calculated using Calculation Method 3, flared emissions would be calculated according to 40 CFR 98.233(j)(5) (*i.e.,* as if all flash gas generated from a tank during the entire reporting year is sent to a flare). The EPA is also proposing to amend 40 CFR 98.236(j)(2)(iii) to specify that the reporting requirements in that section only apply to tanks whose emissions were calculated using Calculation Method 3 that used flares to control emissions from at least half the annual hydrocarbon liquids received. The EPA is proposing a corresponding change to 40 CFR 98.236(j)(2)(ii), which would require reporting of the Calculation Method 3 emissions from the remaining atmospheric storage tanks that either used flares to control emissions from less than half the annual hydrocarbon liquids received or did not control any emissions with a flare. The emissions from these remaining atmospheric storage tanks would be calculated as venting directly to the atmosphere for the entire year (*i.e.,* emissions from tanks that flared for less than half of the year would not be calculated using the flare procedures provided in 40 CFR 98.233(j)(5)).

d. Flared Transmission Storage Tank Vent Emissions

Reporters in the transmission compression industry segment currently are required to report flared emissions specific to their transmission storage tanks separately from other flare stack emissions. In the years RY2015 through RY2020, between one and six facilities per year reported having a transmission tank vent stack routed to a flare, and each of these facilities reported no leaks. As a result, the reported flared emissions from transmission storage tank vent stacks in each of the last 6 years have been 0 metric tons of CO_2, CH_4, and N_2O. Based on these results, the EPA has made a preliminary determination that continued reporting of source-specific flared emissions from transmission tanks would not likely provide new insights or knowledge of the industry sector, emissions, or trends. Therefore, consistent with section II.B.3 of this preamble, the EPA is proposing that transmission tanks be classified as a miscellaneous flared source such that any flared emissions from the tanks in the future would be reported collectively with flared emissions from all miscellaneous flared sources as specified in 40 CFR 98.236(n)(1). The EPA is proposing to retain the current requirements in 40 CFR 98.233(k)(1) and (2) to monitor the tank vent stack annually for leaks and to quantify the leak rate if a leak is detected. As an alternative to these source-specific requirements, a reporter also would be allowed to continuously measure either total flow from the transmission tank vent stack or the comingled total flow into the flare, consistent with the existing requirement in 40 CFR 98.233(n)(1). Flow data determined by either of these methods would still be needed to calculate total flared emissions from the miscellaneous flared sources. Reporting requirements would remain essentially the same except that flared mass emissions would no longer be reported under 40 CFR 98.236(k)(3). Note that if we decide not to finalize the proposed changes described in this section after considering public comment, then we alternatively propose that we would finalize flare activity data reporting requirements for flared emissions from transmission storage tank vent stacks consistent with the activity data reporting for other source types that have source-specific flared emissions reporting requirements as described in the ‘‘Calculation Methodology for Flared Emissions’’ subsection in section III.J.1.i of this preamble. The proposed rule language under this alternative would be added to 40 CFR 98.233(k)(5), and it would be similar to proposed language for other flared sources (*e.g.,* well testing in 40 CFR 98.233(l)(6) and associated gas flaring in 40 CFR 98.233(m)(5)). One difference is that an option to continuously measure combined streams into a flare would not be allowed for transmission tanks because it would not be possible to tell if there were any scrubber dump valve leaks if only a combined emissions stream is measured. We request comment on the advantages and disadvantages of both approaches we are considering relative to the current requirements.

e. Compressors

As noted in section III.J.1.j of this preamble, reporting requirements for compressors in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment industry segments include requirements to conduct ‘‘as found’’ measurements for the compressor mode-source combination in which the compressor is found. In addition, if a given compressor was not measured in not-operating-depressurized-mode during the ''as found'' measurements for three consecutive years, a measurement in not-operating-depressurized-mode is currently required to be taken during the next planned scheduled shutdown of the compressor, per 40 CFR 98.233(o)(1)(i)(C) and (p)(1)(i)(D). This provision requires reporters to schedule an extra ''as found'' measurement to make this required measurement if the compressor was not found in this mode when the regularly scheduled ''as found'' measurements were taken.

We are proposing to eliminate this requirement to conduct a measurement in not-operating-depressurized-mode at least once every three years, consistent with section II.B.2 of this preamble. We originally included this requirement in subpart W in order to obtain a sufficient amount of data for this mode (75 FR 74458, November 30, 2010). However, based on data collected under subpart W thus far, many compressors are in not-operating-depressurized-mode for 30 percent of the time or more. As such, the extra measurements are unnecessary, and we are proposing to eliminate this requirement and make the annual ''as found'' measurements true ''as found'' measurements. We are also proposing to remove the reporting requirement to indicate if the compressor had a scheduled depressurized shutdown during the reporting year (40 CFR 98.236(o)(1)(xiv) and 40 CFR 98.236(p)(1)(xiv)) because that information is only collected to verify compliance with the requirement to conduct a measurement in not-operating-depressurized-mode at least once every three years.

In addition, centrifugal and reciprocating compressors are the only sources for which capture for fuel use and thermal oxidizers are specifically listed as dispositions for emissions that would otherwise be vented. The EPA's intent with the provisions is to differentiate flares, which are combustion devices that combust waste gases without energy recovery (per 40 CFR 98.238), from combustion devices with energy recovery, including for fuel use. However, some thermal oxidizers combust waste gases without energy recovery and therefore may instead meet the subpart W definition of flare. To avoid confusion, and to clarify that the EPA's intent is generally to treat emissions routed to flares and combustion devices other flares consistently, we are proposing to remove the references to fuel use and to thermal oxidizers in 40 CFR 98.233(o) and (p) and 40 CFR 98.236(o) and (p). Instead, we are proposing to define ''routed to combustion'' in 40 CFR 98.238 to specify the types of non-flare combustion equipment for which reporters would be expected to calculate emissions. In particular, for the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments, ''routed to combustion'' means the combustion equipment specified in 40 CFR 98.232(c)(22), (i)(7), and (j)(12), respectively (*i.e.,* the combustion equipment for which emissions must be calculated per 40 CFR 98.233(z)). For all other industry segments, ''routed to combustion'' means the stationary combustion sources subject to subpart C. The proposed definition of ''routed to combustion'' would apply for all subpart W emission sources for which that term appears (*e.g.,* natural gas driven pneumatic pumps).

Finally, we are proposing to remove some data elements that are redundant between 40 CFR 98.236(o)(1) and (2) for centrifugal compressors and between 40 CFR 98.236(p)(1) and (2) for reciprocating compressors. Specifically, 40 CFR 98.236(o)(1)(vi) and 40 CFR 98.236(p)(1)(vi) require reporters to indicate which individual compressors are part of a manifolded group of compressor sources, and 40 CFR 98.236(o)(1)(vii) through (ix) and 40 CFR 98.236(p)(1)(vii) through (ix) require reporters to indicate whether individual compressors have compressor sources routed to flares, vapor recovery, or combustion. However, 40 CFR 98.236(o)(2)(ii)(A) and 40 CFR 98.236(p)(2)(ii)(A) require the same information for each compressor leak or vent rather than by compressor. The information collected for each leak or vent is more detailed and is the information used for emissions calculations. Therefore, the EPA is proposing to remove the redundant reporting requirements in 40 CFR 98.236(o)(1)(vi) through (ix) and 40 CFR 98.236(p)(1)(vi) through (ix), consistent with section II.B.3 of this preamble.

f. Combustion

Subpart W refers reporters in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments to the calculation methodologies in subpart C to determine combustion emissions for certain fuels. Specifically, 40 CFR 98.233(z)(1) specifies that reporters may use any tier of subpart C if the fuel combusted is listed in Table C–1; the paragraph further specifies that the subpart C methodologies may only be used for fuel meeting the definition of ''natural gas'' in 40 CFR 98.238 if it is also of pipeline quality specification and has a minimum HHV of 950 Btu per standard cubic foot (Btu/scf). If the fuel is natural gas that does not meet these criteria, field gas, process vent gas, or a blend containing field gas or process vent gas, 40 CFR 98.233(z)(1) specifies that the procedures in 40 CFR 98.233(z)(2) should be used to calculate combustion emissions. Stakeholders (*e.g.,* GPA Midstream) have identified several concerns with these requirements. In general, they have stated that the ability to use subpart C calculation methodologies is unclear and too restrictive. We are proposing several amendments to these provisions to address these concerns and increase the flexibility of the calculation methods, consistent with section II.B.2 of this preamble.

First, GPA Midstream has indicated that it is not clear whether field gas that is of pipeline quality meets the criteria to use the subpart C methodologies under 40 CFR 98.233(z)(1),[104] and ''field gas'' is not defined within subpart W or subpart A (General Provisions). The terms ''field gas'' and ''field quality'' are frequently used interchangeably by the industry, but the EPA also recognizes that some streams in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment that industry would generally call ''field gas'' can be natural gas (as defined in 40 CFR 98.238) of pipeline quality with a minimum HHV of 950 Btu/scf. GPA Midstream stated that the procedures in 40 CFR 98.233(z)(2) are more burdensome than the subpart C methodologies and asked that the EPA clarify that ''field gas'' streams of pipeline quality can use the subpart C methodologies. After review of these comments, the EPA is proposing to revise 40 CFR 98.233(z)(1) to remove the references to field gas and process vent gas and include only the characteristics for the fuels that can use subpart C methodologies. The EPA's intent is to clarify that a stream colloquially referred to as ''field gas'' that otherwise meets the three criteria to use the subpart C methodologies for combustion emissions (*i.e.,* (1) meets the definition of ''natural gas'' in 40 CFR 98.238; (2) is of pipeline quality specification; and (3) has a minimum HHV of 950 Btu/scf) may use subpart C methodologies. The

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[104] Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

EPA is also proposing conforming edits to 40 CFR 98.233(z)(2) (proposed to be moved to 40 CFR 98.233(z)(3)) for consistency.

Second, reporters have indicated in questions submitted to the GHGRP Help Desk that the term ''pipeline quality'' is also not defined in subpart W, leading to confusion over whether some fuel streams meet the criteria to use the subpart C calculation methodologies per 40 CFR 98.233(z)(1). In addition, GPA Midstream has opined that the emissions calculated using subpart C and subpart W calculation methodologies are similar for many fuel streams that are not natural gas of pipeline quality specification with a minimum HHV of 950 Btu/scf. Therefore, they have suggested that the EPA should allow subpart C calculation methodologies to be used for a wider variety of fuels (if not all fuels in the segments that report combustion emissions under subpart W).[105]

We have reviewed the analysis in GPA Midstream's May 18, 2016 letter and conducted our own analysis of additional hypothetical fuel compositions. In general, we observed that the agreement of emissions as calculated using subpart C calculation methodologies for natural gas and using subpart W calculation methodologies varies based on the composition, with the largest differences resulting for fuel streams with high CO_2 content. We also observed that for these fuels, emissions calculated using subpart W calculation methodologies generally showed better agreement with emissions calculated using the subpart C calculation methodology for natural gas when using a site-specific HHV (Tier 2) than with emissions calculated using the subpart C calculation methodology that uses a default HHV (Tier 1). For more information on our fuel composition analysis and the comparison of emissions using various composition thresholds, see the subpart W TSD, available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

Based on our analysis, we are proposing to add numeric composition thresholds for natural gas to a new paragraph in 40 CFR 98.233(z)(2) that define the fuels for which an owner or operator may use subpart C methodologies. In particular, we are proposing that subpart C methodologies Tier 2 or higher may be used for fuel meeting the definition of ''natural gas'' in 40 CFR 98.238 if it has a minimum HHV of 950 Btu/scf, a maximum CO_2 content of 1 percent by volume, and a minimum CH_4 content of 85 percent by volume. We are not proposing to amend the existing provisions in 40 CFR 98.233(z)(1) that allow the use of any subpart C calculation methodology for natural gas of pipeline quality specification with a minimum HHV of 950 Btu/scf (with the clarifications noted earlier in this section). We are also proposing to move the existing provisions for fuels that do not meet the specifications to use subpart C methodologies from 40 CFR 98.233(z)(2) to a new paragraph 40 CFR 98.233(z)(3). This proposed amendment would allow reporters to use subpart C methodologies for a wider variety of fuel streams while still ensuring data quality. We request comment on the natural gas specifications included in proposed 40 CFR 98.233(z)(2), including the values proposed for the maximum CO_2 content and minimum CH_4 content, as well as whether additional specification criteria should be included (*e.g.,* a maximum HHV).

Third, we are proposing amendments to clarify that emissions may be calculated in 40 CFR 98.233(z)(3)(ii) for groups of combustion units. The current provisions of 40 CFR 98.233(z)(2) (proposed to be moved to 40 CFR 98.233(z)(3)(ii)) could be interpreted to specify that emissions must be calculated for each individual combustion unit. However, because combustion emissions and activity data are reported as combined totals for each type of combustion device and fuel, it is not necessary to calculate emissions for each individual unit before aggregating the total emissions. For example, if the volume of fuel combusted is determined at a single location upstream of several combustion units with similar combustion efficiencies, emissions may be determined for that combined volume of fuel (*i.e.,* for that group of combustion units). In other words, it is not necessary in this case to apportion a volume of fuel to each unit, calculate emissions separately, and then combine them again. If the combustion units downstream of this shared measurement point are a mix of combustion device types, the emissions and the volume of fuel would still need to be apportioned between those combustion device types for reporting purposes; however, reporters may elect to perform that apportioning either before or after emissions are calculated, as appropriate, as long as the group of combustion units does not include any natural gas-driven compressor drivers. If any of the combustion units downstream of this shared measurement point are natural gas-driven compressor drivers, the volumes of fuel for those units would have to be separated from the total before emissions are calculated to account for the differences in combustion efficiency, as described in section III.J.1.n of this preamble.

g. Onshore Natural Gas Processing and Natural Gas Distribution Throughput Information

Onshore Natural Gas Processing plants are required to report seven facility-level throughput-related items under subpart W, as specified in 40 CFR 98.236(aa)(3). These seven data reporting elements include: quantities of natural gas received and processed gas leaving the gas processing plant, cumulative quantities of NGLs received and leaving the gas processing plant, the average mole fractions of CH_4 and CO_2 in the natural gas received, and an indication of whether the facility fractionates NGLs. Natural Gas Distribution companies are also required to report seven throughput volumes under subpart W, as specified in 40 CFR 98.236(aa)(9). These seven data reporting elements include: the quantity of gas received at all custody transfer stations; the quantity of natural gas withdrawn from in-system storage; the quantity of gas added to in-system storage; the quantity of gas delivered to end users; the quantity of gas transferred to third parties; the quantity of gas consumed by the LDC for operational purposes; and the quantity of gas stolen.

The EPA has received stakeholder comments, including from the American Gas Association (AGA),[106] related to some of these reporting elements. Stakeholders have commented that the reporting elements included in subpart W are redundant with data reported elsewhere within the GHGRP, specifically under subpart NN (Suppliers of Natural Gas and Natural Gas Liquids). Subpart NN requires NGL fractionators and LDCs to report the quantities of natural gas and natural gas

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[105] See Letter from GPA Midstream Association to Mark de Figueiredo, U.S. EPA, providing information in response to EPA questions during the meeting on March 23, 2016. May 18, 2016. See also Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Both letters are available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[106] See Docket Id. Nos. EPA–HQ–OA–2017–0190–46726, EPA–HQ–OA–2017–0190–1958, EPA–HQ–OA–2017–0190–2066 available in *Compilation of Comments Related to the Greenhouse Gas Reporting Program submitted to the Department of Commerce under Docket ID No. DOC–2017–0001 and the Environmental Protection Agency under Docket ID No. EPA–HQ–OA–2017–0190* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

liquid products supplied downstream and their associated emissions. For example, for natural gas processing plants, both subparts require reporting of the volume of natural gas received and the volume of NGLs received. Subpart W also requires reporting of total NGLs leaving the processing plant, while subpart NN requires reporting of the volume of each individual NGL product supplied. For LDCs, some duplicative reporting is required as well. For example, both subparts require reporting of the volume of natural gas received, volume placed into and out of storage each year, and volume transferred to other LDCs or to a pipeline as well as some other duplicative data. In addition, commenters stated that the reporting elements included in subparts W and NN for LDCs are redundant with data reported to the U.S. Energy Information Administration (EIA) on Form EIA–176, the Annual Report of Natural and Supplemental Gas Supply and Disposition.[107] The commenters explained that subpart W and subpart NN collect nearly the same data, and discrepancies between the data sets are due to the use of inconsistent terminology. Commenters also suggested that due to the redundancy and availability of data reported to the EIA for LDCs, the EPA should remove the throughput-related reporting requirements for the Natural Gas Distribution industry segment from the GHGRP altogether. Commenters added that if the requirements are maintained, the EPA should reconcile the terminology used within the GHGRP and clarify the reporting elements.

The EIA report is submitted in the spring of each year and covers the previous calendar year. After completing internal audits of the reports, EIA publishes the data for each LDC on its website in the fall. The EIA data provides detailed information on the volume of gas received, gas stored, gas removed from storage, gas deliveries by sector, and HHV data. The EPA previously reviewed the possibility of obtaining data by accessing existing federal government reporting and ''decided not to modify the final rule because collecting data directly in a central system will enable the EPA to electronically verify all data reported under this rule quickly and consistently, to use the information for non-statistical purposes, and to handle confidential business information in accordance with the Clean Air Act.'' [108] In the specific case of subpart NN, in the 2009 Final Rule, the EPA also ''determined that it could not rely on EIA data to collect facility-level data from fractionators and company-level data from LDCs.'' Additionally, the EPA sought ''data that is beyond what EIA collects, such as quality assurance information, verification data, and information on odorized propane'' and ''data on site-specific HHV and carbon content from those sites that choose to sample and test products rather than use default emission factors.''

After further review of the data available through EIA, the stakeholder comments described earlier in this section, and the reporting requirements in subpart W and subpart NN, the EPA is proposing to eliminate duplicative elements from subpart W for facilities that report to subpart NN, consistent with section II.B.3 of this preamble. The EPA is proposing to amend the reporting requirements in 40 CFR 98.236(aa)(3) for Onshore Natural Gas Processing plants that fractionate NGLs (approximately 100 of the 450 subpart W natural gas processing plants) and also report as a supplier under subpart NN. For this subset of facilities, the EPA reviewed the data from subpart W and subpart NN and determined that there are no gas processing plants that report as fractionators under subpart W that do not also report under subpart NN without supplying a valid explanation.[109] During this review, the EPA found that some of the data elements included in subpart W overlap with data elements in subpart NN. Specifically, the data elements in 40 CFR 98.236(aa)(3)(i), (iii) and (iv) of subpart W overlap with data elements in subpart NN as specified in 40 CFR 98.406(a)(3), 98.406(a)(1) and (2), 98.406(a)(4)(i) and (ii), respectively.[110]

To eliminate reporting redundancies, the EPA is proposing6 several amendments to 40 CFR 98.236(aa)(3). First, to clarify which facilities have data overlap between subparts W and NN, the EPA is proposing to add a reporting element for natural gas processing plants at 40 CFR 98.236(aa)(3)(viii) to indicate whether they report as a supplier under subpart NN. Next, the EPA is proposing that facilities that indicate that they both fractionate NGLs and report as a supplier under subpart NN would no longer be required to report the quantities of natural gas received or NGLs received or leaving the gas processing plant as specified in 40 CFR 98.236(aa)(3)(i), (iii) and (iv). These facilities would, however, be required to continue reporting the data elements specified in 40 CFR 98.236(aa)(3)(ii) and (v) through (viii), as these reporting elements do not overlap with subpart NN reporting elements. Natural gas processing plants that do not fractionate or that fractionate but do not report as a supplier under subpart NN would continue to report all of the reporting elements for natural gas processing plants as specified in 40 CFR 98.236(aa)(3).

The EPA is also proposing to remove the reporting elements for throughput for LDCs in 40 CFR 98.236(aa)(9). The EPA reviewed the data from subpart W and subpart NN and determined that there are no LDCs that report under subpart W that do not also report under subpart NN. In fact, an average of 385 LDCs report under subpart NN, while 170 LDCs report under subpart W. Subpart NN therefore provides more comprehensive coverage of the Natural Gas Distribution industry segment. Additionally, subpart NN has been in effect for LDCs since RY2011 while subpart W throughput information has only been collected since RY2015; thus, subpart NN has a more robust historical data set. During this review, the EPA determined that the data elements found in 40 CFR 98.236(aa)(9)(i) through (v) of subpart W overlap with data elements in subpart NN as specified in 40 CFR 98.406(b)(1) through (3), 98.406(b)(5) and (6), and 98.406(b)(13). To eliminate reporting redundancies, the EPA is proposing to remove these reporting elements from subpart W.

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[107] Form EIA–176 is available at the U.S. EIA website at *https://www.eia.gov/survey/form/eia_176/form.pdf;* the Form EIA–176 Instructions are available at *https://www.eia.gov/survey/form/eia_176/instructions.pdf.*

[108] See page 7 of *EPA Response to Public Comment Vol. 39 Subpart NN* at *https://www.epa.gov/ghgreporting/ghgrp-2009-final-rule-response-comments-documents,* also available in the docket for this rulemaking, Docket Id. No EPA–HQ–OAR–2019–0424.

[109] One such explanation is that the gas processing plant fractionates NGLs to supply fuel for use entirely on-site (*i.e.,* the fuel is not supplied downstream). Due to definitional differences between the two subparts, this facility is defined as a fractionator for purposes of subpart W but is not a supplier that must report under subpart NN.

[110] While it is the EPA's intention that the reported quantity of natural gas received at the facility in 40 CFR 98.236(aa)(3)(i) should be the quantity of natural gas received for processing, consistent with the requirement to report the annual volume of natural gas received for processing in 40 CFR 98.406(a)(3), some reporters have indicated in correspondence with the EPA via e-GGRT that they are including gas that is received at but not processed by the onshore natural gas processing facility (*i.e.,* gas that was processed elsewhere and passes through the onshore natural gas processing facility). Therefore, to clarify the EPA's intention and reinforce the consistency of the subpart W and subpart NN quantities, the EPA is proposing to revise 40 CFR 98.236(aa)(3)(i) to indicate that that reported quantity should be natural gas received at the gas processing plant for processing in the calendar year.

The EPA is also proposing to remove the reporting elements for the volume of natural gas used for operational purposes and natural gas stolen specified in 40 CFR 98.236(aa)(9)(vi) and (vii). These reporting elements are unique to subpart W and have caused confusion for subpart W reporters, require additional burden to estimate, and have not been used for the EPA's analyses of the subpart W data. As a result of removing these data elements, the EPA proposes to reserve paragraph 40 CFR 98.236(aa)(9). Table 2 of this preamble shows all the duplicative data elements that the EPA is proposing to remove from subpart W for facilities that also report to subpart NN.

TABLE 2—LIST OF PROPOSED SUBPART W DATA ELEMENTS TO BE REMOVED WHERE ANALOGOUS SUBPART NN DATA ELEMENTS ARE REPORTED

Subpart W data elements proposed to be eliminated		Analogous subpart NN data elements	
Citation	Description	Citation	Description
Local Distribution Companies.			
§ 98.236(aa)(9)(i)	Quantity of natural gas received at all custody transfer stations.	§ 98.406(b)(1) § 98.406(b)(5)	Annual volume of natural gas received by the LDC at its city gate stations and Annual volume natural gas that bypassed the city gate(s).
§ 98.236(aa)(9)(ii)	Quantity of natural gas withdrawn from in-system storage.	§ 98.406(b)(3)	Annual volume natural gas withdrawn from on-system storage and annual volume of vaporized LNG withdrawn from storage.
§ 98.236(aa)(9)(iii)	Quantity of natural gas added to in-system storage.	§ 98.406(b)(2)	Annual volume of natural gas placed into storage or liquefied and stored.
§ 98.236(aa)(9)(iv)	Quantity of natural gas delivered to end users.	§ 98.406(b)(13)(i) through (iv)	Annual volume of natural gas delivered by the LDC to residential consumers, commercial consumers, industrial consumers, electricity generating facilities.
§ 98.236(aa)(9)(v)	Quantity of natural gas transferred to third parties.	§ 98.406(b)(6)	Annual volume of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.
Natural Gas Processing Plants that Fractionate NGLs.			
§ 98.236(aa)(3)(i)	Quantity of natural gas received.	§ 98.406(a)(3)	Annual volume of natural gas received for processing.
§ 98.236(aa)(3)(iii)	Cumulative quantity of all NGLs (bulk and fractionated) received.	§ 98.406(a)(2) § 98.406(a)(4)(i)	Annual quantity of each NGL product received and annual quantities of y-grade, o-grade and other bulk NGLs received.
§ 98.236(aa)(3)(iv)	Cumulative quantity of all NGLs (bulk and fractionated) leaving.	§ 98.406(a)(1) § 98.406(a)(4)(ii)	Annual quantity of each NGL product supplied and annual quantities of y-grade, o-grade and other bulk NGLs supplied.

h. Onshore Natural Gas Processing Industry Segment

According to 40 CFR 98.230(a)(3), the Onshore Natural Gas Processing industry segment currently includes all facilities that fractionate NGLs. The industry segment also includes all facilities that separate NGLs from natural gas or remove sulfur and CO_2 from natural gas, provided the annual average throughput at the facility is 25 MMscf per day or greater. The industry segment also includes all residue gas compression equipment owned or operated by natural gas processing facilities that is not located within the facility boundaries.

GPA Midstream has expressed concern that the current definition of the Onshore Natural Gas Processing industry segment applies to some compressor stations simply because they have an amine unit that is used to remove sulfur and CO_2 from natural gas. According to GPA Midstream, it would be more appropriate for such facilities to be in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. GPA Midstream also explained that the 25 MMscf per day threshold creates additional burden and uncertainty for these compressor station facilities because they do not know until the end of the year whether they will be above or below the threshold. Thus, they need to collect the applicable data for both the Onshore Natural Gas Processing industry segment and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment so that they will have the required data for whichever industry segment ultimately applies to them. To resolve this issue and to promote consistency among regulatory programs, GPA Midstream recommended replacing the onshore natural gas processing definition in subpart W with the natural gas processing plant definition in NSPS OOOOa.[111]

After review of these comments, we are proposing to replace the definition of ''Onshore natural gas processing'' in 40 CFR 98.230(a) with language similar to the definition of ''natural gas processing plant'' in NSPS OOOOa. NSPS OOOOa defines ''natural gas processing plant (gas plant)'' as any processing site engaged in the extraction of NGLs from field gas, fractionation of mixed NGLs to natural gas products, or both. The definition specifies that a Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant. There are two minor editorial differences between

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[111] Letter from Matt Hite, GPA Midstream Association, to Mark de Figueiredo, U.S. EPA, Re: Additional Information on Suggested Part 98, Subpart W Rule Revisions to Reduce Burden. September 13, 2019. Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

the proposed definition in 40 CFR 98.230(a) and the definition in NSPS OOOOa. First, instead of defining a natural gas processing ''plant,'' as in the definition in NSPS OOOOa, we are proposing to describe what is meant by ''natural gas processing'' so that the structure of 40 CFR 98.230(a)(3) is consistent with the structure of all of the other industry segment definitions in 40 CFR 98.230(a). Second, the definition in NSPS OOOOa refers to ''extraction'' of NGLs from natural gas, but this term is not defined. Thus, we are proposing to retain the term ''forced extraction'' in the current provisions of 40 CFR 98.230(a)(3) and revise the definition of this term slightly in 40 CFR 98.238. The current definition of ''forced extraction'' specifies that forced extraction does not include ''portable dewpoint suppression skids.'' We are proposing to revise the definition to indicate instead that forced extraction does not include ''a Joule-Thomson valve, a dewpoint depression valve, or an isolated or standalone Joule-Thomson skid.'' These changes would make the definition of ''forced extraction'' in subpart W consistent with the language in the definition of a natural gas processing plant in NSPS OOOOa. This proposed amendment would provide reporters with certainty about the applicable industry segment for the reporting year, reducing the monitoring data they must collect to only the information needed for the applicable industry segment, consistent with section II.B.2 of this preamble.

This proposed amendment is not expected to decrease overall coverage of the GHGRP for the petroleum and natural gas systems industry, although we anticipate that some facilities would report under a different industry segment going forward. Based on reported data for RY2020, about 19 percent of facilities reporting in the Onshore Natural Gas Processing industry segment do not fractionate NGLs and report zero NGLs received and leaving the facility. These facilities meet the current definition of natural gas processing because they are separating CO_2 and/or hydrogen sulfide. These facilities would not meet the proposed revised definition for natural gas processing and instead, their emissions would be reported as part of either existing or new onshore petroleum and natural gas gathering and boosting facilities. In most cases, we anticipate that operations at a former gas processing facility would be incorporated into an existing gathering and boosting facility that has been subject to reporting, and the total emissions from the expanded gathering and boosting facility would be similar to the emissions that would have been reported by the separate facilities under the existing industry segment definitions. In cases where a former gas processing facility is located in a basin where the owner or operator does not have an existing reporting gathering and boosting facility, we expect that a new gathering and boosting facility including the former gas processing facility would be created because the emissions from the former gas processing facility alone would exceed the reporting threshold of 25,000 $mtCO_2e$. If the same owner or operator has other gathering and boosting operations in the same basin that have emissions less than 25,000 $mtCO_2e$, then the new gathering and boosting facility could result in increased coverage of the industry segment and greater total reported emissions than would be reported under the current industry segment definitions.

The proposed revised definition for natural gas processing also does not include the 25 MMscf per day threshold for facilities that do not fractionate NGLs. Under the current definition of onshore natural gas processing, processing plants that do not fractionate gas liquids and generally operate close to the 25 MMscf per day threshold do not know until the end of the year whether they will be above or below the threshold, so they must be prepared to report under whichever industry segment is ultimately applicable. The two potentially applicable segments report emissions from different sources and with different calculation methods. For example, facilities in the Onshore Natural Gas Processing industry segment are not required to report emissions from atmospheric storage tanks and are required to measure leaks from individual compressors, while facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment are required to report emissions from atmospheric storage tanks but may use emission factors to calculate emissions from compressors rather than conducting measurements. These sites would meet the revised proposed definition of natural gas processing regardless of their throughput level, so they would have the certainty of knowing they would be subject to reporting as natural gas processing facilities every year, and as a result, removing the 25 MMscf per day threshold is expected to increase the number of facilities that report under the Onshore Natural Gas Processing industry segment. We request comment on the impact the proposed change would have on the number of reporting facilities and emissions from both the Onshore Natural Gas Processing and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. We also request comment on any other advantages or disadvantages to finalizing the proposed change.

Finally, we note that the definition of natural gas processing plant in NSPS OOOOa does not specifically include residue gas compression equipment. Residue gas compression is defined in 40 CFR 98.238 as the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline. Per 40 CFR 98.230(a)(3), the Onshore Natural Gas Processing industry segment includes all residue gas compression equipment owned or operated by the natural gas processing plant. We are requesting comment on whether to remove the existing requirement to include residue gas compression equipment owned or operated by the natural gas processing facility from 40 CFR 98.230(a)(3) and 40 CFR 98.231(b). If this change were finalized, we anticipate that residue gas compression equipment would then be part of the Onshore Natural Gas Transmission Compression industry segment, which would require reporters with residue gas compression equipment that currently only report under the Onshore Natural Gas Processing industry segment to begin reporting under both the Onshore Natural Gas Processing and Onshore Natural Gas Transmission Compression industry segments in order to fully report their facility emissions. As part of the request for comment on this issue, we request comment on the expected impact on the level of reported emissions that would result if this change were finalized. We also request comment on other rationale for or against finalizing this change.

3. Other Proposed Minor Revisions or Clarifications

See Table 3 of this preamble for the miscellaneous minor technical corrections not previously described in this preamble that we are proposing throughout subpart W, consistent with section II.A.5 of this preamble.

TABLE 3—PROPOSED TECHNICAL CORRECTIONS TO SUBPART W

Section (40 CFR)	Description of proposed amendment
98.232(b), 98.233(s), 98.236(s)	Update the outdated acronym “BOEMRE” to the current acronym “BOEM.”
98.232(b), 98.233(s)	Update the cross references to the BOEM requirements from “30 CFR 250.302 through 304” to “30 CFR 550.302 through 304.”
98.233(a)(1)	Revise the definition of the equation variable “EF_t” to consolidate the list of applicable industry segments and tables into one sentence.
98.233(e)(1)(x)	Add “at the absorber inlet” to the end of the paragraph to clarify the location for the wet natural gas temperature and pressure to be used for modeling.
98.233(g)(4)(ii)	Revise the instance of “formation on N_2O” in the second sentence to read “formation of N_2O” to correct a typographical error.
98.233(j), 98.236(j)	Revise the instances of “oil,” “oil/condensate,” and “liquid” to read “hydrocarbon liquids” for consistency with the requirement in 40 CFR 98.233(j) to calculate emissions from “atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids,” as noted in the 2015 amendments to subpart W (80 FR 64272, October 22, 2015).
98.233(n)(5)	Correct the cross reference in the definition of the equation variable “Y_j” from paragraph (n)(1) to (n)(2).
98.233(o) introductory text and (p) introductory text.	Moved the last sentence in each paragraph to be the second sentence to clarify that the calculation methodology for compressors routed to flares, combustion, and vapor recovery apply to all industry segments.
98.233(p)(1)(i)	Correct the internal cross reference from paragraph (o) to paragraph (p).
98.233(p)(4)(ii)(C)	Add missing “in” to read “according to methods set forth in § 98.234(d).”
98.233(r) introductory text	Revise the instance of “CH” in the third sentence to read “CH_4” to correct a typographical error.
98.233(r), equations W–32A and W–32B	Correct the cross reference in the definition of the equation variable “$_{Es,MR,i}$” and the equation variable “$Count_{MR}$” from paragraph (q)(9) to (q)(2)(xi).
98.233(r)(6)(ii)	Add reference to components listed in 40 CFR 98.232(i)(3), for consistency with proposed amendments to 40 CFR 98.233(r)(6)(i).
98.233(s)	Remove the outdated references to “GOADS.”
98.233(t)(2)	Revise the definition of equation variable “Z_a” to include the sentence following the definition of that variable to correct a typographical error.
98.233(u)(ii)	Format the heading to be in italicized text.
98.233(z)	Revise the instances of “high heat value” to read “higher heating value” to correct inconsistency in the term.
98.233(z), equations W–39A and W–39B	Remove unnecessary “constituent” from “CO_2 constituent” and “methane constituent” and remove “gas” from “gas hydrocarbon constituent.” Add missing “the” to read “to the combustion unit” in several variable definitions.
98.236 introductory text	Add missing “than” to read “report gas volumes at standard conditions rather than the gas volumes at actual conditions.”
98.236(e)(2)	Revise the instances of “vented to” a control device, vapor recovery, or a flare to read “routed to” to correct inconsistency in the phrases “vented to” and “routed to.” Revise the instances of “vapor recovery device” to read “vapor recovery system” to correct inconsistency in the term.
98.236(j)(2)	Clarify that the reported information in paragraphs (j)(1)(i) through (xvi) should only include those atmospheric storage tanks with emissions calculated using Calculation Method 3.
98.236(l)(1), (2), (3), and (4) introductory text	Revise the instances of “vented to a flare” to read “routed to a flare” to correct inconsistency in the phrases “vented to” and “routed to.”
98.236(p)(3)(ii)	Add a missing period at the end of the sentence.
98.236(bb)	Clarify that reporting for missing data procedures includes the procedures used to substitute an unavailable value of a parameter (per 40 CFR 98.235(h)).
98.236(cc)	Correct the cross references from paragraph (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), and (l)(4)(iii) to (l)(1)(v), (l)(2)(v), (l)(3)(iv), and (l)(4)(iv), respectively.
98.238	Remove the second definition of “Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements” to eliminate an inadvertent identical duplicative definition.
Table W–1A, Table W–3B, and Table W–4B to subpart W of part 98.	Change “Low Continuous Bleed Pneumatic Device Vents” to “Continuous Low Bleed Pneumatic Device Vents” and change “High Continuous Bleed Pneumatic Device Vents” to “Continuous High Bleed Pneumatic Device Vents” to be consistent with the terms used throughout the rest of subpart W.
Table W–3B and Table W–4B to subpart W of part 98.	Change table headings and footnotes to clarify that the population emission factors for pneumatic device vents are whole gas emission factors rather than total hydrocarbon emission factors.

4. Best Available Monitoring Methods

The EPA is proposing that facilities would be allowed to use BAMM on a short-term transitional basis for the proposed amendments for the 2023 reporting year for only the specific industry segments and emission sources for which new monitoring or data collection requirements are being proposed. These industry segments and emission sources include calculating and reporting emissions from natural gas pneumatic devices at onshore natural gas processing facilities, natural gas intermittent bleed pneumatic devices for which the reporter conducts routine monitoring surveys, acid gas removal vents at LNG import/export facilities, other large release events at all facilities, miscellaneous flared sources, glycol dehydrators and atmospheric storage tanks routed to vapor recovery systems, compressor sources and mode-source combinations for which new measurements would be required, and measurements taken using a high volume sampler. We are also proposing that reporters of an onshore natural gas processing facility that becomes part of an onshore petroleum and natural gas gathering and boosting facility, or vice versa, solely due to the proposed change in the definition of 40 CFR 98.230(a)(3) would be allowed to use BAMM for the emission sources for which measurements were not required under the previous industry segment. This proposal would allow reporters to use best available methods to estimate inputs to emission equations for the newly proposed emission sources using their best engineering judgment for cases where the monitoring of these inputs would not be possible beginning on January 1, 2023.

These reporters would have the option of using BAMM from January 1, 2023, to December 31, 2023, without seeking prior EPA approval for certain parameters that cannot reasonably be measured according to the monitoring and quality assurance/quality control (QA/QC) requirements of 40 CFR 98.234. This additional time for reporters to comply with the monitoring methods for new emission sources in subpart W would allow facilities to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions. The EPA is not proposing to allow the use of BAMM beyond RY2023 and does not anticipate that BAMM would be needed beyond 2023 for the specific industry segments and emissions sources with proposed amendments in this rule. The EPA is also not proposing to allow the use of BAMM for industry segments and emission sources for which no amendments have been proposed that would require additional data collection because reporters should already be collecting the measurements and activity data needed to meet the requirements of the current rule.

K. Subpart X—Petrochemical Production

We are proposing several amendments to subpart X of part 98 (Petrochemical Production) to improve the quality of data reported and to clarify the calculation, recordkeeping, and reporting requirements for the reasons described in this section and in section II.A of this preamble.

For the reasons described in section II.A.3 of this preamble, we are proposing to add a reporting 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. These sections of subpart X currently require reporting of the total emissions from each flare that burns off-gas from a petrochemical process unit for which emissions are determined under the CEMS or optional ethylene combustion methodologies. We are proposing that reporters also report estimated fractions of the total CO_2, CH_4, and N_2O emissions from these flares that are due to combusting petrochemical off-gas because the current requirements result in an overestimate of emissions attributed to a petrochemical process unit when the flare is not dedicated to a petrochemical process unit, particularly if the flare is also used to combust off-gas from non-petrochemical process units. The proposed requirement would allow the fractions attributed to each petrochemical process unit that routes emissions to the flare to be estimated using engineering judgment. This proposed change would allow more accurate quantification of emissions both from individual petrochemical process units and from the industry sector as a whole.

For the reasons described in section II.A.4 of this preamble, we are proposing to add 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 under the optional ethylene combustion methodology. Subpart X currently requires reporting of only the quantity of ethylene produced. The proposed change would make product reporting under the optional ethylene combustion methodology consistent with product reporting requirements under the CEMS and mass balance reporting options. Data on the quantities of all products will improve the EPA's ability to verify reported emissions from these process units, and the data will be useful in informing future policy decisions.

For the reasons described in section II.A.5 of this preamble, we are proposing two changes to clarify emissions calculation requirements for flares. Currently, 40 CFR 98.243(b)(3) and (d)(5) cross-reference the calculation procedures in 40 CFR 98.253(b)(1) through (b)(3) of subpart Y. We are proposing to revise these sections to cross-reference all of 40 CFR 98.253(b) to clarify that the provisions added in past amendments and in this amendments package to the introductory paragraph in 40 CFR 98.253(b) also apply to flares that are subject to reporting under subpart X. This proposed change would clarify that subpart X reporters are not required to report emissions from combustion of pilot gas and, as discussed in section III.L of this preamble, that gas released during SSM events of <500,000 scf/day are excluded from equation Y–3.

Additionally, we are proposing five amendments to clarify subpart X rule language pertaining to reporting of required data elements. In previous rule amendments, we added requirements to report the annual quantity of each petrochemical product produced from each process unit. In making the changes, we inadvertently introduced some overlapping reporting requirements. First, to clarify the reporting requirements and eliminate confusion for facilities that use the mass balance approach, we are proposing to amend 40 CFR 98.246(a)(2) to remove the requirement to report feedstock and product names. The rule currently specifies in two places that a reporter using the mass balance methodology must report the feedstock and product names for a subject process unit. The requirement in 40 CFR 98.246(a)(2) is to report the ''names of products, and names of carbon-containing feedstocks.'' The requirement in 40 CFR 98.246(a)(12) is to report the ''(n)ame (. . .) of each carbon-containing feedstock included in equations X–1, X–2, and X–3 of § 98.243.'' The requirement in 40 CFR 98.246(a)(13) is to report the ''(n)ame (. . .) of each product included in equations X–1, X–2, and X–3.'' Although the language in 40 CFR 98.246(a)(2) is slightly different from the language in 40 CFR 98.246(a)(12) and (13), the scope of 40 CFR 98.246(a)(2) is identical to the collective scope of 40 CFR 98.246(a)(12) and (13). For example, all gaseous carbon-containing feedstocks must be entered in the equation X–1 calculation, all liquid carbon-containing feedstocks must be entered in the equation X–2 calculation, and all solid carbon-containing feedstocks must be entered in the equation X–3 calculation. Thus, the current requirement in 40 CFR 98.246(a)(12) to report the name of each carbon-containing feedstock used in any of the equations means all carbon-containing feedstocks must be reported, which is identical to the requirement in 40 CFR 98.246(a)(2) to report the names of carbon-containing feedstocks. A similar analysis applied to the products results in the conclusion that the current requirement in 40 CFR 98.246(a)(13) to report the name of each product used in any of the equations means all products must be reported, which is identical to the requirement in 40 CFR 98.246(a)(2) to report the names of products. Note that the rule does not specify reporting of ''carbon-containing'' products; this is unnecessary because the term ''product'' is defined in 40 CFR 98.248 to mean ''. . .carbon-containing outputs. . .'' To eliminate the redundancy, we are proposing to delete the requirement to report names of products and the names of carbon-containing feedstocks from 40 CFR 98.246(a)(2) because the same requirements are also included in 40 CFR 98.246(a)(12) for feedstocks and 40 CFR 98.246(a)(13) for products.

The second amendment to the mass balance reporting requirements is to revise 40 CFR 98.246(a)(5) and 40 CFR 98.246(a)(13) to clarify the petrochemical and product reporting requirements for integrated ethylene dichloride/vinyl chloride monomer (EDC/VCM) process units. In a letter received from Occidental Chemical Company titled ''Request to Consider IPCC Balanced EDC/VCM Process Studies and Data for the Elimination of e-GGRT Validation Messages at VCM Production Facilities Reporting Under Subpart X,'' dated July 10, 2015 (available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424), industry representatives indicated that an integrated EDC/VCM process unit is a continuous process in which the EDC is produced as an intermediate that is used in the production of VCM; purified EDC circulates to the VCM production portion of the process, and multiple recovery loops recycle unconverted EDC from the VCM operations to the EDC operations for purification. These streams that pass back and forth between the EDC and VCM portions of the integrated unit are not isolated and are not measured in a manner that would allow for accurate calculation of the amount of intermediate EDC produced. Since the amount of EDC produced as an intermediate in such process units may not be measured, subpart X was previously amended to allow reporters to consider the entire integrated EDC/VCM process unit to be the petrochemical process unit (proposal at 81 FR 2536, January 15, 2016; final at 81 FR 89188, December 16, 2016). At the same time, 40 CFR 98.246(a)(5) was amended to specify that the amount of intermediate EDC produced in such units and included in the total reported amount of EDC petrochemical produced could be based on either measurements or an estimate. In subsequent years, data reported under subpart X of the GHGRP indicated that some facilities with an integrated EDC/VCM process unit withdraw small amounts of the EDC as a separate product stream. The amendments in 2016 were silent on how to report the amount of any EDC that is withdrawn as a separate product from the integrated unit. The intent of the proposed changes is that the amount of EDC product not used as an intermediate would continue to be determined as it would be for a standalone EDC process unit, this amount of EDC product would be added to the amount of intermediate EDC, and the total would be reported under 40 CFR 98.246(a)(5) as the amount of EDC petrochemical produced by the integrated EDC/VCM process unit. To clarify this intent we are proposing to revise 40 CFR 98.246(a)(5) to specify that 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, 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 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 also proposing a harmonizing 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. Reporting as a product only the quantity of EDC not used in the VCM process is consistent with the boundary of the mass balance being around the integrated EDC/VCM process unit.

For facilities that use CEMS, we are proposing a third amendment 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. In previous amendments (81 FR 89188, December 16, 2016), reporting requirements related to the quantity of intermediate EDC for an integrated EDC/VCM process unit were added to the petrochemical quantity reporting requirements at 40 CFR 98.246(b)(8) for CEMS-monitored units that were identical to the reporting requirements added to 40 CFR 98.246(a)(5) that are discussed above for mass balance units. This 2016 language was added so that the reporting requirements would be the same under both the mass balance methodology and the CEMS methodology. However, an EDC manufacturer does not need to consider an integrated EDC/VCM process unit to be the petrochemical process unit when using CEMS since vent streams are directly monitored and thus recycle streams from the VCM to EDC process are not required to be quantified as with a mass balance unit. Under the mass balance option, the amount of product must be a measured value because the quantity is used in the emissions calculation equation; thus, we allowed the entire integrated unit to be considered the petrochemical process unit so the amount of VCM product could be the primary reported product, and it would be measured. Under the CEMS option, the product quantity is used only in data verification procedures and other data analyses, and the EPA has tentatively determined that, for these purposes, reporting an estimated value is an acceptable alternative to incurring the expense of modifying an integrated unit process unit so that measurements can be taken. Thus, we are proposing to revise 40 CFR 98.246(b)(8) 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 proposing a fourth amendment to 40 CFR 98.246(c)(4) to clarify that the names and annual quantities of feedstocks that must be reported would be limited to feedstocks that contain carbon. This proposed change will make the feedstock reporting requirement under the optional ethylene combustion methodology consistent with the feedstock reporting requirements under the mass balance and CEMS options.

The fifth proposed change to clarify the reporting requirements under subpart X consists of clarifying changes to 40 CFR 98.246(a)(15). Currently, this paragraph specifies that the annual average molecular weight must be reported for each gaseous feedstock and product. The proposed revision would 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. This change would be consistent with statements in the definitions of the terms for volume or mass in equation X–1. We are also proposing to rearrange the text in 40 CFR 98.246(a)(15) and split the paragraph into two sentences to improve clarity.

These proposed clarifying changes would pose no new monitoring, reporting, or recordkeeping requirements. We are also proposing related confidentiality determinations for the new or revised data elements, as discussed in section VI of this preamble.

L. Subpart Y—Petroleum Refineries

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

We are proposing several amendments to subpart Y of part 98 (Petroleum Refineries) to improve data collection, clarify rule requirements, and correct an error in the rule.

For the reasons described in section II.A.2 and II.A.4 of this preamble, we are proposing to amend some of the requirements for DCUs to improve data collection and our ability to perform verification of reported data for these emission sources. During the verification of DCU emissions, we noted a disproportionate number of facilities were messaged with potential emission errors that used mass measurements from company records to estimate the dry coke at the end of the coking cycle (as an alternative to estimating this quantity using Eq. Y–18a) in 40 CFR 98.257(b)(41). Through correspondence with facilities regarding these potential emission errors, we found that the some of the errors were due to reporters incorrectly determining the mass of coke at the end of the coking cycle on a wet basis rather than on a dry basis. This led to an erroneously high value being used for the M_{coke} input parameters to equation Y–18b, resulting in an unusually low value of M_{water} and subsequently lower-than-expected methane emissions. We also found that some of the errors were explained by the use of a facility-specific bulk density of coke that was sufficiently different from the default value used in EPA-estimated emissions to generate a potential error message. Finally, we found that some facilities indicated the coke may not be completely submerged by water due to initiating draining prior to atmospheric venting. Such activities undermine some of the underlying assumptions of the steam generation model being used to estimate DCU emissions. In order to improve the quality of data collected and our ability to ensure the reported data are accurate, we are proposing two amendments to the DCU provisions.

The first proposed amendment is designed to enhance the reporting and recordkeeping specifically for facilities using mass measurements from company records to estimate M_{coke}. Currently, facilities using mass measurements have less recordkeeping requirements than those facilities using equation Y–18a to estimate the quantity. Facilities using equation Y–18a are required to keep records of the drum outage, drum height, and the drum diameter as specified in 40 CFR 98.257(b)(42) through (44), while facilities using mass measurements from company records for M_{coke} do not have any related reporting or recordkeeping other than the recordkeeping requirement of the M_{coke} quantity in 40 CFR 98.257(b)(41). Therefore, we have limited data available by which to verify the reported dry mass of coke at the end of the cycle, M_{coke}. In order to perform more robust and consistent verification of all of these reported quantities in future years, we are proposing 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 subparagraphs would require these 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, ensuring the most consistent and accurate data are provided. We do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters, as these data are likely already available in existing company records. We are proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

The second amendment for DCUs we are proposing is to amend equation Y–18b in 40 CFR 98.253(i)(2) to include a new variable ''f_{coke}'' and revise the existing descriptions of the ''M_{water}'' output and ''H_{water}'' variable. As noted in the discussion, some of the facilities messaged for potential emission errors explained that the coke was not completely submerged at the time the vessel is vented to the atmosphere, which contradicts assumptions underlying the calculation methodology. First, we are proposing to revise the definitions of ''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. The steam generation model requires a complete accounting of the heat within the unit prior to venting or draining since steam generation will occur if superheated water is drained from the unit prior to venting. We are also proposing similar revisions to the recordkeeping requirements at 40 CFR 98.257(b)(45) and (46) to add the phrase ''or draining'' to the description of the records. We are also proposing to add a new variable ''f_{coke}'' to equation Y–18b 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 would be 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 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. It is subtracted from the water-filled coke bed volume to determine the volume of water. If the coke bed is not completely submerged in the water, subtracting the entire volume of coke from the water-filled coke bed volume will underestimate the actual volume of water in the coke drum vessel, resulting in an underestimate of the methane emissions. Adding the ''f_{coke}'' variable to the second term in equation Y–18b would make the equation universally applicable in cases where the coke bed is not fully submerged when the coke drum is first vented or drained. We are also proposing to add a corresponding recordkeeping requirement at 40 CFR 98.257(b)(53).

We are proposing several clarifying changes, for the reasons described in section II.A.5 of this preamble. We are proposing to add clarifying language to 40 CFR 98.253(c) and 98.253(e) to reiterate the language from 40 CFR 98.252(b) that the emissions being quantified in these paragraphs are coke burn-off emissions rather than emissions that may occur from other venting events. The language at 40 CFR 98.252(b) clearly indicates that the emissions to be reported are ''. . . *coke burn-off* emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit . . . '' [emphasis added]. However, the language at to 40 CFR 98.253(c) and 98.253(e) could be construed to apply to other vented emissions. We have received a GHGRP Help Desk question concerning the applicability of the calculation methodology to other venting events. 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 proposing to add ''from coke burn-off'' immediately after the first occurrence of ''emissions'' in the introductory text of 40 CFR 98.253(c) and 40 CFR 98.253(e).

We are proposing a clarifying change to correct an inconsistency introduced into subpart Y by the amendments published on December 9, 2016 (81 FR 89188). The introduction to the flare emission calculation requirements at 40 CFR 98.253(b) was revised in 2016 to state that all gas discharged through the flare stack must be included in the calculations except for pilot gas. The intent of this provision was to require inclusion of purge and sweep gas in addition to SSM events. However, because equation Y–3 excludes SSM events less than 500,000 scf/day, the new provision created an apparent inconsistency about whether to include or exclude SSM events less than 500,000 scf/day in equation Y–3. Some reporters have interpreted that such SSM events must be included. We are proposing to clarify 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). This proposed clarification corrects the 2016 amendment, which was not intended to eliminate the exclusion when reporters use equation Y–3, and would reduce repeated verification and correction of errors submitted in reports.

We are proposing a correction to an erroneous cross-reference in 40 CFR 98.253(i)(5) for the reasons described in this section and section II.A.5 of this preamble. The section inaccurately defines the term M_{stream} in equation Y–18f for DCUs. Currently, M_{stream} is defined as, ''Mass of steam generated and released per decoking cycle (metric tons/cycle) as determined in paragraph (i)(3) of this section.'' The correct cross-reference is paragraph (i)(4) instead of (i)(3). The proposed change would not have any impact on burden.

Finally, we are proposing a change to correct an inconsistency introduced into subpart Y by the amendments published on December 9, 2016 (81 FR 89188). The DCU emission calculations were updated in 2016, and, as part of that update, 40 CFR 98.253(j) was revised to remove the option to calculate CH_4 emissions from DCUs using the process vent method (equation Y–19). However, the DCU recordkeeping requirements for the process vent method at 40 CFR 98.257(b)(53) through (56) were inadvertently not removed from the rule. We are proposing to revise 40 CFR 98.257(b)(53) to include recordkeeping requirement for the ''f_{coke}'' variable, as previously discussed in this section, and to remove and reserve the recordkeeping requirements in paragraphs 98.257(b)(54) through (56) since equation Y–19, the process vent calculation method, is no longer used to calculate DCU emissions.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart Y

For the reasons described in this section and in section II.B.2 of this preamble, we are proposing to allow the use of mass spectrometer analyzers to determine gas composition and molecular weight without the use of a gas chromatograph. Currently, the methods for determining gas composition in 40 CFR 98.254(d) rely on gas chromatography. Advances in data analytics have made it easier for mass spectrometer analyzers to determine concentrations of individual compounds from a mixture of hydrocarbons without the need for pre-separation of the compounds using gas chromatography. Direct analysis using mass spectrometer analyzers greatly reduces the cycle time between sample analyses, allowing improved process control. As such, some refinery owner/operators use direct mass spectrometer analyzers to determine gas stream composition. The proposed inclusion of direct mass spectrometer analysis as an allowable gas composition method in 40 CFR 98.254(d) would allow these reporters to use the same analyzers used for process control or for compliance with continuous sampling required 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. Currently, these reporters have to conduct separate periodic sampling of these gas streams for analysis using gas chromatography to comply with GHGRP requirements in subpart Y. Thus, the proposed inclusion of mass spectrometer analyzers for determining gas composition will reduce the burden for these reporters. It is also expected to provide more accurate data due to the use of continuous analyzers rather than periodic sampling.

M. Subpart BB—Silicon Carbide Production

For the reasons described in section II.A.4 of this preamble, we are proposing revisions to the reporting requirements for subpart BB of part 98 (Silicon Carbide Production) to improve the quality of the data collected under the GHGRP.

The original 2009 GHG Reporting Rule for silicon carbide production required reporting CH_4 emissions by measuring petroleum coke consumption and applying a default CH_4 emission factor of 10.2 kilograms of CH_4 per metric ton of coke consumed (see 74 FR 56260). However, in 2013, we removed the requirement for silicon carbide production facilities to report CH_4 emissions from silicon carbide process units or furnaces and the CH_4 calculation methodology because we determined that the then-current CH_4 calculation methodologies in subpart BB overestimated the emissions of CH_4 from silicon carbide facilities. At the time we determined the following: the equations did not take into consideration the destruction of CH_4 emissions, the CH_4 emissions from these facilities were typically controlled, the CH_4 emissions from these facilities were minimal, and the requirement to report CH_4 emissions was not necessary to understand the emissions profile of the industry (see 78 FR 19802, April 2, 2013, and 78 FR 71904, November 29, 2013). The determination to not require reporting of CH_4 emissions was predicated on the conclusion that because CH_4 emissions are typically controlled, CH_4 emissions from these facilities are minimal. Although our understanding is still that CH_4 emissions are typically controlled, we are proposing to amend the rule in order to gather more information on CH_4 control practices at silicon carbide production facilities to better understand the extent of those control practices and their impact on CH_4 emissions. Specifically, we are interested in how the CH_4 emissions are controlled, the efficiency of the control technologies, and to what extent these technologies are operated throughout the year. As such, we are proposing adding new reporting requirement 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; (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. The proposed reporting requirements would be used to confirm the operation and efficiency of CH_4 abatement at silicon carbide facilities and would enable us to determine whether the EPA's 2013 determination that CH_4 emissions are typically controlled (and therefore minimal) remains accurate. Although silicon carbide facilities would continue to not be required to estimate CH_4 emissions from their processes for their GHGRP annual report, providing data on CH_4 abatement technology and usage would allow the EPA to assess the potential for unabated CH_4 emissions that may influence the industry's emission profile under the GHGRP. We also anticipate that we could use this kind of information to better understand methane emission control practices at silicon carbide facilities, to improve the EPA's knowledge of CH_4 emissions that may be useful for other CAA programs, or to support future climate change policies, non-regulatory initiatives, or regulations under the CAA. The proposed data could also be used to help estimate CH_4 emissions from silicon carbide facilities at the national level, and thereby inform and improve the U.S. GHG Inventory by allowing for more accurate estimates that account for CH_4 removal.

We are also proposing that 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 provide the name of the test method that was used during the performance test. We note that the collection of data elements related to GHG abatement and methane destruction are consistent with other subparts such as subparts E (Adipic Acid Production), I (Electronics Manufacturing), V (Nitric Acid Production), HH (Municipal Solid Waste Landfills), and FF (Underground Coal Mines) of part 98. For these subparts, reporters are typically provided an option to account for the destruction of methane in their estimated emissions (*e.g.,* fluorinated gases abated in electronics manufacturing processes or collection and destruction of methane at MSW facilities) and provide similar information on the type of abatement technology, hours of operation, and destruction or control efficiencies. This data is typically used for verification of emissions estimates and to confirm where process technologies or control measures result in minimal emissions. The collection of abatement data from silicon carbide facilities would be consistent with this practice. Finally, we are proposing that upon reporting this information once in an annual report, reporters would not be required to report this information again unless the information changed during another reporting year, in which case, the reporter would update the information in the submitted annual report. However, if it appeared that operational practices change at facilities such that CH_4 emissions are not consistently controlled from year to year or that unabated CH_4 emissions may be a more substantive contributor to industry emissions, then the EPA may consider whether it would be beneficial to reintroduce CH_4 calculation methodology and reporting requirements. We are proposing adding recordkeeping requirement 40 CFR 98.287(d) for facilities to maintain a copy of the reported data.

Based on review of available permits, we anticipate that reporters could obtain the proposed data elements from data that is collected and readily available to facilities as part of their standard operation. For example, as part of normal operations, we assume facilities would keep records of any time that the CH_4 abatement technology was not in use; therefore, the facility could then calculate the percent of total operating hours that the abatement technology was not in use. We are soliciting comment on whether this assumption is correct. We are also proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

We are also seeking comment on alternative methods for determining destruction efficiency (*i.e.,* methods other than using either the manufacturer's specified destruction efficiency or the destruction efficiency determined via a performance test). For example, we are considering whether it would be more reasonable to allow for the ''lesser of manufacturer's specified destruction efficiency and 0.99,'' as is required in subpart HH.

N. Subpart DD—Electrical Transmission and Distribution Equipment Use

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

For the reasons discussed in section II.A.3 of this preamble, we are proposing several revisions to subpart DD of part 98 (Electrical Transmission and Distribution Equipment Use) to improve the quality of the data collected from this subpart. These include adding F–GHGs other than SF_6 and PFCs to the monitoring, calculation, and reporting requirements of subpart DD (at 40 CFR 98.302, 98.303, 98.304, 98.305, and 98.306), clarifying the definition in 40 CFR 98.308 for ''facility,'' adding definitions for ''energized,'' ''insulating gas,'' ''new equipment,'' and ''retired equipment,'' and specifying procedures in 40 CFR 98.303(b) for establishing user-measured nameplate capacity values for new and retiring equipment.

Currently, this subpart includes all electric transmission and distribution equipment and servicing inventory insulated with or containing SF_6 or PFCs used within an electric power system. We are proposing to revise the existing calculation, monitoring, and reporting requirements of subpart DD to require reporting of additional F–GHGs as defined under 40 CFR 98.6. At the time of the 2010 Final Rule for Additional Fluorinated GHGs, SF_6 was the most commonly used insulating gas in the electrical power industry, and PFCs were occasionally used as dielectrics and heat transfer fluids in power transformers. During the implementation of the reporting program, electrical power systems equipment manufacturers and F–GHG suppliers have introduced alternative technologies and replacements for SF_6 with lower GWPs, including fluorinated gas mixtures, such as fluoronitriles or fluoroketones mixed with carrier gases (*e.g.,* CO_2 and O_2), as a replacement for dielectric insulation gases. The GWPs of these gases are generally much lower than the GWP of SF_6; the GWPs of fluoronitrile mixtures are typically estimated to fall between 300 and 500, whereas the GWPs of fluoroketone mixtures are usually estimated to be less than 1. The EPA is aware that some electric power systems are currently using or considering use of these alternative gas mixtures; Therefore, we are proposing revisions to the reporting requirements in order to capture emissions from equipment using these alternative gases that are not currently accounted for. While the use of alternative insulation gases will generally result in lower GHG emissions, we would expect that that increased usage of these alternative technologies, particularly fluoronitrile mixtures, could still significantly contribute to the total GHG emissions from this sector if used in large quantities. The proposed reporting of these additional F–GHGs would improve the accuracy and completeness of the emissions reported under subpart DD and enhance the overall quality of the data collected under the GHGRP.

To implement these revisions, we are proposing at 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).'' As discussed in section III.N.2 of this preamble, the proposed changes would also apply to the threshold in 40 CFR 98.301. Under the proposed rule, both electric power systems and electric generating units with insulated equipment would also consider any additional F–GHGs, including those in F–GHG mixtures, used at the facility in the nameplate capacity used for estimating the threshold. At this time, we are unaware of any facilities that currently use the alternative gas mixtures exclusively or in large quantities that would render them newly subject to the subpart; therefore, we expect the minimal burden from the proposed requirements would fall on existing reporters, who would only be required to account for the additional F–GHGs in their gas-insulated equipment (GIE) and inventory.

The proposed revisions to subpart DD include minor revisions to equation DD–1 (which would be redesignated as equation DD–3 at 40 CFR 98.303(a) under this proposed rule) to incorporate the estimate of emissions from all F–GHGs within the existing calculation methodology, including F–GHG mixtures. Equation DD–3 would 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 would require applying the weight fraction of each F–GHG to determine the user emissions by gas. It is our understanding that facilities receive gas in equipment pre-mixed and do not mix the gas themselves; therefore, the proposed revisions assume that facilities will track the mixtures received, and rely on supplier data to obtain the weight fraction of each F–GHG within equipment containing a gas mixture. Facilities would need to track mixtures with unique weight fractions of individual F–GHGs separately. However, we are seeking comment on whether the weight fraction of individual F–GHGs is readily available from supplier data. We are also seeking comment on whether there are facilities that mix gas in equipment on site, or that expect to mix gas in equipment at the facility in the future, and whether we should account for this mixing in the current equation. Since we assumed that gases are typically received pre-mixed, the proposed changes include reporting of an ID number or descriptor for each insulating gas and the name and weight percent of each fluorinated gas of each insulating gas reported. To simplify references to F–GHGs and F–GHG mixtures throughout the subpart (especially in equation DD–3), we are proposing to introduce the term ‘‘insulating gas’’ and to define it as follows: ‘‘*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.’’ The proposed changes also include updating the monitoring and quality assurance requirements at 40 CFR 98.304(b) to account for emissions from additional F–GHGs, and harmonizing revisions to the term ‘‘facility’’ in the definitions section at 40 CFR 98.308, and the requirements at 40 CFR 98.302, 40 CFR 98.305, and 40 CFR 98.306 such that reporters would account for the mass of each F–GHG for each electric power system. The proposed changes would not significantly revise the existing calculation, monitoring, or reporting requirements; therefore, we expect only a minimal increase in burden due to the collection of data for any equipment containing F–GHGs that are not SF_6 or PFCs. We are proposing related confidentiality determinations for the revised data elements that incorporate additional F–GHGs, as discussed in section VI of this preamble. We are proposing one additional change to remove an outdated monitoring provision at 40 CFR 98.304(a), which reserves a prior requirement for use of BAMM that applied solely for RY2011.

For the reasons described in section II.A.5 of this preamble, we are also proposing to add new definitions to clarify the existing provisions of the rule. The mass balance methodology in 40 CFR 98.303 (used for calculating facility emissions) uses the terms ‘‘new’’ and ‘‘retired’’ to describe equipment added to or removed from active use, and reporters are required to report nameplate capacity and the number of F–GHG containing pieces of any new and retired equipment. We have previously received questions from reporters regarding what equipment should be included as new or retired equipment each year, and we developed interpretations of these terms for our list of Frequently Asked Questions.[112] We are proposing to adopt the previous interpretations into the rule's requirements in order to help ensure that reporters correctly estimate emissions, which would improve the quality of the data collected. The proposed revisions would also reduce time spent searching the list of Frequently Asked Questions or responding to questions through the GHGRP Help Desk.

First, we are proposing a definition at 40 CFR 98.308 of ‘‘energized’’ to more clearly designate what equipment is considered to be installed and functioning as opposed to being in storage. The proposed definition clarifies that energized equipment includes gas-insulated equipment (including hermetically-sealed pressure switchgear) that is connected through busbars or cables to an electrical power system or that is fully-charged, ready for service, and being prepared for connection to the electrical power system, and does not include spare GIE (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. Consistent with our previous interpretation, we are proposing to add a definition for ‘‘new equipment’’ to mean any GIE, 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. Similarly, we are proposing a definition for ‘‘retired equipment’’ to mean any GIE, 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. Finally, we are clarifying that (1) new equipment may also include equipment 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), and (2) retired equipment may also include equipment 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 of ‘‘energized,’’ ‘‘new equipment,’’ and ‘‘retired equipment’’ are intended to clarify how these terms should be interpreted for purposes of the equation used to estimate emissions for annual reporting (*i.e.,* the current equation DD–1, which we are proposing to redesignate as equation DD–3). This equation uses a mass-balance approach that assesses annual net gas consumption (based on the decrease in gas inventory and gas acquisitions and disbursements) and accounts for gas used or freed up, respectively, by equipment installations and

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[112] U.S. EPA. ‘‘*Q852. What equipment should be included as new or retired equipment each year for Subpart DD?*’’ April 6, 2020. *https://ccdsupport.com/confluence/pages/viewpage.action?pageId=721715270.*

retirements.[113] The nameplate capacity of new equipment is subtracted from the total, reflecting the fact that some of the insulating gas consumed is used to fill the new equipment, while the nameplate capacity of retiring equipment is added to the total, reflecting the fact that the gas formerly used to fill the retiring equipment, unless emitted, would either be added to the gas inventory or disbursed (*e.g.,* to an SF_6 recycling company). Implicit in this approach are the assumptions that ''new'' equipment is filled with insulating gas during the same year that it is considered ''new,'' and that ''retired'' equipment is emptied of insulating gas during the same year that it is considered ''retired.'' [114] We request comment on whether new equipment is typically filled with gas during the same year that it is ''energized'' under the proposed definition of ''energize,'' and on whether retiring equipment is typically emptied of gas during the same year that it ceases to be ''energized'' under the proposed definition. If gas is added to or removed from ''new'' and/or ''retired'' equipment in a year different from the year that the equipment is energized or ceases to be energized, respectively, it may be clearer to directly tie the terms ''new'' and ''retired'' to the filling and emptying of the equipment (for closed-pressure equipment).

In 40 CFR 98.303(b) we are proposing to require 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. This option would be available only for closed-pressure equipment with a voltage capacity greater than 38 kV, not for hermetically sealed pressure equipment or smaller closed-pressure equipment. The 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 also intended to be similar to and compatible with the procedures for measuring nameplate capacity adopted by the California Air Resources Board (CARB) in its Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (effective January 1, 2022).[115]

As discussed above, the nameplate capacities of new and retiring electrical equipment are used in the current equation DD–1 of subpart DD (which would be redesignated as equation DD–3 under this proposed rule), which calculates annual GHG emissions from the equipment. In the equation, nameplate capacity is defined as referring to ''the full and proper charge of equipment rather than to the actual charge, which may reflect leakage.'' With each piece of electrical equipment, electrical equipment manufacturers typically provide a rated nameplate capacity in pounds of SF_6 (or other insulating gas) on a nameplate affixed to the equipment and/or in the product specifications. When the EPA promulgated subpart DD, we expected that users of electrical equipment would be able to use these rated nameplate capacities in their emissions calculations without introducing any errors. Experience has shown, however, that even when users of electrical equipment follow industry-accepted equipment filling and gas measuring methods, the mass of insulating gas contained in the equipment when it is filled to the manufacturer-specified density can sometimes differ from that specified on the nameplate. That is, the actual nameplate capacity of the equipment (the full and proper charge) can differ from the rated nameplate capacity of the equipment.[116]

Differences between the actual and rated nameplate capacities may result in either under- or over-estimates of emissions in the short run, depending on: (1) whether the actual nameplate capacity is greater than the rated nameplate capacity or vice versa; and (2) whether the equipment is being commissioned or retired. For example, if the actual nameplate capacity of new equipment is larger than the rated nameplate capacity of that equipment, emissions will be overestimated, because some of the gas that was actually used to fill the new equipment will be assumed to have been emitted. On the other hand, if the actual nameplate capacity of retiring equipment is larger than the rated nameplate capacity of the equipment, emissions will be underestimated (and may even be calculated as negative), because the quantity of gas recovered or emitted from the retiring equipment will be larger than is accounted for by the equation. (More scenarios are described in the document *Technical Support for Proposed Revisions to Subpart DD (2021)* included in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.)

As the above example shows, these underestimates and overestimates from a piece of equipment would cancel out over the lifetime of the equipment. To some extent, they may also cancel out in any given year because rated nameplate capacities can be either larger or smaller than the actual nameplate capacities, and most electrical equipment users are likely to both install and retire several pieces of equipment during the year. However, if a large piece of electrical equipment (or several smaller pieces of electrical equipment) is installed or retired in a given year, an error in the rated nameplate capacity of that equipment could potentially have a significant impact on the calculated emissions from the electrical equipment user in that year.

For this reason, when electrical equipment users have asked the EPA via the Helpdesk whether they may use a nameplate capacity value different from the rated nameplate capacity value in their calculations and reporting under subpart DD, we have responded [117] that

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[113] This particularly applies to closed-pressure equipment. Closed-pressure equipment is typically delivered to the facility without a full and proper charge of insulating gas and therefore must be filled to the full and proper charge before it is energized. Similarly, closed-pressure equipment is typically emptied of insulating gas before it is sent off-site for recycling or disposal. Hermetically sealed-pressure equipment, on the other hand, is generally expected to be fully charged upon delivery unless it has leaked en route. Hermetically sealed-pressure equipment is also often sent off-site (*e.g.,* returned to the equipment manufacturer) with its charge intact unless it has leaked over its lifetime.

[114] Note that this logic does not necessarily apply to equipment that is ''new'' or ''retired'' because it is transferred to or from another owner while it remains energized. In this case, we are assuming that insulating gas is not generally added to or removed from equipment upon transfer, and that both the transferring and receiving facilities would presume that the equipment is transferring with its full and proper charge, meaning that the transfer of such equipment would not affect the emissions calculated under the mass-balance equation. We request comment on whether this assumption is correct.

[115] State of California Air Resources Board, ''Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear.'' Available at *https://ww2.arb.ca.gov/rulemaking/2020/sf6?utm_medium=email&utm_source=govdelivery.*

[116] Electrical equipment manufacturers indicate that this is because the rated nameplate capacity was historically only intended to indicate the approximate mass of gas required to fill equipment. The full and proper charge for a given model of equipment can vary from year to year and even from one piece of equipment to the next due to minor design changes and manufacturing variability. To ensure that the equipment functions correctly, manufacturers provide precise instructions for filling to the proper density. (The Electric Transmission & Distribution SF_6 Coalition (administered by NEMA), *SF_6 Reporting Challenges,* undated. Accessed at *https://www.nema.org/docs/default-source/products-document-library/sf6-reportingchallenges.pdf* on June 3, 2021.)

[117] See documents ''HELPDESK–64899'' and ''HELPDESK–30364'', available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

they may use the nameplate capacity value that corresponds to the full and proper charge of the equipment, which is determined based on density (*e.g.,* the temperature-corrected pressure of the equipment) per the manufacturer's filling instructions. We have also noted that subpart DD does not currently specify a method for calculating nameplate capacity values, but for the mass-balance approach to yield correct results, the nameplate capacity value should reflect any shipping charge contained in the equipment upon delivery, and the same nameplate capacity value should be used throughout the life of the equipment. Finally, we have noted that paragraph 98.3(g)(2) requires equipment users to keep records of the method used to calculate the nameplate capacity value.

The process that we are proposing in this action would elaborate on and adopt this guidance into the rule's requirements. It is designed to avoid a number of potential errors by equipment users that can result in inaccuracies in the nameplate capacities that they measure. Such errors can occur when:

- Equipment is deliberately overfilled or underfilled;
- Shipping charges are accounted for incorrectly or not at all;
- Inaccurate weigh scales, flowmeters, pressure gauges, or thermometers are used to fill equipment;
- The temperature of the insulating gas is not measured accurately when the equipment is filled or emptied (*e.g.,* the temperature of the gas is incorrectly equated to the ambient temperature);
- The insulating gas in equipment (especially retiring equipment) is not completely recovered (or the gas remaining in the equipment is not accounted for);
- Previous leakage from equipment (especially retiring equipment) is not accounted for; or
- Insulating gas in hoses and gas carts is not accounted for.

To avoid these potential errors, the EPA is proposing certain requirements at 40 CFR 98.303(b) for when electrical equipment users measure the nameplate capacity of new equipment that they install. These proposed requirements for new equipment would help ensure that electrical equipment users:

- Correctly account for the mass of insulating gas contained in equipment upon delivery from the manufacturer (*i.e.,* the holding charge);
- Use flowmeters or weigh scales that meet certain accuracy and precision requirements to measure the mass of insulating gas added to 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, allowing appropriate time for temperature equilibration; and
- Ensure that insulating gas remaining in hoses and gas carts is correctly accounted for.

The EPA is also proposing certain requirements at 40 CFR 98.303(b) for when electrical equipment users measure the nameplate capacity of retiring equipment. These proposed requirements for retiring would help ensure that electrical equipment users:

- 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 recovered from the equipment;
- Use pressure-temperature charts and pressure gauges and thermometers that meet certain accuracy and precision requirements 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.

We are proposing at 40 CFR 98.303(b)(6) that instead of measuring the nameplate capacity of electrical equipment when it is retired, users may measure the nameplate capacity of electrical equipment earlier during maintenance activities that require opening the gas compartment. In this case, the equipment user would 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 would be recorded but would not be used in equation DD–3 until that equipment was actually retired.

As previously mentioned, only closed-pressure equipment with a voltage capacity greater than 38 kV would be eligible for nameplate capacity measurement and correction. This is because the quantities of insulating gas that are typically inside hermetically sealed-pressure equipment and in closed pressure equipment with smaller voltage capacities are individually and collectively less significant than those in closed-pressure equipment with voltage capacities at or above 38 kV. Consequently, any errors in the rated nameplate capacities of smaller equipment are not likely to have a significant impact on the calculated emissions of equipment users, and efforts to correct the nameplate capacity values of smaller equipment do not appear to be justified by the improvement in accuracy that would result. CARB has established eligibility criteria similar to those we are proposing based on their finding that the criteria would cover ''approximately 23 percent of California's GIE [gas insulated equipment] and approximately 80 percent of the SF_6 used in the State.'' [118] In addition, users rarely add or remove gas to or from hermetically sealed-pressure equipment, by design. We request comment on the proposed eligibility criteria.

We are proposing a scheme in 40 CFR 98.303(b) that would require all eligible new and retiring equipment to be treated consistently with respect to the measurement and adoption of nameplate capacities. To avoid biases that could result from measuring and adopting nameplate capacities for some pieces of eligible new or retiring equipment but not others, electrical equipment users electing to measure the nameplate capacities of any new or retiring equipment would 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 would 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 differed from the rated nameplate capacity by two percent or more, the electrical equipment user would 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 differed from the rated nameplate capacity by less than two percent, the electrical equipment user would 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 would be required to adopt the user-measured nameplate capacities for all new and retiring equipment

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[118] State of California Air Resources Board, ''Notice of Public Availability of Modified Text: Proposed Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear,'' May 5, 2021, pp. 17–18.

whose user-measured nameplate capacity differed from the rated nameplate capacity by less than two percent. As is the case for the proposed requirement to consistently measure or not measure the nameplate capacities of all new and retiring equipment, the proposed requirement to consistently adopt or not adopt the user-measured nameplate capacities where they differ from the rated nameplate capacity by less than two percent is intended to avoid bias that could result from adopting only a subset of the user-measured nameplate capacities that fall into this category.

We are proposing the two-percent tolerance for differences between the user-measured and rated nameplate capacities because, given the precisions and accuracies that we are proposing for the measuring devices (scales, gauges, etc.) used to calculate nameplate capacities (as discussed further in this section), differences of one percent or less are not expected to be mathematically meaningful. We request comment on the value of two percent and on whether the percentage tolerance should be supplemented by an absolute tolerance, such as 100 pounds of SF_6 (equivalent to 1,034 $mtCO_2e$). In the latter case, differences equal to or greater than the lesser of two percent or 100 pounds would trigger the requirement to use the user-measured nameplate capacity. The drawback of using a separate absolute tolerance is that this tolerance may not be mathematically meaningful if the full and proper charge of the equipment exceeded 10,000 pounds.

Our proposal to allow electrical equipment users to adopt the user-measured nameplate capacity even when the difference between that capacity and the rated capacity is less than two percent is based on our desire to maintain as much consistency as possible between GHGRP requirements and the proposed requirements of CARB. Our understanding is that CARB is proposing [119] to require electrical equipment users in California to measure the nameplate capacity of all newly installed closed pressure equipment with a voltage capacity greater than 38 kV and to adopt the measured value irrespective of the magnitude of the difference between the measured value and the manufacturer-supplied value.

When electrical equipment is retired, the quantity of the gas remaining in the equipment may reflect leakage that has occurred since the last time the equipment was serviced or re-filled. In this case, we are proposing at 40 CFR 98.303(b)(5) to allow equipment users to account for the leakage using one of two approaches. In both approaches, equipment users would: (1) measure the temperature-compensated pressure of the equipment before they removed the insulating gas from that equipment; and (2) 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 was different from the temperature-compensated pressure corresponding to the full and proper charge of the equipment, the equipment user could either (a) add or remove insulating gas to or from the equipment until the equipment reached 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,[120] and weigh the recovered gas (charge adjustment approach), or (b) if the measured temperature-compensated pressure was at least 90 percent of the temperature-compensated design operating pressure, 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). In the mathematical adjustment approach, proposed as equation DD–4, the equipment user would calculate the mass of the full and proper charge by scaling up the mass recovered by the ratio of pressures (in absolute terms) corresponding to the full and proper charge and the actual charge, respectively, accounting for any insulating gas remaining in the equipment (if the final pressure of the equipment exceeded 0.068 psia).[121] We are proposing to limit the mathematical adjustment approach to situations where the measured temperature-compensated pressure is equal to or greater than 90 percent of the design operating pressure to ensure that nameplate capacity measurements and calculations remain precise. If smaller fractions of the full charge are scaled up to calculate the nameplate capacity, the uncertainty of the calculation begins to approach (and ultimately exceed) two percent given the precision and accuracy requirements we are proposing for pressure gauges and other measurement devices. We request comment on the expected accuracy of the mathematical adjustment approach, and whether it should be enhanced to account for non-linearities in the relationship between pressure and density. Our analysis of this issue, discussed in the Technical Support Document, indicates that such non-linearities can lead to systematic errors in the results of the mathematical adjustment approach under some circumstances. One way of addressing such non-linearities would be to include a compressibility factor (often termed a ''Z'' factor) in the calculation, as we have done for gas measurements for other subparts (see, *e.g.,* equation I–25 of subpart I (Electronics Manufacturing) and equation L–33 of subpart L (Fluorinated Gas Production) of part 98). A version of equation DD–4 including compressibility factors is included in the Technical Support Document.

The mathematical adjustment approach would accommodate situations where it may not be possible to fully recover the insulating gas from the equipment, *e.g.,* where the equipment has leaks through which air would be drawn into the equipment and subsequently into the recovery equipment or gas cart if the equipment were drawn into a deep vacuum. However, as discussed further in the Subpart DD TSD, an inability to pull the equipment into a vacuum may lead to inaccurate nameplate capacity measurements unless the accuracy and precision requirements for pressure gauges are tightened beyond those in the proposed rule. We request comment on this issue and on alternative methods for addressing nameplate capacity measurements for equipment with large leaks. For example, CARB has adopted an exception to its nameplate capacity measurement requirements for equipment with ''compromised integrity.'' The mathematical adjustment approach would also avoid some of the disadvantages of the charge adjustment approach, which, compared to the mathematical adjustment approach, would be more time-consuming and risks emitting more insulating gas and

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[119] Attachment A: Modifications to the Proposed Regulation Order, California Air Resources Board, available at *https://ww3.arb.ca.gov/board/15day/sf6/15dayatta.pdf.*

[120] 3.5 Torr is a common ''blank-off pressure'' to which gas carts are designed to recover insulating gas from electrical equipment. At 3.5 Torr, the EPA estimates that 0.1 percent of the full and proper charge of insulating gas would remain in the equipment, assuming that a full and proper charge has a pressure of 5 atmospheres (3800 Torr). We are therefore proposing to treat quantities of gas remaining at pressures of 3.5 Torr and below as negligible in nameplate capacity calculations.

[121] Equipment users could also use a hybrid approach wherein they would top up the equipment but account mathematically for any gas remaining in equipment at a pressure above 0.068 psia.

contaminating the insulating gas used to top up the equipment with impurities in the gas that remains in the equipment.

To ensure that the mass-balance method is based on consistent nameplate capacity values throughout the life of the equipment, we are proposing at 40 CFR 98.303(b)(9) that electrical equipment users would be 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).

Currently, subpart DD requires that scales used to measure cylinders of gas be accurate and precise to within 2 pounds of true weight and be periodically recalibrated per the manufacturer's specifications. Subpart DD does not include accuracy or precision requirements for other measuring devices, such as flow meters, pressure gauges, or thermometers. To help ensure that electrical equipment users obtain accurate measurements of their equipment's nameplate capacities, we are therefore proposing at 40 CR 98.303(b)(10) that electrical equipment users use measurement devices that meet the following accuracy and precision requirements when they measure the nameplate capacities of new and retiring equipment.

(1) 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.

(2) 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.

(3) Temperature gauges must be certified by the manufacturer to be accurate and precise to within ±1.0 °F; and

(4) Scales must be certified by the manufacturer to be accurate and precise to within one percent of the true weight.

These requirements are the same as those proposed by CARB in its May 5, 2021 and June 17, 2021 documents,[122] except we are clarifying that the measurement devices must be precise as well as accurate. The measurement devices listed here would be subject to the general GHGRP calibration requirements at 40 CFR 98.3(i).

Even if electrical equipment users use an accurate thermometer, they may under- or overestimate the temperature of the gas being filled into the equipment or recovered from it, for example if they assume that the gas is at the same temperature as the area surrounding the equipment. This is because gas that is filled into equipment from a container may be cooler or warmer than the ambient temperature depending on the method used to transfer the gas. Where the insulating gas is pulled from the container in the liquid phase, an evaporator is generally used between the container and the equipment to ensure that only gas is transferred into the electrical equipment. A representative of a gas cart manufacturer indicated that the gas transferred using this method is often slightly warmer than the ambient temperature. In this case, the density of the gas will be lower than the density calculated using the ambient temperature. Where the insulating gas is pulled from the container in the gas phase, the container (and the gas inside) tends to cool as the gas boils off from a reservoir of liquid insulating gas in the container. Heating blankets are often used to warm the container and gas in this case, but they may not compensate for the temperature loss associated with the phase change. In this case, the gas will be cooler than the ambient temperature, and its density will be higher than the density calculated using the ambient temperature. To at least partly address these issues, we are proposing to require that equipment users measure the temperature of the electrical equipment rather than relying on the ambient temperature when making nameplate capacity measurements. However, even measurements on the surface of the electrical equipment may not reflect the temperatures inside, at least not right away. To ensure that the temperature of the gas is not under- or overestimated, we are considering requiring a minimum temperature equilibration time following the gas filling procedure. We request comment on this option, including on what appropriate waiting times would be for temperature equilibration for equipment of different sizes and on whether manufacturer filling directions adequately address temperature measurement issues. Temperature equilibration times that we are considering range from 30 minutes for relatively small equipment to 8 to 24 hours for large equipment.

We also request comment on whether it would be sufficient to require that any gas inside hoses is ''accounted for'' both before and after equipment filling or emptying processes, or whether we should specify a more detailed procedure for evacuating hoses before and after equipment filling and emptying. A representative of a gas cart manufacturer who commonly provides training on use of its gas carts described the following procedure to the EPA: Any gas in the hoses should be pulled back into the gas cart/cylinders before the filling or emptying process begins, and the baseline measurements on scales and/or flow meters should be taken at that point. Then the equipment should be filled or emptied, the hoses should be isolated from the equipment, and any remaining gas in the hoses should be pulled back into the gas cart/cylinders. At that point the final measurements on scales and/or flow meters should be taken. We request comment on whether we should require use of this procedure or whether there may be other acceptable procedures for ensuring that any gas in hoses is accounted for in nameplate capacity measurements.

We are proposing at 40 CFR 98.307(b) to require 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. In addition, we are proposing at 40 CFR 98.306(o) and (p) to require 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. Collecting this information would help enable us to ascertain the average magnitude of nameplate capacity adjustments at both the facility and U.S. level, providing insight into the extent to which manufacturer-assigned nameplate capacities may err and alerting us to situations where adjustments are unusually large, which may indicate

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[122] State of California Air Resources Board, ''Notice of Public Availability of Modified Text: Proposed Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear,'' May 5, 2021, and State of California Air Resources Board, ''Notice of Public Availability of Modified Text: Proposed Amendments to the Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear,'' June 17, 2021. Available at *https://ww2.arb.ca.gov/rulemaking/2020/sf6?utm_medium=email&utm_source=govdelivery.*

that equipment users are not following the procedures specified in the rule to ensure that they measure nameplate capacity values accurately.

2. Proposed Revisions To Streamline and Improve Implementation for Subpart DD

In alignment with our proposed revisions to include additional F–GHGs in the source category, and for the reasons described in section II.B.1 of this preamble, we are proposing to revise the applicability threshold of subpart DD at 40 CFR 98.301. Subpart DD currently requires reporting from facilities with a total nameplate capacity of SF_6 and PFC-containing equipment located within the facility or under common ownership or control exceeding 17,820 pounds. The EPA established the nameplate capacity threshold [123] of 17,820 pounds in the 2010 Final Rule for Additional Sources of Fluorinated GHGs(75 FR 74774) as an ''equivalent threshold'' that approximated the 25,000 metric tons of CO_2 threshold for emissions. Emissions of SF_6 and PFC from the source category include emissions from equipment leaks and venting from gas-insulated substations and switch gear. The insulating gas can also be released during equipment manufacturing, installation, normal operation and maintenance, and disposal. We initially chose a nameplate capacity-based threshold because nameplate capacity is strongly correlated with SF_6 emissions, and a capacity-based threshold allows potential sources to determine whether they are above or below the threshold more quickly and with less effort than through estimating emissions.[124] The threshold of 17,820 pounds was estimated using the GWP of SF_6 that was applicable at the time and historical leakage data reported by industry owners and operators who are partners in EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

To help ensure that the GHGRP data collected better reflects the emission rates and insulating gases that prevail in the current electric power system industry, we are proposing to replace the existing nameplate capacity threshold with an emissions threshold of 25,000 metric tons CO_2e per year of F–GHGs. To calculate their F–GHG emissions for comparison with the threshold, electrical equipment users would use one of two new equations in subpart DD at 40 CFR 98.301, proposed equations DD–1 and DD–2. The proposed 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. The equations would therefore account for additional fluorinated gases (including GHG mixtures) now being marketed to the industry as well as lower reported emission rates within the industry.[125] The current nameplate-capacity based threshold was based on the historical emission rate, which was estimated at approximately 13 percent, and the GWP for SF_6. For small facilities (total nameplate capacity between 17,000 and 50,000 lbs), the largest emission rate reported since 2013 (based on beginning of year capacity) was 10.3 percent.[126] Additionally, some facilities within this industry sector may have begun to use lower GWP F–GHGs, which is not reflected when using only nameplate capacity of the equipment to determine applicability. Therefore, the current nameplate capacity threshold may require facilities with annual subpart DD emissions below 25,000 $mtCO_2e$ per year to report. Revising the reporting threshold to account for lower emission rates and the use of F–GHGs with lower GWPs would reduce burden for those electric power systems and facilities that have decreased their reliance on SF_6-insulated equipment and would maintain a threshold equivalent to the 25,000 $mtCO_2e$ threshold.

As discussed in section III.N.1 of this preamble, we are proposing to revise the existing calculation, monitoring, and reporting requirements of subpart DD to require reporting of additional F–GHGs beyond SF_6 and PFCs. Therefore, the proposed new equations DD–1 and DD–2 that we are proposing for the applicability threshold would require potential reporters to account for the total nameplate capacity of all F–GHG containing equipment (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 have determined that the proposed threshold methodology is more appropriate because it represents the actual fluorinated gases used by a reporter, accounts for gas mixtures, and updates the contemporaneous emission rate performance for the industry.[127] Finally, we are proposing harmonizing changes in multiple subsections to renumber existing equation DD–1 and maintain cross-references to the equation.

The proposed revisions would also streamline the reporting requirements to focus Agency resources on the substantial emission sources within the sector and would exclude new electric power systems and other new facilities from subpart DD when their emissions of insulating gas were estimated to be below 25,000 $mtCO_2e$ per year. The proposed changes would revise the existing threshold in 40 CFR 98.301 and Table A–3 to subpart A (General Provisions). Reporters would continue to determine the applicability of subpart DD under 40 CFR 98.2(a)(1), which applies to source categories listed in Table A–3, such that only total estimated emissions from F–GHGs would be accounted for in determining whether the applicability threshold is met. Therefore, facilities would continue to determine the applicability of subpart DD without consideration of the combined emissions from stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and other applicable source categories towards the threshold.

Due to the definition of ''facility'' for electric power systems that is different from the definition of ''facility'' (in subpart A of part 98) that covers facilities in other subparts, electric power systems always report to the GHGRP as unique facilities (*i.e.,* emissions from other sources covered by the GHGRP that may have overlap in location with a subpart DD facility are reported under a different e-GGRT identifier due to the different definition of ''facility''). Thus, placement of subpart DD in Table A–3 or Table A–4 of subpart A has no effect on the emissions considered when determining applicability for electric power systems if an equivalent threshold is used.

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[123] The current threshold is based on the total nameplate capacity of SF_6 or PFC containing equipment located within the facility and SF_6 or PFC containing equipment that is not located within the facility but is under common ownership or control.

[124] See U.S. EPA. *Subpart DD Technical Support Document—Use of Electric Transmission and Distribution Equipment,* November 2010. Available at *https://www.epa.gov/sites/production/files/2015-03/documents/subpartdd-tsd-electricpowerequip.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[125] *Id.* The leak rate was originally based on 1999 weighted leak rates from 42 entities reporting to the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

[126] Calculated based on beginning of year nameplate capacity and total reported emissions to subpart DD of 40 CFR part 98, Use of Electric Transmission and Distribution Equipment, Envirofacts, downloaded from *https://www.epa.gov/enviro/greenhouse-gas-customized-search* on July 8, 2020.

[127] For more information see, *Technical Support for Proposed Revisions to Subpart DD (2021),* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

However, for other facilities that use electrical equipment, it is possible to add emissions under subpart DD to those from other subparts as they use the standard definition of ''facility'' in Subpart A. We are currently proposing to maintain subpart DD in Table A–3 of subpart A. By keeping subpart DD in Table A–3, we expect to continue to capture the majority of annual emissions from the use of electrical transmission and distribution equipment (approximately 65 percent in 2019; down from a high of 73 percent due to some facilities becoming eligible to exit the program[128]) while not significantly increasing burden. Moving subpart DD to Table A–4 of subpart A would likely have a significant impact on the number of reporters subject to subpart DD but is unlikely to result in a significant increase to the proportion of emissions covered by the GHGRP, because moving subpart DD to Table A–4 would only affect facilities that are not electric power systems. Facilities that are not electric power systems have historically reported emissions significantly below 25,000 mtCO_2e even when the total nameplate capacity at the facility was over the current threshold of 17,820 lbs.[129] One option that we are considering is to move use of electrical equipment to Table A–4 of subpart A, which would require facilities that used electrical equipment but that were not electric power systems to determine applicability according to 40 CFR 98.2(a)(2). Under this option, facilities that used electrical equipment but that were not electric power systems would be required to add their total estimated F–GHG emissions from electrical equipment to their combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all other applicable source categories that are listed in Table A–3 and Table A–4 to determine whether the facility emits 25,000 mtCO_2e or more per year in combined emissions and whether they were required to report under part 98. In other words, if the result of this calculation exceeded 25,000 mtCO_2e, they would be required to report their emissions from electrical equipment even if the F–GHG emissions from such equipment, by themselves, were below 25,000 mtCO_2e. We are considering requiring more comprehensive reporting of emissions from users of electrical equipment other than electric power systems because comparisons between the consumption of SF_6 reported to the GHGRP by SF_6 suppliers have generally exceeded the consumption reported by (or estimated by the EPA for) SF_6 users. It is possible that SF_6 consumption by users of electrical equipment with nameplate capacities under the current threshold (and therefore with SF_6 emissions that are likely to fall under the 25,000 mtCO_2e threshold) could account for some of this gap, and therefore it is possible that reporting by these facilities would at least partially explain the gap. However, we recognize that if we move subpart DD to Table A–4, numerous facilities that are subject to this part because of emissions from another source category would potentially be newly required to report under subpart DD with only a few pieces of gas-insulated equipment. One option for addressing this concern would be not to require reporting when emissions from the facility's electrical equipment, as calculated using equation DD–2, fell below a threshold, such as 1,000 mtCO_2e. We request comment on these options.

O. Subpart FF—Underground Coal Mines

The EPA is proposing two technical corrections to subpart FF of part 98 (Underground Coal Mines), for the reasons described in section II.A.5 of this preamble. First, we are proposing to correct the term ''MCF_i'' in equation FF–3 of subpart FF to revise the term ''1-$(fH_2O)_1$'' to ''1-$(fH_2O)_i$.'' The proposed change would correct an error inadvertently introduced in the November 29, 2013 final rule (78 FR 71967). Second, we are proposing a revision to 40 CFR 98.326(t). Facilities are required to report the Mine Safety and Health Administration (MSHA) identification number to the EPA. The technical correction would add the word ''number'' after the word ''identification'' to clarify the reporting requirement.

P. Subpart GG—Zinc Production

We are proposing one revision to subpart GG of part 98 (Zinc Production) that would improve the quality of the data collection under the GHGRP. For the reasons described in section II.A.4 of this preamble, we are proposing to add a reporting requirement at 40 CFR 98.336(a)(6) and (b)(6) for the total amount of EAF dust annually consumed by all Waelz kilns at zinc production facilities. EAF dust and other scrap materials are primary inputs at certain zinc production and recycling facilities from which zinc is recovered. The EPA is proposing to collect this data in order to improve verification of reported data under the GHGRP. This data would also improve emissions estimates developed as part of the U.S. GHG Inventory. Collection of this data would be useful for verification of data reported through the GHGRP by assisting with data validation. The amount of EAF dust consumed by facilities strongly correlates with process CO_2 emissions. Therefore, the total amount of EAF dust consumed by all Waelz kilns could be used for comparison to emissions estimates and would be useful for verifying consistency in emissions over time. Additionally, the U.S. GHG Inventory uses Tier 1 methods from the 2006 IPCC Guidelines to estimate emissions from zinc produced. For primary zinc production, the inventory uses a Waelz kiln emission factor based on zinc production for non-EAF dust consuming facilities, and a Waelz kiln emission factor based on EAF dust consumption for EAF-dust consuming facilities. Currently, the EPA is only able to obtain EAF dust consumed for a small number of facilities using Waelz kilns, which increases the uncertainty of these emission factors. Further, for Waelz kiln-based production, the IPCC recommends the use of emission factors based on EAF dust consumption, since the amount of carbonaceous materials (*e.g.,* coal or coke) used (which drives process CO_2 emissions) is more directly dependent on the amount of EAF dust consumed, rather than the amount of zinc produced. Collecting the total annual EAF dust consumed for all Waelz kilns at facilities would allow the EPA to develop a more accurate emission factor for facilities using Waelz kilns for the Inventory.

Reporters currently estimate emissions using either a CEMS direct measurement methodology or calculate process CO_2 emissions by determining annually the total mass of carbon-containing input materials (including zinc-bearing material, flux, electrodes, and any other carbonaceous materials) introduced into each kiln and furnace and the carbon content of each material. Of these materials, the proposed data element would only require segregation and reporting of the mass of EAF dust consumed for all kilns. Reporters currently collect information on the EAF dust consumed on a monthly basis as part of their existing operations; reporters using the mass balance methodology collect this data as a portion of the inputs to equation GG–1. We are not proposing any changes to the mass calculation methodology; reporters

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[128] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019* (EPA 2021), available at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019.*

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

would 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. Therefore, we do not anticipate that the proposed data elements would require any additional monitoring or data collection by reporters. The proposed data requirement would be required for reporters using either the CEMS direct measurement or mass balance calculation methodologies. We are also proposing related confidentiality determinations for the additional data elements, as discussed in section VI of this preamble.

Q. Subpart HH—Municipal Solid Waste Landfills

For the reasons described in section II.A.1 of this preamble, we are proposing revisions to subpart HH of part 98 (Municipal Solid Waste Landfills) that would improve the quality of the data collection under the GHGRP. First, we are proposing to update the factors used in modeling CH_4 generation from waste disposed at landfills to reflect the increased amount of inert materials that are disposed at landfills that do not contribute to CH_4 generation. The updated factors would allow MSW landfills to more accurately model their CH_4 generation.

Subpart HH uses a first order decay model to estimate CH_4 generation from MSW landfills. This model 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 of subpart HH contains 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 options available under the current rule can generally be summarized as follows:

- The Bulk Waste option assumes a single stream of waste coming into the facility that contains a mixture of organic and inorganic wastes. The current default DOC for this waste stream is 0.20, and the default decay rate values for this bulk waste stream are dependent on precipitation rates: 0.02 for <20 inches of rainfall per year; 0.038 for 20–40 inches of rainfall per year; and 0.057 for >40 inches of rainfall per year.
- The Modified Bulk MSW option allows facilities to break out their waste into three different streams: bulk MSW excluding inert and construction and demolition (C&D) wastes (effectively ‘‘organic MSW’’); C&D waste; and inert waste. The decay rates for the ‘‘organic MSW’’ stream are the same as those listed for the Bulk Waste option, however the default DOC is a higher value of 0.31. This value was calculated from the waste quantities reported in the EPA's ‘‘Municipal Solid Waste in the United States: 2007 Facts and Figures’’ report[130] specifically for the GHGRP considering only the organic containing portions of MSW.
- The Waste Composition option provides defaults for DOC and k for several subcategories of waste including food waste, garden waste, paper waste, wood waste, inert waste, etc. The DOC and k values for different subcategories of wastes are based on the values recommended in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5 Waste, Chapters 2 and 3.[131] Reporters are allowed to use the waste composition option for those waste streams for which compositional data are available and use the bulk waste defaults (DOC and k values as described in the Bulk Waste option above) for waste streams where compositional data are not available.

The EPA has received comments from stakeholders in the waste industry (*i.e.,* Waste Management, Republic Services, National Waste & Recycling Association, Solid Waste Association of North America, SCS Engineers, and Weaver Consulting Group) related to the values for DOC and k for both the Bulk Waste and Modified Bulk Waste Options listed under Table HH–1 to subpart HH. These comments[132] were received during the expert and public comment review period for the U.S. GHG Inventory. The U.S. GHG Inventory for solid waste uses directly reported emissions values from subpart HH to estimate national CH_4 emissions from MSW landfills throughout the entire United States, and the commenters noted that, in order to implement these suggested revisions to the U.S. GHG Inventory, revisions must first be made to subpart HH. Commenters argued, based on alleged fundamental shifts in the characterization of waste disposed in landfills and research conducted by state agencies and the Environmental Research and Education Foundation (EREF),[133] that: (1) the default DOC values for Bulk Waste and Modified Bulk Waste overestimate the organic fraction of waste in U.S. landfills and therefore overestimate emissions from this source; and (2) that the EPA should perform an analysis of data reported to subpart HH and update the default k values as necessary based on the results of this analysis. Commenters noted that the default values for k currently listed in Table HH–1 of subpart HH for both the Bulk Waste and Modified Bulk Waste options are based on data from the EPA's 2008 draft AP–42: Compilation of Air Emissions Factors[134] (which is still in draft form) and stated these default values are likely out-of-date considering changes in waste disposal trends in the past two decades.

In response, the EPA performed a multivariate analysis to minimize the difference between CH_4 generation estimates back-calculated from the reported values of equation HH–7 and the CH_4 generation predicted using equation HH–1, while optimizing k and DOC simultaneously for each landfill included in the analysis cohort. Six years of GHGRP data for 355 landfills were ultimately analyzed in this cohort. These 355 landfills were subpart HH reporters that reported a gas collection system (GCS) installed on-site for all reporting years, reported a consistent waste categorization option for all reporting years, and reported the same DOC and decay rate values for all reporting years. 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.

After consideration of the comments received and the multivariate analysis

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[130] U.S. EPA, Municipal Solid Waste in the United States: 2007 Facts and Figures, 2007. *https://archive.epa.gov/epawaste/nonhaz/municipal/web/pdf/msw07-rpt.pdf.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[131] IPCC. Guidelines for National Greenhouse Gas Inventories, Volume 5 Waste, 2006. *https://www.ipcc-nggip.iges.or.jp/public/2006gl/.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[132] See Waste Management, Republic Services, National Waste & Recycling Association, Solid Waste Association of North America, SCS Engineers, and Weaver Consulting Group. Comments on the 1990–2017 Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks EPA–HQ–OAR–2018–0853. March 14, 2019. These and other similar comments are in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[133] The Environmental Research & Education Foundation (2019). Analysis of Waste Streams Entering MSW Landfills: Estimating DOC Values & the Impact of Non-MSW Materials. Retrieved from *www.erefdn.org.* Available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[134] U.S. EPA. 2008. AP–42: Compilation of Air Emissions Factors, Fifth Edition, Volume 1, Chapter 2.4: Municipal Solid Waste Landfills. *https://www3.epa.gov/ttn/chief/ap42/ch02/index.html.* Also available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

performed, we are proposing to amend subpart HH to provide revised DOC and k values that would more accurately estimate GHG emissions from the MSW landfills. We are proposing to amend the bulk waste DOC value in Table HH–1 from 0.20 to 0.17, which was the average optimal DOC value for all landfills reporting under the Bulk Waste option (n=239) in the multivariate analysis. This value is similar to the proposed bulk waste DOC value of 0.161 the waste industry has cited within their comments as a result of study produced by the EREF (2016). We are proposing to use the results of the multivariate analysis in lieu of using the EREF recommended DOC value because the multivariate analysis is more nationally representative. EREF develop their recommended DOC value using state-level data for a single year (2013) for 14 states. The multivariate analysis based on subpart HH reported data uses facility-level data covering 41 states over the course of 6 years (2012–2017).

It was not possible to use the multivariate analysis to develop an optimal DOC value for bulk MSW waste without inerts and (C&D) waste for the Modified Bulk Waste option due to a lack of reporters that used this option meeting the criteria developed and noted above for the multivariate analysis. Instead, we reanalyzed the DOC value for this option using the same approach used to develop this factor initially but with updated MSW composition data from 2011 to 2015 as reported by the EPA.[135] The average DOC value across the 5-year period considering all MSW landfilled is 0.17, which agrees well with our optimized DOC value for bulk MSW from the multivariate analysis. After subtracting out inerts, the average DOC for MSW excluding inerts is 0.27.[136] The percent reduction of the DOC value for MSW excluding inerts is similar to the percent reduction in the average DOC for bulk MSW as determined from the multivariate analysis. Therefore, we are also proposing to revise the DOC value for the Modified Bulk MSW option in Table HH–1 from 0.31 to 0.27.

The EPA is also proposing to include a DOC value for ‘‘Uncharacterized MSW’’ within the Waste Composition option in Table HH–1. Currently, reporters using this option use the DOC provided for the Bulk Waste option for these uncharacterized waste streams as provided in 40 CFR 98.343(a)(2). A multivariate analysis of the facilities that use a hybrid approach of the Waste Composition option and the Bulk Waste option indicates that the optimal DOC value for uncharacterized MSW is much greater than the value for bulk DOC. The multivariate analysis indicates an optimal DOC value for uncharacterized DOC when using the waste composition option of 0.32. Therefore, we are proposing to include within Table HH–1 a DOC for uncharacterized MSW of 0.32 and proposing to revise 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. Details of this analysis are available in the memorandum, *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,* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

We note that DOC and k values are linked. Appropriate k values are primarily dependent on the composition of the waste and on the moisture content of the waste within the landfill (2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5 Waste, Chapter 3), which is why subpart HH includes different k values based on annual precipitation rates. The multivariate analysis we conducted determined the optimal values for DOC and k values when varying both parameters. The optimal DOC value for bulk waste would have been higher if we had conducted a single variable analysis and had used only the k values currently provided in Table HH–1. Because of this linkage between the DOC and k values, the EPA is also proposing to revise the default decay rate values in Table HH–1 for both the Bulk Waste option and the Modified Bulk MSW option and add k value ranges for uncharacterized MSW for the Waste Composition Option as shown in Table 4 of this preamble. The proposed defaults represent the average optimal k values for the cohort of landfills within each precipitation category. The proposed k values are larger than the current defaults but provide a more accurate estimate of the landfill's emissions based on the results of the multivariate analysis. We also reviewed the k values used in other countries' inventories as well as those recommended in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. We found that the current k values in Table HH–1 were low compared to those used in other countries with climates similar to that in the U.S. We also found that the k values we are proposing more closely align with those used in countries with similar climates to the U.S. and with the defaults for moderately decaying bulk waste provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.[137] Because our review of other inventory k values and our multivariate analysis indicate that the current k values in Table HH1 are too low, we are proposing to revise these k values consistent with the results of our multivariate analysis and consistent with our revision to the default DOC for bulk waste.

TABLE 4—PROPOSED DEFAULT k VALUES

Factor	Current subpart HH default	Proposed subpart HH default	Units
k values for Bulk Waste option and Modified Bulk MSW option			
k (precipitation plus recirculated leachate <20 inches/year)	0.02	0.055	yr − 1
k (precipitation plus recirculated leachate 20–40 inches/year)	0.038	0.111	yr − 1
k (precipitation plus recirculated leachate >40 inches/year)	0.057	0.142	yr − 1

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[135] U.S. EPA. 2015. Advancing Sustainable Materials Management—2015 Tables and Figures: Assessing Trends in Material Generation, Recycling, Composting, Combustion with Energy Recovery and Landfilling in the United States July 2018, available at: *https://www.epa.gov/facts-and-figures-about-materials-waste-and-recycling/advancing-sustainable-materials-management.* Data set from 1960 to 2015 (see ''Materials_Municipal_Waste_Stream_1960_to_2015.xlsx'') available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[136] See memorandum from Jeff Coburn, RTI International, to Rachel Schmeltz, EPA, *Modified Bulk MSW Option Update,* June 18, 2019, available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424).

[137] See memorandum from Kate Bronstein and Meaghan McGrath, RTI International to Rachel Schmeltz, EPA, *Comparison of U.S. Inventory Waste Model Decay Rate (k) Values to Other UNFCCC Annex 1 Country Defaults and Country-specific Waste Models* (June 18, 2019), available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

TABLE 4—PROPOSED DEFAULT K VALUES—Continued

Factor	Current subpart HH default	Proposed subpart HH default	Units
k value range for Waste Composition option			
k (uncharacterized MSW)	Not applicable	0.055 to 0.142	yr − 1

Altering both the default DOC and k values for subpart HH reporters would affect closed and open landfills in different ways. Implementing the recommended, and higher, k values will serve to increase the emissions calculated from equation HH–1 and equation HH–5 for open, active landfills. The higher k values imply that the organic material that is placed in the landfill will degrade more quickly than predicted when using lower k-values. This tends to lead to greater calculated emissions from active landfills (landfills actively receiving waste during a reporting year). The higher k values also tend to predict that less degradable waste will be in the landfill once the landfill closes (*i.e.,* no longer receives wastes) and the degradable waste that is present in the closed landfill will decompose more quickly. This tends to reduce the emissions calculated for closed landfills, which may allow closed landfills to more quickly phase-out of the reporting program (*i.e.,* when reported emissions fall below the 25,000 mtCO$_2$e threshold for 5 years consecutive years). Thus, the proposed k values are expected to increase the calculated emissions from active landfills, reduce calculated emissions from closed landfills, and potentially reduce burden associated with the reporting requirements for closed landfills (due to having fewer years of reported emissions above the reporting threshold once the landfill is closed). We also note that the emissions from the landfill over its entire life (active and closed periods) is dependent only on the amount of degradable organic material placed in the landfill, which is dependent only on the DOC value. Thus, the lower DOC value should reduce the cumulative emissions reported for a given landfill over all reporting years; however, it may increase the emissions reported during the years the landfill is actively receiving wastes.

To determine an estimate of the effect of these changes on overall subpart HH emissions reporting, equation HH–1 methane generation from six landfills in the final analysis cohort, three closed landfills (one in each precipitation range) and three open landfills (one in each precipitation range), were recalculated (as an illustrative example) with the recommended DOC value of 0.17 and the recommended k value corresponding to the landfill's precipitation zone.[138] On average, the selected closed landfills had a 21 percent decrease in methane generation while the selected open landfills saw a 55 percent increase. These are illustrative examples and not a quantitative nationwide assessment of the impact of the proposed revisions to DOC and k values, but they confirm our expectations. The nationwide impact of these changes will likely be limited to a large extent because the large majority (approximately 90 percent) of the emissions reported under subpart HH are from facilities with GCS. Facilities with GCS use two different calculation methodologies to determine methane emissions: equation HH–6, which used the predicted methane generation from equation HH–1 and the amount of methane recovered, and equation HH–8, which is based solely on the quantity of methane recovered. Per 40 CFR 98.346(i)(13), facilities with GCS may then choose the equation result that best represents emissions from the landfill to use as their total methane emissions reported for subpart HH. About 71 percent of subpart HH facilities in RY2020 used equation HH–8 to estimate their methane emissions and the proposed revisions would not impact the emissions reported for these facilities. Thus, the proposed revisions would impact only the emissions from landfills without GCS and landfills with GCS that elect to report emissions using equation HH–6, which is a smaller fraction (about 35 to 40 percent) of the total methane emissions reported subpart HH. While methane emissions reported by active landfills not using equation HH–8 are expected to increase, the methane emissions reported by closed landfills are expected to decrease, and the total amount of methane reported to be generated by a given landfill over its entire life is expected to decrease (based on the proposed lower DOC value).

For the reasons described in section II.A.4 of this preamble, we are proposing a reporting requirement for landfills with gas collection and control systems to inform the development of GHG policies and programs by providing information on the proportion of landfill gas used in energy recovery projects. There is no anticipated significant change in burden due to this reporting requirement because key data in estimating the annual amount of recovered CH$_4$ from data reported by measurement location and destruction device are already reported. Specifically, we are proposing to require landfills with gas collection and control systems to indicate the percentage of recovered CH$_4$ that is sent to a flare or sent to a landfill gas to energy project for each measurement location.

For landfills with gas collection and control systems, we currently collect the following information under 40 CFR 98.346(i) related to the gas collection and control system at the facility: total volumetric flow of landfill gas collected for destruction, the annual average CH$_4$ concentration of landfill gas for destruction, and an indication of whether destruction occurs at the landfill facility, off-site, or both. For landfills where destruction occurs at the facility, we also ask for information about the measurement location(s) and destruction device(s) at the facility. This information includes the number of destruction devices associated with each measurement location, the annual operating hours of each measurement location and its associated destruction devices, and the annual quantity of recovered CH$_4$ using equation HH–4 for each measurement location. We do not collect specific information about destruction devices located off-site and therefore cannot collect the annual quantity of CH$_4$ recovered using equation HH–4 at the destruction device level for all facilities subject to subpart HH. Therefore, we are proposing to collect information at the measurement location level about the proportion of landfill gas that is flared versus sent to a landfill gas to energy project. Specifically, we are proposing at 40 CFR

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[138] 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.

98.346(i)(6)(i) to require landfills with gas collection and control systems to indicate the percentage of recovered CH_4 that is flared or sent to a landfill gas to energy project for each measurement location. We understand that a facility owner or operator may not know the exact quantity of recovered CH_4 sent off-site for destruction by a flare or landfill gas to energy project. Facilities that indicate off-site destruction in e-GGRT and do not know whether the recovered gas sent to the off-site destruction device is sent to a flare or landfill gas to energy project would be allowed to allocate the off-site portion of recovered gas into an ''unknown'' option along with an optional text description.

This information would help inform the development of GHG policies and programs under the CAA by providing information on the amount of recovered CH_4 that is beneficially used in energy recovery projects and will assist in verification of net CH_4 emissions from landfills with gas collection and control systems. This new requirement will also assist with QA/QC of required inputs into the U.S. GHG inventory for MSW landfills and will inform EPA, state, and local government officials on progress towards renewable energy targets and GHG emission inventories. Additionally, researchers have requested this information under the U.S. national solid waste inventory. We are also proposing related confidentiality determinations for the new data element, as discussed in section VI of this preamble.

R. Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

For the reasons discussed in section II.B.3 of this preamble, the EPA is proposing to streamline reporting requirements by eliminating some duplicative reporting between subpart NN (Suppliers of Natural Gas and Natural Gas Liquids) and subpart W (Petroleum and Natural Gas Systems) by eliminating the duplicative elements from subpart W, as discussed in section III.J.2.f of this preamble.

S. Subpart OO—Suppliers of Industrial Greenhouse Gases

For the reasons provided in section II.A.4 of this preamble, we are proposing revisions to subpart OO of part 98 (Suppliers of Industrial Greenhouse Gases) that would improve the quality of the data collection under the GHGRP. First, we are proposing to add a requirement for bulk importers of F–GHGs to include, as part of the information required for each import in the annual report, the customs entry summary number. The customs entry summary number is provided as part of the U.S. Customs and Border Protection (CBP) Form 7501: Entry Summary[139] and is assigned for each filed CBP entry for each shipment. We are proposing to gather this data, which is already available in supplier records, to verify and compare the data submitted to the GHGRP with other available customs data. The proposed customs entry summary number would provide a means to cross-reference the data submitted and would help to ensure the accuracy and completeness of the information reported under the GHGRP. The proposed changes would modify 40 CFR 98.416(c)(7). Because the information collected is readily available in supplier records and is similar to the identifying information currently collected (*i.e.,* date of import, port of entry, country, commodity code, and importer number), there is no anticipated significant change in burden.

Additionally, the EPA is proposing to require at 40 CFR 98.416(k) that suppliers of N_2O, saturated PFCs, and SF_6 identify the end uses for which the N_2O, SF_6, or PFC is used and the aggregated annual quantities of N_2O, SF_6, or each PFC transferred to each end use, if known. This requirement, which is patterned after a similar requirement under subpart PP (Suppliers of Carbon Dioxide) of part 98, would help to inform the development of GHG policies and programs by providing information on N_2O, SF_6, and PFC uses and their relative importance. We are proposing the requirement for N_2O, SF_6, and PFCs in particular because: (1) the GWP-weighted quantities of these compounds that are supplied annually to the U.S. economy are relatively large; and (2) the identities and magnitudes of the uses of these compounds are less well understood than those of other industrial GHGs such as HFCs. For example, most N_2O is believed to be used for anesthetic applications, but the exact share used for these applications is not known. SF_6 is known to be used in electrical equipment, magnesium production and processing, and electronics manufacturing, but the total quantity of SF_6 that is estimated to be consumed by these applications has sometimes fallen significantly below the total quantity of SF_6 supplied annually to the U.S. economy from 2011 through 2019, indicating that significant uses of SF_6 may not be accounted for. Collecting information from suppliers of these compounds on how their customers use the compounds, and in what quantities, would help to resolve these questions.

To inform the revision of the subpart OO electronic reporting form in the event that this proposed amendment is finalized, we request comment on the end use applications for which N_2O, SF_6, and saturated PFCs are used and their relative importance. The EPA is aware of the following end uses of N_2O:

(1) Analgesia or anesthesia, including medical, dental, and veterinary uses,
(2) Oxidizer in fuel,
(3) Foaming agent (*e.g.,* for use in aerosol whipped cream),
(4) Propellant in aerosol sprays,
(5) Electronics manufacturing, including manufacturing of semiconductors (including light-emitting diodes), micro-electro-mechanical systems, liquid crystal display, and photovoltaic cells.

The EPA is aware of the following end uses of SF_6:

(1) Electrical equipment use (*i.e.,* by electric transmission and distribution systems),
(2) Electrical equipment manufacturing,
(3) Electronics manufacturing, including manufacturing of semiconductors (including light-emitting diodes), micro-electro-mechanical systems, liquid crystal display, and photovoltaic cells,
(4) Magnesium production and processing,
(5) Dielectrics for particle accelerators, including university and research particle accelerators, industrial particle accelerators, and medical particle accelerators,
(6) Radar systems,
(7) Adiabatic uses, including use in shoe soles and car tires,
(8) Sound-proof windows,
(9) Tracer gas, including leak detection,
(10) Waterproofing (*e.g.,* of textiles and/or circuit boards),
(11) Other medical applications.

The EPA is aware of the following end uses of saturated PFCs:

(1) Electronics manufacturing, including manufacturing of semiconductors (including light-emitting diodes), micro-electro-mechanical systems, liquid crystal display, and photovoltaic cells,
(2) Heat transfer fluids,
(3) Electrical equipment use,
(4) Electrical equipment manufacturing,
(5) Adiabatic uses, including use in shoe soles and car tires,
(6) Cosmetic applications,
(7) Medical applications,

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[139] CBP Form 7501 is available at the U.S. Customs and Border Protection website (*https://www.cbp.gov/trade/programs-administration/entry-summary/cbp-form-7501*).

(8) Waterproofing (*e.g.,* of textiles and/or circuit boards).

We request comment on the above list and any additional end-uses of GHGs that should be considered for inclusion in the reporting form.

Finally, we are proposing a clarification to the reporting requirements for importers and exporters of F–GHGs, F–HTFs, or N_2O, for the reasons provided in section II.A.5 of this preamble. We are proposing 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. Importers and exporters currently provide the commodity code as part of the annual summary information provided for each import or export at the corporate level. The majority of reporters provide a commodity code based on codes assigned through the HTS, which assigns 10-digit codes to identify products that are unique to U.S. markets. HTS codes start with a 6-digit code specifying a chapter, heading, and subheading, and in full include a specific 10-digit code including a subheading for duty and a statistical suffix. However, in some cases the requirement has apparently been unclear to and misread by reporters, and reporters may identify shipments using other commodity code systems, such as the abbreviated 6-digit codes assigned by the international Harmonized System (HS) or Standard Industrial Classification System (SIC), or may enter other unidentifiable data into the ''commodity code'' field. Reporters may also enter the data in different formats (*e.g.,* with or without decimals). This has resulted in cases in which the data provided in some annual reports is unclear or unable to be compared to outside data sources for verification. In order to reduce confusion for reporters and standardize the data received we are proposing to replace ''commodity code'' with ''Harmonized Tariff System code'' in 40 CFR 98.416(c)(6) and 40 CFR 98.416(d)(4). Reporters would enter the full 10-digit HTS code with decimals, to extend to the statistical suffix, as it was entered on related customs forms. For example, in 2020, the entry for ''1,1,1,2-Tetrafluoroethane (HFC–134a)'' would be ''2903.39.20.20''.[140] The proposed clarifications would reduce the uncertainty associated with the reported data elements and improve data verification.

We are also proposing related confidentiality determinations for the new and revised data elements, as discussed in section VI of this preamble.

T. Subpart PP—Suppliers of Carbon Dioxide

For the reasons discussed in section II.A.3 of this preamble, the EPA is proposing several revisions to subpart PP of part 98 (Suppliers of Carbon Dioxide) to improve the quality of the data collected from this subpart. Subpart PP is intended to identify and quantify supplies of CO_2 to commercial applications, underground injection, or geologic sequestration. Subpart PP currently requires reporting of the annual quantities of CO_2 supplied by pipeline and in containers from natural sources (*i.e.,* extraction wells), capture sources, and importers/exporters. Capture sources include natural gas processing plants, ethanol manufacturing facilities, and other types of facilities where CO_2 is captured and supplied for commercial applications or to inject or sequester underground.

Direct air capture (DAC) is a new, innovative approach to capturing CO_2 from ambient air. 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. CO_2 is separated from air using aqueous or solid sorbents and then processed into a concentrated stream for utilization or injection underground. Historically a niche or experimental technology, interest in deploying DAC technology has grown significantly in recent years as a technology to address climate change.

We are proposing to add a new paragraph 40 CFR 98.420(a)(4), to explicitly include DAC as a capture option. In addition, we are proposing to amend 40 CFR 98.6, to include a definition for DAC. Specifically, we are proposing 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 definition is taken directly from the definition of DAC in the CAA at 42 U.S.C. 7403(g)(6)(B)(III).[141] We believe these clarifications will benefit owner/operators of DAC facilities, the public, and other stakeholders by removing any questions or uncertainty about the applicability of subpart PP to DAC. Moreover, the proposed amendments will improve data quality by clarifying applicability of subpart PP, thereby ensuring the GHGRP accounts for a growing and potentially large component of the CO_2 supply chain.

To ensure consistency among definitions applicable to subpart PP, we are also proposing to amend the definition of ''Carbon dioxide stream'' in 40 CFR 98.6 to include DAC in the definition. Specifically we are proposing 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 also proposing to amend other sections of subpart PP to explicitly include DAC as a capture source for consistency with the proposed changes to 40 CFR 98.420 and 40 CFR 98.428. Specifically, we are proposing to amend the following sections to add references to DAC: 40 CFR 98.422; 40 CFR 98.423; 40 CFR 98.426; and 40 CFR 98.427.

In addition to these changes, we are proposing one additional reporting requirement in 40 CFR 98.426 to improve data quality with respect to DAC facilities. Life Cycle Analysis (LCA) has become a very important tool in determining the net impact of DAC projects. DAC processes potentially require substantial quantities of energy to capture, process and supply CO_2; therefore, we believe it is important for the public and the EPA to understand the sources and amounts of energy used by DAC facilities to power the DAC plant from air intake at the facility through custody transfer of captured CO_2 or, if the CO_2 does not leave the facility, injection of captured CO_2. We are proposing to add a new requirement at 40 CFR 98.426(i) to require DAC facilities to report the amounts of on-site and off-site sourced electricity, heat and combined heat and power used to power the DAC plant from air intake at

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[140] A complete list of codes and current HTS Chapters can be found at *https://hts.usitc.gov/current.*

[141] The definition of DAC was added to the CAA as part of the Utilizing Significant Emissions with Innovative Technologies Act (USE IT Act), which was included in Section 102 of Division S of the Consolidated Appropriations Act, 2021, available at *https://www.congress.gov/116/bills/hr133/BILLS-116hr133enr.pdf.*

the facility through the point of compressed CO_2 stream ready for supply for commercial applications or, if maintaining custody of the CO_2 stream, sequestration or injection of the CO_2. In addition, for on-site sourced electricity, heat and combined heat and power, we are proposing that DAC facilities indicate whether flue gas is also captured by the DAC process unit. We are additionally proposing related confidentiality determinations for the new data elements, as discussed in section VI of this preamble.

U. Subpart SS—Electrical Equipment Manufacture or Refurbishment

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

For the reasons discussed in section II.A of this preamble, we are proposing several revisions to subpart SS of part 98 (Electrical Equipment Manufacture or Refurbishment) to improve the quality of the data collected from this subpart. Currently, this subpart requires reporting of emissions from manufacturing and refurbishing processes that include SF_6 and PFCs. We are proposing to revise the existing 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. As discussed in section III.N of this preamble, although SF_6 and PFCs have been the most commonly used insulating gases in the electrical power industry, over the implementation of the reporting program the EPA has become aware of alternative technologies and replacements for SF_6, including fluorinated gas mixtures. Therefore, we expect that electrical equipment manufacturers and refurbishment operations, in addition to electric power systems and facilities, include equipment or are anticipated to include equipment containing these alternative gas mixtures (*e.g.,* fluoronitrile or fluoroketone mixtures). As such, we are proposing revisions to subpart SS in order to capture emissions from equipment using these alternative gases that are not currently accounted for. The proposed reporting of these additional F–GHGs would improve the accuracy of emissions reported under subpart SS and enhance the overall quality of the data collected under the GHGRP.

To implement these revisions, we are proposing to 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 proposed changes would also apply to the threshold in 40 CFR 98.451. Under the proposed rule, facilities would also consider additional F–GHGs purchased by the facility in estimating emissions for comparison to the threshold. There are no known facilities that currently use the alternative gas mixtures exclusively or in large quantities that would render them newly subject to the subpart; therefore, we expect the proposed changes would result in minimal burden for reporters.

The proposed revisions to subpart SS include minor revisions to equations SS–1 through SS–6 (which we are proposing be renumbered SS–2 through SS–7 to accommodate a new equation SS–1 as discussed in section III.U.2 of this preamble) to incorporate the estimation of emissions from all F–GHGs within the existing calculation methodology, 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 proposing a definition of ''insulating gas'' and proposing 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 proposed changes do not significantly revise the existing calculation requirements. Although the revisions do require additional monitoring and reporting requirements (including, but not limited to, the tracking of alternative gases in a facility's inventory, purchases of alternative gases, and the delivery of equipment containing alternative gases), there are no known facilities that currently manufacture large quantities of electrical transmission and distribution equipment that use alternative gas mixtures in the U.S.; therefore, we expect only a minimal increase in burden due to the collection of data for any equipment containing F–GHGs that are not SF_6 or PFCs. However, we expect that the use of alternative gases will continue to increase and collection of this data is important to both understand emission trends and account for total emissions from the sector. Finally, we are proposing related confidentiality determinations for the revised data elements that incorporate additional F–GHGs, as discussed in section VI of this preamble.

2. Proposed Revisions to Streamline and Improve Implementation for Subpart SS

For the reasons described in section II.B.1 of this preamble, we are proposing to revise the applicability threshold of subpart SS. The proposed revisions would 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 metric tons of CO_2 threshold by introducing a new equation, equation SS–1. To accommodate this new equation, we are also proposing minor harmonizing changes to renumber existing equations SS–1 through SS–6 and related cross-references. Subpart SS currently requires facilities that have total annual purchases of SF_6 and PFCs that exceed 23,000 pounds to report. The EPA established the annual consumption-based threshold of 23,000 pounds in the 2010 Final Rule for Additional Sources of Fluorinated GHGs (75 FR 74774) as an ''equivalent threshold'' that approximated the 25,000 metric tons of CO_2 threshold. Emissions of SF_6 and PFC from the source category include emissions from the testing, manufacturing, and installation or commissioning of equipment, but can also occur when equipment is decommissioned at a manufacturing facility. The current threshold was based on an average emission rate estimated at approximately 10 percent[142] and the GWP for SF_6 referenced in the 2009 Final Rule from the IPCC Second Assessment Report. Since that time, the GWP for SF_6 has been updated in the GHGRP to a lower value (78 FR 71904, November 29, 2013). Further, some facilities within this industry sector have begun to use lower GWP F–GHGs, which are currently not accounted for in subpart SS. Therefore, we are proposing to revise the applicability threshold to align with the proposed revisions to require reporting of additional F–GHG beyond SF_6 and PFCs. The proposed equation SS–1 would continue to be based on the total annual purchases of insulating gases, but would establish an updated comparison to the threshold, and would account for the additional

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[142] The 10 percent emission rate was based on the average of ''ideal'' and ''realistic'' manufacturing emission rates (4 percent and 17 percent, respectively) identified in a paper prepared under the auspices of the International Council on Large Electric Systems (CIGRE) in February 2002 (O'Connell, P., F. Heil, J. Henriot, G. Mauthe, H. Morrison, L. Neimeyer, M. Pittroff, R. Probst, J.P. Tailebois (2002) SF_6 in the Electric Industry, Status 2000, Cigre. February 2002.), available at *https://www.epa.gov/sites/default/files/2016-02/documents/conf02_pittroff.pdf* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. This method for estimating OEM emissions was the same method used in EPA's Inventory of Greenhouse Gas Emissions and Sinks:1990–2006 (EPA 2008). Available at: *https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2006* (accessed September 15, 2021).

fluorinated gases reported by industry. Potential reporters would be required to account for the total annual purchases of all insulating gases, and multiply by the GWP for each F–GHG and the emission factor of 0.10 (or 10 percent). We have determined that the proposed threshold methodology is more appropriate because it represents the actual fluorinated gases used by a reporter. The proposed revisions would also streamline the reporting requirements to focus Agency resources on the substantial emission sources within the sector. Additionally, the proposed changes would revise the inclusion of subpart SS in the existing Table A–3 to subpart A. Because we are proposing to provide a method for direct comparison to the 25,000 $mtCO_2e$ threshold, we are proposing to remove subpart SS from Table A–3 and include the subpart in Table A–4 of subpart A. Including subpart SS in Table A–4 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. Currently reporters determine the applicability of subpart SS under 40 CFR 98.2(a)(1), which applies to source categories listed in Table A–3. Therefore, facilities determine the applicability of subpart SS on the basis of the current consumption-based threshold without consideration of the combined emissions from stationary fuel combustion sources (subpart C), miscellaneous use of carbonates (subpart U), and other applicable source categories towards the threshold. Moving this subpart to Table A–4 of subpart A would 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. The change from Table A–3 to Table A–4 is not expected to result in additional reporters under subpart SS. Although most facilities subject to subpart SS also report under subpart C, the reported subpart C emissions are typically less than 1000 $mtCO_2e$ and are not a significant portion of the total facility emissions.

V. Subpart UU—Injection of Carbon Dioxide

The EPA is proposing one amendment to subpart UU to ensure consistency with new proposed subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916). Subpart VV is described further in section III.W of this preamble. The proposed rule change adds language to 40 CFR 98.470, Definition of the source category, to clarify that reporters who report under subpart VV for a well or group of wells are not required to report under subpart UU for that well or group of wells. Proposed new 40 CFR 98.470(c) is similar to existing language in 40 CFR 98.470(b) which provides that reporters to the Geologic Sequestration of Carbon Dioxide source category of the GHGRP (subpart RR) for a well or group of wells are not required to report under subpart UU for that well or group of wells.

We are proposing this revision to reduce the reporting burden on subpart VV reporters by eliminating duplicative reporting requirements. This proposed rule change also improves data quality by avoiding double counting of the quantities of CO_2 received and injected at EOR and enhanced gas recovery facilities that use the CSA/ANSI ISO 27916:2019 standard and choose to report under subpart VV. This avoidance of double counting would allow the EPA and the public to better track and document the flow of CO_2 through the economy.

In proposing this change, we are also proposing to renumber existing 40 CFR 98.470(c) to 40 CFR 98.470(d); however, we are not proposing any rule language changes to this paragraph.

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

The GHGRP is proposing to add a new subpart—subpart VV—as an option for quantifying geologic sequestration in association with EOR operations using the ISO standard designated as CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2–EOR).* Although the title of the standard references only EOR, Clause 1.1 of CSA/ANSI ISO 27916:2019 indicates that the standard can apply to enhanced gas recovery as well. Thus, throughout subpart VV, as proposed, any reference to EOR also applies to enhanced gas recovery.

Carbon capture, utilization, and sequestration (or storage) (CCUS) refers to a set of technologies that remove CO_2 from the emissions of point sources or the atmosphere, and transport it, compress it, and inject it deep underground, or transform it for utilization in industrial processes or as feedstock for products. Geologic sequestration is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, where CO_2 can be injected to increase oil production through a process referred to as EOR.

Subpart RR (Geologic Sequestration of Carbon Dioxide) is currently the only source category within the GHGRP that provides an accounting framework to report to the EPA the amount of CO_2 geologically sequestered on an annual basis. The GHGRP's geologic sequestration data are integral to providing transparent information to the EPA and the public to track the value chain of CO_2 supply and disposition.

The definition of the source category for subpart RR includes a well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations. It also includes wells permitted by the UIC Program as Class VI wells. Facilities that conduct EOR are not required to report under subpart RR unless the owner or operator chooses to opt-in to subpart RR, or the well is permitted as a Class VI well. An operator that does not choose to opt into subpart RR must report under subpart UU (Injection of Carbon Dioxide) of the GHGRP.

Facilities subject to subpart RR are required to develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan. The major elements of the MRV plan include: (1) delineation of active and maximum monitoring areas; (2) identification of potential surface leakage pathways for CO_2; (3) a strategy for detecting and quantifying surface leakage of CO_2; (4) a strategy for establishing the expected baseline for monitoring CO_2 leakage; and (5) definition of site-specific variables that will be used for estimating leakage. Once the facility has an approved MRV plan, reporters are required to report annually the amount of CO_2 received, the data used to calculate this amount, the source of the received CO_2 (if known), the mass balance equation inputs (amounts of CO_2 injected, CO_2 produced, CO_2 emitted by surface leakage, CO_2 emitted from equipment leaks and vented CO_2 emissions), the data used to calculate the inputs, and the amount of CO_2 sequestered. Facilities are also required to submit an annual monitoring report which implements the reporting requirements set forth in the MRV plan.

Like subpart RR, subpart UU requires facilities to report the quantity of CO_2 received, the data used to calculate this amount, and the source of the received CO_2 (if known). However, subpart UU does not require an MRV plan or the submission of an annual monitoring report. Nor does it require monitoring or reporting of the fate of the CO_2 after the custody transfer meter, and thus does not provide an accounting framework of the amount of CO_2 sequestered.

In January 2019, ISO published a new international standard for CO_2 storage using EOR. The standard was subsequently endorsed by the CSA and ANSI and is designated as CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2–EOR)*''.[143] The standard establishes a protocol for documenting the containment of CO_2 injected in an EOR operation and quantifying the amount of CO_2 that is stored in association with that operation.

As part of the Bipartisan Budget Act of 2018, Congress revised the Internal Revenue Code (IRC) section 45Q tax credit for carbon oxide sequestration (45Q).[144] If a taxpayer meets the applicability requirements, section 45Q provides tax credits for disposal of qualified carbon oxide in secure geological storage or utilization. The amount of the tax credit for disposal of qualified carbon oxide in secure geological storage depends on whether the qualified carbon oxide is used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project.

Under a rule finalized by the Treasury Department and Internal Revenue Service (IRS),[145] qualified carbon oxide is considered disposed of by the taxpayer in secure geological storage such that the qualified carbon oxide does not escape into the atmosphere if the qualified carbon oxide is either: (1) injected into a well that complies with applicable UIC or other regulations, is located onshore or offshore under submerged lands within the territorial jurisdiction of states or federal waters, and is not used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project; and is stored in compliance with applicable requirements under subpart RR; or (2) injected into a well that complies with applicable UIC or other regulations, is located onshore or offshore under submerged lands within the territorial jurisdiction of states or federal waters, and is used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project and stored in compliance with applicable requirements under subpart RR or CSA/ANSI ISO 27916:2019.

For EOR facilities that choose CSA/ANSI ISO 27916:2019 for purposes of demonstrating secure geological storage for the IRC section 45Q tax credit, the IRS regulations require that documentation be provided to a qualified independent engineer or geologist, who then must certify that the documentation provided, including the mass balance calculations as well as information regarding monitoring and containment assurance, is accurate and complete. Under existing GHGRP requirements, reporters that choose CSA/ANSI ISO 27916:2019 for purposes of the section 45Q tax credit continue reporting under subpart UU of the GHGRP if they choose not to report under subpart RR.

Both subpart RR and CSA/ANSI ISO 27916:2019 require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. However, the inputs of the mass balance equations differ as between subpart RR and CSA/ANSI ISO 27916:2019. Specifically, the subpart RR mass balance equation for quantifying the amount of CO_2 that is geologically sequestered includes variables on injected CO_2; equipment leaks and vented CO_2 emissions from surface equipment between the flow meters and the wellhead; CO_2 produced and/or remaining with produced oil, gas, or other fluids; and CO_2 leakage to the surface. In contrast, under CSA/ANSI ISO 27916:2019, 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 CSA/ANSI ISO 27916:2019 standard defines the EOR complex 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 that are determined under the CSA/ANSI ISO 27916:2019 standard 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. Thus, a primary difference between subpart RR and CSA/ANSI ISO 27916:2019 relates to the terms in their respective mass balance equations.

There are other noteworthy differences between subpart RR and CSA/ANSI ISO 27916 as well. One is how they determine ''leakage.'' Subpart RR quantification is based on leakage of CO_2 to the surface, that is, emissions of CO_2 to the atmosphere. In contrast, CSA/ANSI ISO 27916:2019 considers leakage to be CO_2 that migrates outside of the EOR complex.

Another difference is the time when facilities may discontinue reporting. Under subpart RR, a facility may discontinue reporting if it demonstrates that current monitoring and model(s) show that the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage. Under CSA/ANSI ISO 27916:2019, the operator must demonstrate that the CO_2–EOR project is completed, based on (1) the cessation of CO_2 injection, (2) the cessation of hydrocarbon production from the project reservoir, and (3) the plugging and abandoning of wells, unless otherwise required by the appropriate regulatory authority.

Another, and, for present purposes, perhaps the most salient difference between subpart RR and CSA/ANSI ISO 27916:2019 is related to public transparency. The EPA publishes final decisions under subpart RR on its website, such as whether to approve an MRV plan or request for discontinuation of reporting. Any interested person can appeal subpart RR final decisions to the EPA's Environmental Appeals Board. In addition, the EPA also verifies the data submitted in annual GHGRP reports, including annual monitoring reports submitted under subpart RR, and publishes non-confidential data on the EPA website. In contrast, facilities that follow CSA/ANSI ISO 27916:2019 are not currently subject to requirements related to public reporting and transparency of amounts stored and associated documentation.

In comments to the IRS on the proposed IRC section 45Q regulations, several commenters supported the IRS's adoption of the CSA/ANSI ISO 27916:2019 ISO pathway, but were concerned that the ISO standard itself, as relied on by the IRS, does not contain the requirements for public disclosure and transparency of information necessary to allow the public to review the adequacy of the demonstration of secure geologic storage. Commenters also emphasized the importance and need for credible third-party audits and certifications, and government oversight and enforcement.[146] The IRS responded

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[143] Available at *https://www.iso.org/standard/65937.html* and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

[144] See 26 CFR 1.45Q–0 through 26 CFR 1.45Q–5.

[145] Internal Revenue Service, Treasury Department, Credit for Carbon Oxide Sequestration, Final Regulations (88 FR 4728, January 15, 2021), available at *https://www.govinfo.gov/content/pkg/FR-2021-01-15/pdf/2021-00302.pdf* (accessed September 7, 2021).

[146] See 85 FR 34050, 34055 (June 20, 2020).

that it is constrained by law concerning the public disclosure of information submitted by taxpayers.

Some stakeholders recommended that the EPA promulgate a new subpart to the part 98 regulations for GHGRP that would establish procedures for documenting and reporting the amount of carbon oxide securely stored using the CSA/ANSI ISO 27916:2019 methodology.[147] The reporting of this information to the EPA would ensure that the public has access to the relevant information in the same manner that the public currently has access to the information reported to the EPA under subpart RR. This reporting would also provide the EPA with complete data (that is, data from reporting under both subpart RR and CSA/ANSI ISO 27916:2019) to fully understand the amounts of CO_2 that are geologically sequestered for EOR.

Therefore, the EPA is proposing a new source category—subpart VV—related to the option for reporting of incidental CO_2 storage associated with EOR based on the CSA/ANSI ISO 27916:2019 standard. Specifically, facilities that conduct EOR would be required to report basic information on CO_2 received under subpart UU, or they could choose to opt-in to either subpart RR or the new subpart to quantify amounts of CO_2 that are geologically sequestered. The EPA seeks comment on this new proposed subpart VV.

The EPA is proposing that facilities would 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 27916:2019 methodology, and documentation providing the basis for that determination as set forth in CSA/ANSI ISO 27916:2019. Specifically, the reporting of documentation under subpart VV would involve providing the CSA/ANSI ISO 27916:2019 EOR Operations Management Plan (OMP), which is required to specify: (1) a geological description of the site, 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. The EOR OMP sets forth the operator's approaches for containment assurance and monitoring and provides the level of detail on operations and reporting that are comparable to an MRV plan submitted under subpart RR. Thus, annual reporting under subpart VV should specify any changes made to containment assurance and monitoring approaches and procedures in the EOR OMP made within the reporting year.

In addition, the EPA is proposing that reporters annually report the following information per CSA/ANSI ISO 27916:2019: (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 EPA is proposing to require that reporters to subpart VV 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. The EPA notes that regulations under IRC section 45Q require the EOR OMP and the data in the annual report be provided to a qualified independent engineer or geologist, who then must certify that the documentation, including the mass balance calculations as well as information regarding monitoring and containment assurance, is accurate and complete. However, the EPA is not proposing EPA approval of a third-party approved and certified EOR OMP and documentation. In contrast, subpart RR requires EPA approval of subpart RR MRV plans.

Under CSA/ANSI ISO 27916:2019, monitoring and reporting and associated recordkeeping is required to continue until the CO_2–EOR project is terminated, at which time the monitoring, reporting, and recordkeeping may cease. CSA/ANSI ISO 27916:2019 provides that CO_2–EOR project termination is completed when all of the following occur: CO_2 injection has ceased, hydrocarbon production from the project reservoir has ceased, and wells have been plugged and abandoned unless otherwise required by a regulatory authority. The EPA proposes that the time for cessation of reporting under subpart VV be the same as under CSA/ANSI ISO 27916:2019, and that the operator notify the Administrator of its intent to cease reporting and provide a copy of the CO_2–EOR project termination documentation.

Currently under the GHGRP, if an owner or operator chooses to opt in to reporting under subpart RR for a CO_2–EOR project, that owner/operator is no longer required to report under subpart UU for that CO_2–EOR project, in light of the fact that CO_2 received is reported under both subparts. Because CO_2 received would be an element in the mass balance equation under subpart VV for the mass of CO_2 input, the EPA proposes that if and when an operator begins reporting under subpart VV, that operator will no longer be required to report under subpart UU for that CO_2–EOR project.

IV. Additional Requests for Comment

The EPA is considering future revisions to the GHG Reporting Rule to potentially expand existing source categories or develop other new source categories that would add calculation, monitoring, reporting, and recordkeeping requirements related to energy consumption; ceramics production; calcium carbide production; glyoxal, glyoxylic acid, and caprolactam production; coke calcining; and CO_2 utilization. Based on our recent review of the data collected under the GHGRP and in consideration of data that are needed to continue to inform the EPA's understanding of GHG data and better inform future EPA policy and programs, we are considering revising part 98 to include these newly identified source categories. Therefore, the EPA is specifically requesting comment related to the potential expansion of existing source categories or development of new source categories described in this section. If the Agency decides that sufficient information is available to support a rule revision, the EPA may consider undertaking a future action to expand or add these new source categories.

In the development of the GHGRP, the EPA considered its authorities under CAA sections 114 and 208 and the information that would be relevant to the EPA's carrying out a wide variety of CAA provisions when considering source categories. As part of the process in selecting the original list of source

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[147] See, *e.g.,* Comments by Carbon Utilization Research Council, Clean Air Task Force, ClearPath, Environmental Defense Fund, Oxy Low Carbon Ventures, Shell Oil Company, and The Nature Conservancy on the Proposed "Credit for Carbon Oxide Sequestration," Docket Id. No. IRS–2020–0013–0057, August 3, 2020; Comments by Clean Air Task Force on the Proposed "Credit for Carbon Oxide Sequestration," Docket Id. No. IRS–2020–0013–0035, August 3, 2020; Comments by Shell Oil Company on the Proposed "Credit for Carbon Oxide Sequestration," Docket Id. No. IRS–2020–0013–0046, August 4, 2020. These comments are in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

categories to include in the GHG Reporting Rule in 2010, the EPA considered the language of the Appropriations Act, which referred to reporting ''in all sectors of the economy,'' and the accompanying explanatory statement, which directed the EPA to include ''emissions from upstream production and downstream sources to the extent the Administrator deems it appropriate'' (74 FR 16465, April 10, 2009). To develop the list of source categories, we followed a four-step process: (1) we first considered all anthropogenic sources of GHG emissions or supply; (2) we considered all of the source categories in the U.S. GHG Inventory; (3) we reviewed the 2006 IPCC Guidelines for National Greenhouse Gas Inventories for source categories that may be relevant for the United States; and (4) once the list was completed, we systematically reviewed those source categories to ensure that they included the most significant sources of GHG emissions and the most significant suppliers of GHG-emitting products. We also confirmed that the reported GHGs can be measured with an appropriate level of accuracy.[148] As described in sections IV.A through F of this preamble, we are requesting comment on expanding existing source categories or developing other new source categories based on the EPA's current understanding of U.S. GHG trends and where we have identified that additional data may be necessary to better understand GHG data from these specific sectors to inform future policy.

The addition of these source categories would provide data that would help eliminate data gaps, improve the coverage of the GHGRP, and inform the development of GHG policies and programs under the CAA. The GHGRP data continues to additionally be used as a resource for the U.S. GHG Inventory, providing not only annual emissions information, but also other annual information such as activity data and emission factors that can improve and refine national emission estimates and trends over time. Including these additional source categories would also allow the EPA to gather data that could improve the completeness of the emissions estimates presented in the U.S. GHG Inventory. For example, we are requesting comment on whether the EPA should collect data on energy consumption, a source category for which part 98 does not currently require reporting and which would support data analyses related to informing voluntary energy efficiency programs, providing information on industrial sectors where currently little data is reported to GHGRP, and informing QA/QC of the U.S. GHG Inventory. Inclusion of certain of these source categories would reduce potential data gaps in the GHGRP by incorporating emission sources that are recommended by (and for which there are existing calculation methodologies available in) the 2006 IPCC Guidelines used to prepare the U.S. GHG Inventory. Specifically, the IPCC 2006 Guidelines currently identify ceramics production, calcium carbide production, and glyoxal, glyoxylic acid, and caprolactam production as potential sources of GHG emissions. However, emissions from these processes are not currently estimated in the GHGRP or the U.S. GHG Inventory. The collection of data from these source categories (*e.g.,* ceramic production, calcium carbide production, and glyoxal, glyoxylic acid, and caprolactam production) would improve the coverage of the GHGRP and provide for more accurate estimates of U.S. GHG emissions that could then be used to inform development of EPA policies and programs.

The EPA is requesting comment on some source categories, such as coke calciners, that we have identified because they may potentially contribute significant emissions that are not currently reported. In other cases, through implementation of the program, the EPA has identified facilities representative of these source categories that are currently reporting under another part 98 source category, and relying on that other source category's calculation, monitoring, and reporting requirements for the purposes of estimating total facility GHG emissions. However, these facilities may not in fact be reporting complete or accurate estimates of emissions because appropriate estimation methods are currently unavailable for the source category. We are also requesting comment on source categories where we have identified emerging industries that utilize captured carbon emissions, and as a result would improve our knowledge of carbon utilization.

Inclusion of specific requirements for these source categories in part 98 would provide a means for the EPA to better estimate and understand U.S. GHG emissions and trends that could inform future policies. Therefore, we are soliciting comment on these source categories and the appropriate accounting methodologies, monitoring, and associated reporting requirements that should be considered in development of a future proposed rulemaking. Sections IV.A through IV.F of this preamble provide additional information on the EPA's consideration of including these source categories in the GHGRP and the information we are seeking.

The EPA is also considering proposing future amendments to subpart F of part 98 (Aluminum Production) to include reporting for additional sources of emissions, to update the cell technology types reflected in the rule, and to revise or replace the measurement and calculation methodologies with newer, improved methodologies. These updates are being considered based on new information and methodologies identified from the *2019 Refinement.* Section IV.G of this preamble provides additional information on the EPA's consideration of these amendments and the information we are seeking.

A. Energy Consumption

Indirect GHG emissions can result from on-site energy consumption, primarily the use of purchased electricity and thermal energy products. In this preamble we refer broadly to purchased electricity and thermal energy products such as steam, heat (in the form of hot water), and cooling (in the form of chilled water) as ''purchased energy'' or as ''purchased energy products.'' These terms expressly exclude the purchase of fuels associated with direct emissions.

In the 2009 GHGRP proposal, the EPA sought comment on, but did not propose, reporting related to electricity consumption. See 74 FR 16479, April 10, 2009. Comments received, as well as our responses to those comments, are summarized in the 2009 final rule. See 74 FR 56288–56289, October 30, 2009. We note that in 2009 some commenters expressed concerns regarding the collection of data on purchased electricity for several reasons. Primarily, they said it would constitute double counting if direct emissions were collected from electric utilities and the EPA also collected electricity consumption from facilities and estimated emissions attributable to the facilities' electricity consumption. Others stated that collecting information on electricity purchases was outside the scope of the rule, that it is not useful information in attempting to quantify emissions, that it would be burdensome for facilities, and that it is CBI that companies are not able to share with the EPA. In 2009, we responded to these concerns stating that collection of electricity purchase data under the GHGRP is consistent with the

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[148] Refer to the preamble to the April 10, 2009 proposal (74 FR 16465) for further discussion of the EPA's rationale for its original section of source categories to include.

Consolidated Appropriations language,[149] and provides valuable information to the EPA and stakeholders in the development of climate change policy and programs. We still believe this to be true today. Ultimately, the EPA decided at that time not to propose requirements for facilities to report either their electricity purchases or indirect emissions from electricity consumption. In the 2009 final rulemaking, we stated that acquiring such data may be important in the future, and we were exploring options for possible future data collection on electricity purchases and indirect emissions and the uses of such data. We also said that such a future data collection on indirect emissions would complement the EPA's interests in energy efficiency and renewable energy.

In this action, we are requesting comment on whether the EPA should expand the GHGRP so that facilities that are subject to the GHGRP would be required to submit new, summary data elements quantifying their consumption of purchased energy products and characterizing associated markets and products (*e.g.,* regulated or de-regulated electricity markets and renewable attributes of purchased products). Under this approach, facilities would not be required to quantify indirect emissions, and indirect emissions would not count towards GHGRP applicability. However, the EPA could estimate indirect emissions using the purchased energy data. We solicit comment on this potential approach and on advantages and disadvantages of limiting the scope of any new reporting requirements to compiling and reporting purchased energy records.

The EPA is seeking comment on how an energy consumption source category should be defined, whether it should include purchased thermal energy products, and whether or not associated reporting requirements should differentiate purchased thermal energy products from purchased electricity.

The EPA also seeks comment on the approach of limiting applicability of an energy consumption source category to facilities that are currently subject to the GHGRP. For example, should the EPA consider adding new sector-specific requirements for operators of EAFs or other operations that may meet all their energy needs with purchased power and that may not trigger applicability under the GHGRP? The EPA is seeking comment on specific industrial sectors or technologies that may not be completely represented within the GHGRP but that should be considered when evaluating the performance of GHGRP sources (including usage of purchased energy) within discrete sectors.

The EPA also seeks comment on measures that would minimize the burden of reporting parameters related to purchased energy transactions. The EPA understands that cogeneration contracts between host facilities and energy producers are governed by clear metering and billing requirements. Accordingly, the EPA is seeking comment on our understanding that monitoring and recordkeeping systems are already in place for purchased energy transactions, and the incremental reporting burden would be minimal. We are also seeking comment on existing industry standards for assessing the accuracy of the monitoring systems used for purchased energy transactions.

B. Ceramics Production

The ceramics manufacturing industry comprises a variety of products manufactured from nonmetallic, inorganic materials, many of which are clay-based. The major sectors of ceramic products include bricks and roof tiles, wall and floor tiles, table and ornamental ware, 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 general process of manufacturing ceramic products consists of raw material processing (grinding, calcining, and drying), forming, firing, and final processing (which may include grinding, polishing, surface coating, annealing, and/or chemical treatment).

GHG emissions are produced during the calcination process in the kiln or dryer and from any combustion sources. According to the IPCC 2006 Guidelines,[150] CO_2 emissions result from the calcination of the raw material (particularly clay, shale, limestone, dolomite, and witherite) and the use of limestone as a flux. Carbonates are heated to high temperatures in a kiln or dryer, producing oxides and CO_2. Additionally, CO_2, CH_4, and N_2O emissions are produced during combustion in the kiln or dryer and from other combustion sources on site.

The EPA is considering future amendments to the GHGRP to add a source category related to ceramics production or to incorporate ceramics into an existing subpart. Currently, under the GHGRP, ceramic production facilities report their GHG emissions from stationary fuel combustion sources if those emissions exceed the 25,000 mtCO$_2$e reporting threshold. Some ceramic production facilities should also report miscellaneous uses of carbonate if they meet applicability requirements of subpart U of part 98 (Miscellaneous Uses of Carbonate).[151] Addition of a ceramics production source category would likely include process emissions and would improve the EPA's understanding of facility-level emissions from this source category by adding to the completeness of the data collected under the GHGRP, and better inform future EPA policy. Additionally, such data would be available to inform estimates and improve completeness of the U.S. GHG Inventory, consistent with methodological guidance and completeness principle outlined in the 2006 IPCC guidelines.

According to the 2018 United States Census Bureau, 815 corporations produce ceramic products;[152] however, only sixteen facilities owned by nine of these corporations reported under subpart C of the GHGRP (General Stationary Fuel Combustion Sources) for RY2019. No ceramics manufacturers currently report under subpart U of part 98. While some ceramics manufacturers may use some carbonates directly, it is likely the majority of the carbonates used are those contained in clay rather than pure carbonates. Additionally, some ceramic tile kilns may not heat to temperatures sufficient for calcination to occur, and therefore would not meet the applicability requirements of subpart U. For these reasons, emissions from ceramics manufacturers may not be appropriately captured by the current part 98. Although the nine corporations reported nearly 1 million mtCO$_2$e from combustion under subpart C for RY2019, we estimate, using United States Geological Survey (USGS) reports[153] on the tons of clays sold or

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[149] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. Congress reaffirmed interest in a GHG Reporting Rule, and provided additional funding, in the 2009 Appropriations Act (Consolidated Appropriations Act, 2009, Pub. L. 110–329, 122 Stat. 3574–3716).

[150] 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.*

[151] Subpart U of part 98 includes any equipment that uses the carbonates limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate and emits CO_2. Facilities are considered to emit CO_2 if they consume at least 2,000 tons per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

[152] See U.S. Census Bureau website (*https://www.census.gov/naics/*), accessed March 2021.

[153] USGS 2020 Mineral Commodity Summaries. Clay. U.S. Department of the Interior, U.S. Geological Survey, February 2020. *https://*

used in the United States and IPCC default emission factor values, that the total process CO_2 emissions from carbonates for all ceramic production facilities in the United States is an additional 1.16 million $mtCO_2e$. We are considering whether adding a ceramic production source category, as a separate source category or combined with either the existing subpart N of part 98 or subpart U of part 98, would provide a more accurate estimation methodology for these emissions.

Methods for calculating GHG emissions from ceramic production are available in the 2006 IPCC Guidelines,[154] including methods based on: (1) default emission factors that assume limestone and dolomite are the only carbonates contained in clay and that 85 percent of carbonates consumed are limestone and 15 percent of carbonates consumed are dolomite; (2) facility-specific data on the quantity of limestone versus dolomite consumed; and (3) a carbonate input approach that accounts for all carbonates (species and amounts) and which mirrors the methodology used for estimating CO_2 emissions from glass production in subpart N of part 98. We are considering whether emissions could be estimated for the ceramics production source category by modifying these methodologies to consider facility-specific inputs. Facilities could potentially also use a CEMS to monitor CO_2 emissions from the kiln or dryer and use the CEMS data to report GHG emissions. More information about these potential methods can be found in the document, *Technical Support Document for Ceramics: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

The EPA seeks comment on whether it should add a source category related to ceramics production, and if so, seeks information that could be related to source category definitions, calculation methodologies, and reporting requirements. For example, we are soliciting comment on how the source category should be defined, and whether it should be included as a separate category or as part of an existing category, either subpart N (Glass Production) or subpart U (Miscellaneous Uses of Carbonate). We also seek comment on which IPCC calculation methodologies or other methodologies, including those listed in the document, *Technical Support Document for Ceramics: Proposed Rule for the Greenhouse Gas Reporting Program,* should be used, with consideration of what information is readily available to reporters. Finally, we are requesting input on available monitoring methodologies or quality assurance requirements that should be used, including what data is readily available for reporting that would help to support emissions estimates.

C. Calcium Carbide Production

Calcium carbide (CaC_2) is used in production of acetylene (for cutting and welding) and calcium cyanamide (for industrial agricultural fertilizers). CaC_2 is manufactured from lime and carbon-containing raw materials (usually petroleum coke), by heating the mixture to approximately 2,000 degrees Celsius in an EAF. Use of carbon-containing raw materials in the production process results in CO_2 and CO emissions. In addition, any presence of hydrogen-containing volatile compounds and sulfur in the carbon-containing raw materials may cause formation of CH_4 and SO_2 emissions. Also, production of acetylene from CaC_2 results in CO_2 emissions.

The EPA is considering future amendments to the GHGRP to add a source category related to CaC_2 production (which may potentially also include acetylene production if a facility produces acetylene at their CaC_2 production facility). The IPCC 2006 Guidelines currently identify both silicon carbide production and calcium carbide production as potential sources of GHG emissions.[155] Although the GHGRP currently accounts for emissions from silicon carbide production processes, and the GHGRP collects data from silicon carbide production under subpart BB, emissions from CaC_2 production are not explicitly accounted for. Addition of a CaC_2 production source category to the GHGRP would better align with intergovernmental approaches to estimating emissions, improve the completeness of the data collected under the GHGRP, add to the EPA's understanding of the GHG data, and better inform future EPA policy. Further, such data would be available to improve the estimates provided in the U.S. GHG Inventory, by improving completeness and comparability of the estimates consistent with the 2006 IPCC guidelines.

The EPA has identified a CaC_2 production facility currently operating in the United States that is voluntarily reporting GHG emissions under subpart K (Ferroalloy Production) of part 98. Annual emissions from the reporting facility range between less than 10,000 and 50,000 $mtCO_2e$. We are considering whether adding the calcium carbide source category, either as a separate source category or combined with the existing silicon carbide production category under subpart BB of part 98, would provide more accurate applicability requirements and emissions estimation methodologies for these types of facilities. We are also considering, where acetylene production from CaC_2 occurs at the same facility, whether we should account for emissions from these sources.

We are considering several options for how emissions could be estimated for CaC_2 production at a facility-level based on methods available in the 2006 IPCC Guidelines, including methods based on: (1) default emission factors applied to activity data on petroleum coke consumption or CaC_2 production; (2) a carbon consumption methodology that assumes a stoichiometric conversion where two-thirds of the carbon consumed is in the CaC_2 product and one-third is emitted as CO_2 (similar to the estimation methods used for the silicon carbide production source category in subpart BB); and (3) a carbon balance method that uses measured quantities of carbon consumed in the process and carbon contained in the CaC_2 product. Facilities could potentially also estimate CO_2 emissions using CEMS. More information about these potential methods and the production of CaC_2 can be found in the document, *Technical Support Document for Calcium Carbide: Proposed Rule for the Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

The EPA seeks comment on whether it should add a source category related to CaC_2 production, and if so, seeks information related to source category definitions, calculation methodologies, and reporting requirements. For example, we solicit comment on how the source category should be defined, and whether it should be included as a separate category or, due to similarity in estimation methods, as part of the existing silicon carbide production category. We also request comment on whether additional CaC_2 production facilities (other than Carbide Industries

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www.usgs.gov/centers/nmic/mineral-commodity-summaries.

[154] 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.*

[155] 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.*

LLC in Louisville, KY) are currently operating in the United States. In addition, we seek comment on which tier calculation methodology as well as the monitoring or measurement methodologies should be used, particularly the methodology(s) for which facilities would have information readily available. Furthermore, we seek comment on whether any CaC_2 production facility currently operating in the United States uses the CaC_2 product to produce acetylene at the same facility, and whether emissions from acetylene production should be accounted for in the emission estimate methodology. Finally, we seek input on available monitoring methodologies that should be used, as well as input on what data are readily available for reporting that would help to support emissions estimates.

D. Glyoxal, Glyoxylic Acid, and Caprolactam Production

Glyoxal ($C_2H_2O_2$) is used in a variety of applications 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; as a chemical intermediate in the production of pharmaceuticals, dyestuffs, glyoxylic acid, and other chemicals; and to improve moisture resistance in wood treatment. Glyoxal is also being used as a less toxic substitute for formaldehyde in some applications such as wood adhesives and embalming fluids. Glyoxal is commercially manufactured by either: (1) the gas-phase catalytic oxidation of ethylene glycol with air in the presence of a silver or copper catalyst (the LaPorte process); or (2) the liquid-phase oxidation of acetaldehyde with nitric acid. Glyoxylic acid ($C_2H_2O_3$) is used mainly in the synthesis of vanillin, allantoin, and several antibiotics like amoxicillin, ampicillin, and the fungicide azoxystrobin. Glyoxylic acid is exclusively produced by the oxidation of glyoxal with nitric acid. Caprolactam ($C_6H_{11}NO$) is a monomer used in carpet manufacturing. The addition of hydroxylamine sulphate to cyclohexanone produces cyclohexanone oxime, which can then be converted to caprolactam.

The production of any of these organic compounds (glyoxal, glyoxylic acid, and caprolactam) results in N_2O and CO_2 emissions. N_2O emissions are created from either oxidation or reduction steps that occur in each process. Our knowledge of the mechanisms that generate CO_2 emissions from glyoxal and glyoxylic acid production is less understood. The IPCC 2006 Guidelines state that CO_2 emissions generated from caprolactam production are unlikely to be significant in well-managed plants.[156]

The EPA is considering future amendments to the GHGRP to add a source category related to glyoxal, glyoxylic acid, and caprolactam production to improve the completeness of the data collected under the GHGRP, add to the EPA's understanding of the GHG data and better inform future EPA policy. Emissions from these processes are not currently estimated in U.S. GHG Inventory. Therefore, once collected, such data would be available to and improve on the estimates provided in the U.S. GHG Inventory, by incorporating the recommendations of the 2006 IPCC guidelines, which currently identify glyoxal, glyoxylic acid, and caprolactam production as potential sources of GHG emissions.[157] Grouping these three organic compounds together into one source category for GHGRP purposes would be reasonable because the 2006 IPCC guidelines methodology for estimating GHG emissions from the production of these compounds does the same.[158]

We are unsure whether there are any glyoxal and/or glyoxylic acid production facilities currently operating in the United States. Based on available 2015 data reported under the Toxic Substances Control Act (TSCA), four facilities could be domestic manufacturers of glyoxal.[159] [160] Also, although four facilities reported glyoxylic acid data under the TSCA, each of these facilities reported no domestically manufactured glyoxylic acid. We note that more recent data for 2016 through 2019 are expected to be published by the TSCA, but these data were not available at the time of writing this proposal. Nevertheless, it is possible that there are other glyoxal and glyoxylic acid production facilities operating in the United States, but that are not reporting under the TSCA because their total production volume is less than 25,000 pounds per year, or they are exempt from reporting because they are a small manufacturer based on their total company sales revenue. Currently, two caprolactam production facilities report GHG emissions under subpart C of part 98 (General Stationary Fuel Combustion Sources) (each facility reported RY2019 combustion emissions of approximately 600,000 to 800,000 $mtCO_2e$).

Methods for calculating N_2O emissions from glyoxal, glyoxylic acid, and caprolactam production are available in the 2006 IPCC Guidelines, including methods based on: (1) total nationwide production quantities using default uncontrolled emission factors; (2) plant-specific production quantities using plant-specific or default N_2O generation and control emission factors; and (3) plant-specific production quantities and direct measurement of emissions to calculate plant-specific emission factors.[161] Although the 2006 IPCC Guidelines do not provide methods for calculating CO_2 emissions from glyoxal and glyoxylic acid production,[162] we are considering use of either a default emission factor approach for N_2O and a mass balance approach for CO_2, or development of site-specific factors for both N_2O and CO_2. In the first approach, N_2O emissions would be calculated using production and the IPCC default factors, and for CO_2, the mass balance procedures would be similar to mass balances required for existing subparts in the GHGRP such as petrochemical production (subpart X). Specifically, site-specific quantities of all carbon-containing feedstocks and products would be determined, and CO_2 emissions would be calculated assuming all carbon from the feedstock that does not end up in product is emitted as CO_2. We recognize that if the N_2O is controlled using something other than thermal or catalytic destruction (that would not convert hydrocarbons to CO_2), then this mass balance approach would not work for CO_2. Alternatively, N_2O and CO_2 emissions could be calculated using site-specific production and site-specific emission factors that are developed based on flow measurement and periodic sampling and compositional analysis of the

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

[157] *Id.*

[158] *Id.*

[159] ChemView. Compilation of data submitted under TSCA in 2012 and 2016. *https://chemview.epa.gov/chemview.* Accessed April 2021.

[160] In 2015, four facilities indicated that their glyoxal production status (*i.e.,* as a domestic manufacturer or as an importer) and their quantities domestically manufactured and/or imported, were CBI. Thus, it is possible that one or more of these four glyoxal production facilities could be a domestic manufacturer.

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

[162] As previously mentioned, the 2006 IPCC Guidelines, CO_2 emissions generated from $C_6H_{11}NO$ production are likely to be insignificant.

streams to the control and exiting the control. These emission factors would be multiplied by the site-specific production quantity to calculate emissions. More information about these N_2O and CO_2 emission calculation methods and the production of glyoxal, glyoxylic acid, and caprolactam can be found in the document, *Technical Support Document for Glyoxal, Glyoxylic Acid, and Caprolactum Production: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

The EPA seeks comment on whether it should add a source category related to glyoxal, glyoxylic acid, and caprolactam production, and if so, seeks information that could be related to source category definitions, calculation methodologies, and reporting requirements. For example, we solicit comment on how the source category should be defined. In addition, as previously mentioned, although we are aware of at least two caprolactam production facilities, we are unsure whether there any glyoxal and/or glyoxylic acid production facilities currently operating in the U.S.; therefore, we seek information about whether these types of facilities are currently operating in the U.S. We request comment on whether facilities have installed abatement equipment. We also solicit comment on which tier calculation methodologies or other methodologies, including those outlined in the document *Technical Support Document for Glyoxal, Glyoxylic Acid, and Caprolactum Production: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424), should be used to determine GHG emissions from these types of facilities and which information or inputs for these methodologies is readily available. Furthermore, as previously mentioned, although we are considering a mass balance approach to determine CO_2 emissions from these types of facilities, our knowledge of the mechanisms that generate CO_2 emissions from glyoxal and glyoxylic acid production are not fully understood; therefore, we request information on this subject. Finally, we seek input on available monitoring methodologies and quality assurance procedures that should be used; and input on what data are readily available for reporting that would help to support emissions estimates.

E. Coke Calcining

Calcined petroleum coke is a nearly pure carbon material used primarily to make anodes for the aluminum, steel, and titanium smelting industries. The process used to produce calcined petroleum coke is called coke calcination and is commonly performed in coke calciners that are rotary kilns or rotary furnaces equipped with an afterburner. Coke calcining uses ‘‘green’’ petroleum coke with low metals content (commonly called ‘‘anode grade petroleum coke’’) as a feed material. The coke is then heated to high temperatures in the absence of air or oxygen for the purpose of removing impurities or volatile substances in the green coke. Auxiliary fuel is needed to start-up the kiln or furnace, but once the desired calcining temperature is reached, process gas consisting of volatile organics and sulfur-containing compounds driven from the coke are used as the primary fuel to maintain calciner temperatures. Similarly, the coke calciner afterburner combusts primarily the process off-gas and requires little, if any, auxiliary fuel except during start-up. The afterburner is used to convert excess process gas to CO_2 and SO_2, and a waste heat boiler may be used to recover energy from this combustion process. The afterburner will also likely release trace amounts of CH_4 and N_2O, similarly to other stationary combustion devices. The afterburner off-gas is emitted to the atmosphere and is the primary source of GHG emissions from this process.

Coke calcining processes may be co-located with petroleum refineries or may be independent facilities. Currently, coke calcining processes co-located at petroleum refineries must calculate and report emissions from coke calciners following the methodologies specified in subpart Y of part 98 (Petroleum Refineries). Several coke calciners not co-located at petroleum refineries report emissions that are calculated using the calculation methodologies under subpart C of part 98 (General Stationary Fuel Combustion Sources). The calculation methodologies in subparts C and Y, for facilities not using CEMS, are substantially different, resulting in inconsistent characterization of emissions between the two populations of sources. Specifically, the subpart C emission calculations assume that the carbon content of the fuel burned is represented by the default carbon content of petroleum coke and that the carbon in the petroleum coke is fully combusted and converted to CO_2 whereas the subpart Y calculation uses a mass balance approach to account for the fact that the carbon content in the final product is higher than the carbon content in the petroleum coke fed to the unit, thereby more accurately accounting for the carbon content in the process gas actually combusted. The EPA is considering future amendments to the GHGRP to add a coke calcining source category to require specific calculation methodologies and reporting requirements for coke calciners not co-located with petroleum refineries, in order to improve the completeness of the data collected under the GHGRP and better inform future EPA policy. Incorporating a new source category would improve the consistency of emission calculation methodologies for coke calcining processes units regardless of whether nor not they are co-located with a petroleum refinery. The EPA seeks comment on whether a separate source category for coke calcining facilities should be added to the GHGRP.

The EPA identified 15 coke calcining facilities operating 29 coke calcining process units in the United States. Most coke calcining facilities are located at or near a petroleum refinery. Three of the facilities report GHG emission under subpart Y. The remaining facilities either do not report coke calcining emissions or report emissions under subpart C. Based on data reported to the GHGRP for RY2019, the typical coke calcining facility emits 150,000 $mtCO_2e$ per year. With 15 operating facilities in the U.S., it is estimated that these facilities emit 2.2 million $mtCO_2e$ per year. The EPA seeks information on the total number of facilities currently operating coke calciners in the United States.

There are four possible calculation methodologies for determining GHG emissions from coke calciners, shown in order of most accurate to least: (1) use of CEMS; (2) a mass balance using the carbon content of the green and calcined coke; (3) a mass balance using a fixed methane content in the coke and using a mass reduction in the quantity of coke fed to the process and the quantity of coke leaving the process; and (4) using either default high heat values and CO_2 emission factors or assuming the reduction in the mass of coke is solely due to the combustion of green coke fed to the calciner. More information about these methods and the coke calcining process can be found in the memorandum, *Technical Support Document for Coke Calcining: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424).

Subpart Y allows the use of CEMS (methodology (1), as noted above). If CEMS are not used, subpart Y requires the use of a carbon mass balance approach using equation Y–13 (methodology (2), as noted above). Facilities using equation Y–13 must measure the mass of petroleum coke in and out of the process and the carbon content of the coke in and out of the process. Subpart Y also requires estimating CH_4 and N_2O emissions based on the CO_2 emissions, and the ratio of the CH_4 or N_2O emission factor for ''petroleum products'' in Table C–2 of subpart C and the CO_2 emission factor for petroleum coke in Table C–1 of subpart C of part 98. If a new subpart for coke calcining is developed, the EPA seeks comment on the appropriate calculation method(s) to require. The EPA is also seeking comment on whether coke calcining facilities are already collecting the necessary information to estimate GHG emissions using methodologies (2), (3), and (4), as described in this section. We are also seeking comment on appropriate monitoring for the four methodologies described in the *Technical Support Document for Coke Calcining: Proposed Rule for The Greenhouse Gas Reporting Program,* available in the docket for this rulemaking (Docket Id. No EPA–HQ–OAR–2019–0424). Finally, we are seeking input on appropriate missing data and quality assurance procedures.

F. CO_2 Utilization

As mentioned in the previous section, CCUS refers to a set of technologies that capture CO_2 from the emissions of large point sources or ambient air, transport it, compress it, and either utilize it or inject it in deep underground for safe and secure storage. CO_2 utilization is a quickly growing area of interest among stakeholders and there is currently a lack of publicly available and nationally consistent GHG data regarding CO_2 utilization. As technologies scale up and markets develop for CO_2 utilization, the potential for GHG mitigation through CO_2 utilization is expected to greatly expand. There are a broad range of CO_2 utilization pathways (*i.e.,* technological approaches for carbon utilization), with each utilization pathway having its own set of specific characteristics in terms of products manufactured, technical maturity, market potential, economics, potential to displace existing products or sources of CO_2, and lifecycle GHG impact.

The EPA is considering amendments to part 98 to add a source category related to CO_2 utilization. While part 98 has source categories related to Suppliers of Carbon Dioxide (subpart PP), Injection of Carbon Dioxide (subpart UU) and Geologic Sequestration of Carbon Dioxide (subpart RR), it does not have a source category that is solely related to CO_2 utilization. The inclusion of CO_2 utilization as a source category in part 98 could fill a critical informational gap and inform future policy and programs under the CAA.

The EPA seeks comment on whether we should add a source category related to CO_2 utilization, and if so, seeks information related to source category definition; calculation, monitoring and QA/QC methodologies; and reporting requirements.

The EPA seeks comment on how the source category would be defined. In order to define the source category, the EPA seeks information to contextualize potential reporters and understand how this reporting would relate to other source categories of the GHGRP. For example, the EPA seeks comment on different types of end products that utilize CO_2 (currently and potentially), the amount of captured CO_2 used per unit of production or manufacture (gallons, metric tons, etc.) for different processes (currently and potentially), including processes that do not result in manufacture of marketable product (*e.g., ex-situ* mineralization for storage only). Additionally, the EPA seeks comment on the total amount of captured CO_2 being used in the end use per year for different manufacturing processes or utilization pathways (currently and potentially),[163] whether there should be a threshold for reporting, and if so, how that threshold should be defined. The EPA seeks information on the total number of facilities (currently and potentially), and how many facilities would be reporting under different potential thresholds. The EPA requests comment on whether particular CO_2 utilization pathways should be included in the source category, and if so, how should those pathways be defined. The EPA also requests comment on whether the source category should include reporting of not only CO_2, but also other greenhouse gases.

The EPA seeks comment on what calculation methodologies should be used for purposes of part 98 reporting. For example, most source categories reporting under part 98 focus on reporting of direct emissions. Taking a similar approach for CO_2 utilization would exclude emissions associated with the end use of the CO_2 in the product. A full accounting of all GHGs from cradle to grave, including the potential to displace an existing product or other existing source of CO_2, would be needed to understand the product's life cycle and total GHGs emitted. To that end, the EPA seeks input regarding whether a GHG LCA should be required, and if so, what information, protocols, guidance, and/or models would be required to conduct the LCA, who should validate it, what information would need to be reported to support the LCA validation, and to what extent LCA information is already reported through other GHGRP subparts.

In addition to calculation methodologies, the EPA seeks comment on what monitoring requirements should be in place and what methodologies are recommended for monitoring and QA/QC. LCA is also relevant with regard to monitoring, as CO_2 can be stored and emitted at various stages of the product's lifecycle, and the length of CO_2 storage varies between CO_2 utilization pathways and end products. The EPA also seeks comment on how permanence of the CO_2 storage should be defined and addressed if LCA were not required. Similarly, the EPA seeks comment on information that could be used for, and the feasibility of developing, sequestration lifetimes for various products that result from different utilization pathways. For both calculation and monitoring of CO_2 utilization under part 98 reporting, the EPA seeks comment on QA/QC practices to ensure consistent and accurate estimates.

Finally, the EPA requests comment on the reporting requirements related to CO_2 utilization. CO_2 utilization technologies can vary widely (*e.g.,* biological, chemical, or physical processes), and many technologies are still emerging. The EPA seeks input on how to manage reporting of these highly variable and emerging technologies. For example, we are seeking comment on whether different technology categories should have different calculation, monitoring, and reporting requirements. Additionally, the EPA requests comment regarding specific data elements to be reported. This includes the amount of CO_2 utilized, types of greenhouse gases to be reported (*i.e.,* reporting of not only CO_2, but also other greenhouse gases), and end uses of the CO_2. It also includes emissions of greenhouse gases throughout the lifecycle of a product, and more specifically emissions of greenhouse gases during the utilization process, the ultimate fate of the CO_2 used, and the

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[163] The EPA notes that aggregated totals of primary end uses for CO_2 captured and produced are available on the GHGRP website at *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

sequestration lifetime of the utilized CO_2. EPA also seeks comment on whether the source of CO_2 used in the utilization process should be reported, and if so, what information on the source should be reported (*e.g.,* captured versus extracted, sector or type of facility from which the CO_2 was captured and sourced, and/or facility-specific information for where CO_2 was captured and sourced).

G. Aluminum Production

The EPA is considering proposing to amend subpart F of part 98 (Aluminum Production) to add reporting of low voltage emissions and cell-start-up emissions. The EPA is also considering updating cell technology categories to be consistent with the *2019 Refinement.* The EPA is also considering updating or replacing the 2008 Protocol [164] (used for development of the current emissions measurement methodology) based on the 2020 International Aluminium Institute (IAI) ''Good Practice Guidance: Measuring Perfluorocarbons'' [165] (hereafter referred to as ''2020 IAI Good Practice Guidance'') and the 2008 U.S. EPA/IAI ''Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production'' [166] developed by the IAI. Low voltage anode effects (LVAEs), where the cell voltage does exceed the voltage threshold, have been identified as a source of CF_4 emissions and can be a significant portion of the emissions in modern high-amperage cells with many large anodes. Emissions from LVAEs would be better characterized by measuring emission factors specifically for low voltage emissions. Emissions of CF_4 from LVAEs have not previously been included due to a lack of data and methodology for their estimation. However, the *2019 Refinement* provides several methods for estimating LVAE emissions. The *2019 Refinement* also provides methods for potentially more accurately characterizing cell start-up emissions and high voltage anode effect emissions (HVAEs) through the addition of new non-linear Tier 3 methods. The 2020 IAI Good Practice Guidance provides additional guidance on measurement frequency, calculation of emission factors using new Tier 3 calculation methods available in the *2019 Refinement* and updating methods to account for both low voltage and high voltage emissions of PFCs. In addition to improving the accuracy of emissions reported the GHGRP and adding to the EPA's understanding of facility-level emissions from this source category, the collection of low voltage and start-up emissions data would also improve emissions estimates for the U.S. GHG Inventory and better inform future EPA policy. Currently the U.S. GHG Inventory uses a Tier 1 emission factor to estimate LVAE emissions, based on production technology and high voltage emission estimates, which may overestimate low voltage emissions. However, the LVAE data is still somewhat limited. Additional studies would help to assess how frequently measurements must be made to maintain an accurate accounting of smelter emissions, including low voltage emissions. Studies are also needed to assess the relative advantages in robustness and accuracy of the non-linear method for calculating HVAE PFC emissions. The EPA requests comment on the extent to which low voltage emissions have been characterized and if data is available to develop guidance on low voltage emission measurements needed to develop robust LVAE emission factors. The EPA also requests comment 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 is also requesting comment on the methods and protocols in the 2020 IAI Good Practice Guidance.

V. Schedule for the Proposed Amendments

The EPA is planning to consider the comments on these proposed changes, and, if any of the proposed amendments are finalized, to respond to the comments and publish any amendments before the end of 2022. We are proposing that these amendments would become effective on January 1, 2023 and that reporters would implement the changes beginning with reports prepared for RY2023 and submitted April 1, 2024.

We have determined that it would be feasible for existing reporters to implement the proposed changes for RY2023 because the revisions primarily include improvements to the rule that are consistent with the current data collection and calculation methodologies. Some of the proposed amendments would clarify and improve the existing rule in order to enhance the quality and accuracy of the data collected. These revisions primarily provide additional clarifications or flexibility regarding the existing regulatory requirements, do not add new monitoring or sampling requirements, and do not substantially affect the information that must be collected (*i.e.,* require new data collection). In the limited cases where we are proposing to require the collection of additional data, such as from subpart W (Petroleum and Natural Gas Systems) facilities, we are proposing to allow reporters to use BAMM for the first annual report submitted for RY2023 (as discussed in section III.J of this preamble), which would provide additional time for facilities to adapt to new monitoring requirements and, for example, install the appropriate equipment. Where calculation equations are proposed to be modified, the changes clarify equation terms or simplify the calculations, and do not require any additional data monitoring. In these cases, we anticipate that facilities would have any additional inputs for calculations available in company records or could easily calculate the required input from existing process knowledge and engineering estimates, or from available company records. Therefore, these types of changes are not anticipated to add significant burden for reporters. Although we are proposing one change to require additional reporting under subpart C (for separate reporting of biogenic emissions from the combustion of tires), because we are simultaneously proposing removal of the ''less than 10 percent'' restriction on using the default biogenic CO_2 factor to estimate biogenic emissions in 40 CFR 98.33(e)(3)(iv), the new reporting would not require any additional monitoring or data collection. As such, all reporters who combust tires would be able to use the default biogenic CO_2 factor, and would not need to conduct quarterly flue-gas testing, to establish the biogenic fraction of emissions.

In several instances we are proposing to require reporting of additional data elements to improve verification of annual reports, provide a more complete picture of GHG emissions or supply, or develop factors that may inform the U.S. GHG Inventory. As provided in section III of this preamble, in these instances we anticipate that the data is already available in company records (*e.g.,* production or material use data, or data on product or equipment type). In most

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[164] U.S. Environmental Protection Agency & International Aluminium Institute. (2008). Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production. Available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[165] Available at *https://international-aluminium.org/resource/good-practice-guidance-measuring-perfluorocarbons/* and in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

[166] Available at *https://international-aluminium.org/resource/good-practice-guidance-measuring-perfluorocarbons/* and in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

cases the data we are requesting can be calculated using data that is already required to be entered into the EPA's reporting system, is already maintained in keeping with existing facility data permits (*e.g.,* hours of operation an abatement device was not in use), or may be estimated using emission factors or engineering judgment. For example, where we are proposing to add reporting of unit specific data for subpart C (General Stationary Fuel Combustion Sources) reporters using the aggregation of units or common pipe configurations, facilities already collect data on the maximum rated heat input capacity of individual units in each aggregation of units or common pipe configuration (greater than or equal to 10 mmBtu/hr) to determine the reported cumulative maximum rated heat input capacity, and would be able to determine the other data elements requested (*i.e.,* unit type and estimate of the fraction of annual heat input) from their existing company records.

Additionally, although we are proposing the addition of calculation and reporting requirements under new subpart VV (Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916), we do not anticipate that the new subpart would expand the existing coverage of facilities subject to the GHGRP, but would only apply to those reporters that currently report under subpart UU (Injection of Carbon Dioxide) and that choose to report amounts of CO_2 stored under the proposed subpart VV. It is anticipated that these facilities already follow the calculation requirements and data gathering prescribed under CSA/ANSI ISO 27916:2019 (*e.g.,* as discussed in section III.W of this preamble, to quantify storage for the IRC section 45Q tax credit); would not perform any additional calculation, monitoring, or quality assurance procedures under the proposed requirements; and that the information submitted to the GHGRP would be obtained and provided from readily available data. These facilities will also retain the option to continue to report under existing subpart UU with no changes. Therefore, we have determined that it would be feasible for facilities who opt to report under proposed subpart VV to implement the proposed changes for RY2023.

Other proposed changes streamline and improve implementation by simplifying or clarifying calculation, monitoring, and recordkeeping, or reporting. These types of changes are intended to simplify or provide flexibility in the requirements that reporters must meet and do not require additional data collection. For these reasons, we believe that a proposed effective date of January 1, 2023 is reasonable. Reporters are not required to submit RY2023 reports until April 1, 2024, which is over a year after we expect a final rule based on this proposal to be finalized, if finalized, thus providing an opportunity for reporters to adjust to any finalized amendments. The proposed effective date would also allow ample time for the EPA to implement the changes into e-GGRT.

We are proposing one change that would impact the date of submittal of a non-annual report. For subpart I, we are proposing to revise the frequency of submittal of the technology assessment reports required under 40 CFR 98.96(y). The proposed change would revise the frequency of submittal from three years to five years. Under the current rule, semiconductor manufacturing facilities are required to submit their next technology assessment report by March 31, 2023 (concurrent with their RY2022 annual report). The proposed change would affect the due date of the following technology assessment report, moving the due date from March 31, 2023 to March 31, 2025. Because the proposed change would decrease the frequency of submissions and extend the timeframe for reporters to collect and compile data for the next submittal, we have determined that the proposed changes would be feasible to implement by this date.

We are likewise proposing that the proposed CBI determinations discussed in section VI of this preamble would become effective on January 1, 2023. The majority of the determinations are for new or revised data elements that would be included in annual GHG reports prepared for RY2023 and submitted April 1, 2024. However, there are some circumstances, discussed in detail in section VI of this preamble, where the proposed determinations cover data included in annual GHG reports submitted for prior years. In either case, the proposed determinations for the data that the EPA has already received for these prior years or receives going forward for any reporting year would become effective on January 1, 2023.

VI. Proposed Confidentiality Determinations for Certain Data Elements

A. Overview and Background

Part 98 requires reporting of numerous data elements to characterize, quantify, and verify GHG emissions and related information. Following proposal of part 98 (74 FR 16448, April 10, 2009), the EPA received comments addressing the issue of whether certain data could be entitled to confidential treatment. In response to these comments, the EPA stated in the preamble to the 2009 Final Rule (74 FR 56387, October 30, 2009), that through a notice and comment process, we would establish those data elements that are entitled to confidential treatment. This proposal is one of a series of rulemakings dealing with confidentiality determinations for data reported under part 98. For more information on previous confidentiality determinations for part 98 data elements, see the following documents:

- 75 FR 39094, July 7, 2010. Describes the data categories and category-based determinations the EPA developed for the part 98 data elements.
- 76 FR 30782, May 26, 2011; hereafter referred to as the ''2011 Final CBI Rule.'' Assigned data elements to data categories and published the final CBI determinations for the data elements in 34 part 98 subparts, except for those data elements that were assigned to the ''Inputs to Emission Equations'' data category.
- 77 FR 48072, August 13, 2012. Finalized confidentiality determinations for data elements reported under nine subparts I, W, DD, QQ, RR, SS, UU; except for those data elements that are inputs to emission equations. Also finalized confidentiality determinations for new data elements added to subparts II and TT in the November 29, 2011 Technical Corrections document (76 FR 73886).
- 78 FR 68162; November 13, 2013. Finalized confidentiality determinations for new data elements added to subpart I.
- 78 FR 69337, November 29, 2013. Finalized determinations for new and revised data elements in 15 subparts, except for those data elements assigned to the ''Inputs to Emission Equations'' data category.
- 79 FR 63750, October 24, 2014. Revised recordkeeping and reporting requirements for ''inputs to emission equations'' for 23 subparts and finalized confidentiality determinations for new data elements in 11 subparts.
- 79 FR 70352, November 25, 2014. Finalized confidentiality determinations for new and substantially revised data elements in subpart W.
- 79 FR 73750, December 11, 2014. Finalized confidentiality determinations for certain reporting requirements in subpart L.
- 80 FR 64262, October 22, 2015. Finalized confidentiality determinations for new data elements in subpart W.
- 81 FR 86490, November 30, 2016. Finalized confidentiality determinations

for new or substantially revised data elements in subpart W.

- 81 FR 89188, December 9, 2016. Finalized confidentiality determinations for new or substantially revised data elements in 18 subparts and for certain existing data elements in 4 subparts.

In this document, we are proposing confidentiality determinations or ''emission data'' designations for:

- New or substantially revised reporting requirements (*i.e.,* the proposed change requires additional or different data to be reported);
- Existing reporting requirements for which the EPA did not previously finalize a confidentiality determination or ''emission data'' designation; and
- Existing reporting requirements for which the EPA is proposing to amend existing confidentiality determinations. This includes cases where the EPA is proposing to amend confidentiality determinations to align with determinations established in 40 CFR part 84 under the American Innovation and Manufacturing Act of 2020 (AIM Act).

We are also aware that a few confidentiality determinations finalized in a previous rulemaking were not clear, and we are now clarifying the previous determinations. Further, we propose to designate certain new or substantially revised data elements as ''inputs to emission equations'' falling within the definition of ''emission data'' (see section VI.C of this preamble for a discussion of ''inputs to emission equations''), and we are proposing to require reporting of those data elements. Table 5 of this preamble provides the number of affected data elements and the affected subparts for each of these proposed actions.

Table 5 of this preamble also describes the effective date of these proposed actions. The majority of the determinations would apply at the same time as the proposed schedule described in section V of this preamble. In the cases where the EPA is proposing a determination for existing data elements where one was not previously made, or where the EPA is clarifying an existing determination, the proposed determination would be effective on January 1, 2023 for RY2023 as well as all prior years that the data was collected. For the data elements where we are proposing to amend previous determinations to align with rulemakings establishing 40 CFR part 84 under the AIM Act, the proposed confidentiality determinations would apply only prospectively, starting with RY2022 for the reasons described in section VI.D of this preamble.

TABLE 5—SUMMARY OF PROPOSED ACTIONS RELATED TO DATA CONFIDENTIALITY

Proposed actions related to data confidentiality	Number of data elements [a]	Subparts	Effective year
New or substantially revised reporting requirements for which the EPA is proposing a confidentiality determination or “emission data” designation.	283	C, G, H, I, N, P, Q, S, W, X, Y, BB, DD, GG, HH, OO, PP, SS, VV.	RY2023.
Existing reporting requirements for which the EPA is proposing a confidentiality determination or “emission data” designation because the EPA did not previously make a confidentiality determination or “emission data” designation.	33	A, I, K, W, HH	RY2023, and all prior years the data was collected.
Existing reporting requirements for which the EPA is proposing to amend an existing confidentiality determination.	33	A, RR, UU	RY2023.
Existing reporting requirements for which the EPA is clarifying the current confidentiality determination.	12	A, L, MM, NN	RY2023, and all prior years the data was collected.
New or substantially revised reporting requirements that the EPA is proposing be designated as “inputs to emission equations” and for which the EPA is proposing reporting determinations.	125	C, I, W, DD, SS	RY2023.
Existing reporting requirements for which the EPA is proposing to amend an existing confidentiality determination to align with determinations under the AIM Act.	9	OO	RY2022.

[a] These data elements are listed in the memoranda: (1) *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* (2) *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 (3) *Proposed Determinations that would Align the Greenhouse Gas Reporting Program with the Determinations Made under the AIM Act Regulations,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424).

Finally, we are confirming that, except for the cases discussed in detail in this proposal, part 98 data elements previously determined to be entitled to confidential treatment through rulemaking will continue to be treated as such under the standard for confidentiality set forth in *Food Marketing Institute* v. *Argus Leader Media,* 139 S. Ct. 2356 (2019).

B. Proposed Confidentiality Determinations and Emissions Data Designations

1. Proposed Approach

The EPA's past approach for evaluating reporting requirements for confidentiality was established in the 2011 Final CBI Rule (76 FR 30782, May 26, 2011). This approach was based on the requirements of 40 CFR part 2, which included an assessment of whether disclosure of the data would cause a likelihood of substantial competitive harm. As set forth in the 2011 Final CBI Rule, the EPA categorized all reporting requirements into 22 data categories and reviewed them for confidentiality as follows:

- 12 data categories were established and designated as either ''CBI'' or ''not CBI'' (hereafter referred to as ''categorical confidentiality determinations''), and all data elements assigned to one of these 12 data categories were also assigned the confidentiality determination of ''CBI'' or ''not CBI'' for that category;
- 5 data categories were established that were not assigned any categorical confidentiality determinations; instead, for each data element in these categories, the EPA made individual determinations through rulemaking for each data element;
- 4 data categories were established and designated as ''emission data'' (as defined in 40 CFR 2.301(a)(2)(i)) and all data elements assigned to these four data categories were assigned a categorical designation of ''emission data,'' which under CAA section 114 are not entitled to confidential treatment;[167] therefore, no data assigned to these four categories were further evaluated for confidentiality; and
- 1 data category, ''Inputs to Emission Equations,'' was proposed on July 7, 2010 (75 FR 39094) to be ''emissions data.'' Evaluation of data elements assigned to this data category was first conducted in the October 24, 2014 final rule (79 FR 63750). Refer to section VI.C of this preamble for further discussion of the EPA's evaluation and treatment of data assigned to the ''Inputs to Emission Equations'' data category.

Since the 2011 Final CBI Rule, we have followed the approach outlined above in all rulemakings for evaluating reporting requirements for confidentiality. However, in this document we are proposing to revise our approach to assessing data for confidentiality in response to *Food Marketing Institute* v. *Argus Leader Media,* 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*).[168] In *Argus Leader,* the U.S. Supreme Court issued an opinion addressing the meaning of the word ''confidential'' in Exemption 4 of the Freedom of Information Act, 5 U.S.C. Section 552(b)(4)(2012 and Supp. V. 2017) stating that ''confidential'' must be given its ''ordinary'' meaning, which is information that is ''private'' or ''secret.'' As a result, starting with the date of the *Argus Leader* ruling, the EPA no longer assesses data elements using the rationale of whether disclosure will cause a likelihood of substantial competitive harm when making confidentiality determinations. Instead, the EPA assesses whether the information is customarily and actually treated as private by the reporter and whether the EPA has given an assurance at the time the information was submitted that the information will be kept confidential or not confidential.

We are proposing that the *Argus Leader* decision does not impact 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.'' For a discussion of the EPA's rationale for why the *Argus Leader* decision does not impact our previous approach for handling ''inputs to emission equations,'' refer to section VI.C of this preamble. The *Argus Leader* decision does not apply to data elements designated as ''emission data,'' because section 114(c) of the CAA precludes ''emission data'' from being considered confidential and requires that such data be available to the public. Therefore, the *Argus Leader* decision does not impact our previous approach for designating new and revised reporting requirements as ''emission data.'' We propose 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 to meet the CAA definition of ''emission data'' in 40 CFR 2.301(a)(2)(i) [169] (hereafter referred to as ''emission data categories''). As discussed in section II.B of the July 7, 2010 proposal (75 FR 39100), the four emission data categories include the following categories of data reported by direct emitters (*i.e.,* ''emission data'' does not apply to suppliers reporting under the GHGRP as discussed in section II.C.2 of the preamble for the 2011 Final CBI Rule (76 FR 30782, May 26, 2011)):

- Category 1: Facility and Unit Identifier Information;
- Category 2: Emissions;
- Category 3: Calculation Methodology and Methodological Tier; and
- Category 4: Data Elements Reported for Periods of Missing Data that are Not Inputs to Emission Equations.

Refer to section II.B of the July 7, 2010 proposal for descriptions of each of these data categories and the EPA's rationale for designating each data category as ''emission data.'' Note that the proposed ''emission data'' designations discussed in section VI.B.2 of this preamble involve assignment to only the first three emission data categories in the bulleted list above (*i.e.,* we are not proposing that any reported elements be assigned to the ''Data Elements Reported for Periods of Missing Data that are Not Inputs to Emission Equations'' data category).

For reporting elements that the EPA does not designate as ''emission data'' or ''inputs to emission equations,'' the EPA is proposing a revised approach for assessing data confidentiality. We propose to assess each individual reporting element according to the *Argus Leader* criteria (*i.e.,* whether the information is customarily and actually treated as private by the reporter); therefore, we are not proposing to assign the data elements to *any* data category established by the 2011 Final CBI Rule. Refer to section VI.B.2 of this preamble for further discussion of the EPA's evaluation of data elements according to the *Argus Leader* criteria and proposed confidentiality determinations.

2. Proposed Confidentiality Determinations and ''Emission Data'' Designations

In this section, we discuss the proposed confidentiality determinations

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[167] See section I.C of the preamble for the July 7, 2010 CBI proposal (75 FR 39094, July 7, 2010) for further discussion of CAA section 114 requirements. The term ''emission data'' is defined at 40 CFR 2.301(a)(2)(i).

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

[169] See section I.C of the July 7, 2010 proposal (75 FR 39100) for a discussion of the definition of ''emission data.'' As discussed therein, the relevant paragraphs (to the GHGRP) of the CAA definition of ''emission data'' include 40 CFR 2.301(a)(2)(i)(A) and (C), as follows: (A) ''Information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source (or of any pollutant resulting from any emission by the source), or any combination of the foregoing;'' and (C) ''A general description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources (including, to the extent necessary for such purposes, a description of the device, installation, or operation constituting the source).''

and ''emission data'' designations for: (1) 283 new or substantially revised data elements, (2) 33 existing data elements (*i.e.,* not proposed to be substantially revised) for which we have not previously finalized a confidentiality determination or ''emission data'' designation, and (3) 33 existing data elements for which we are amending an existing confidentiality determination. We are also clarifying 12 previous confidentiality determinations, as discussed in section VI.B.2.d of this preamble.

Further, we are confirming that, except for the specific situations discussed in sections VI.B.2.c and VI.D of this preamble, the data elements previously determined to be entitled to confidential treatment in the following rulemakings will continue to be treated as such under the new confidentiality standard set forth in *Argus Leader:*

- 2011 Final CBI Rule;
- 77 FR 48072, August 13, 2012;
- 78 FR 68162; November 13, 2013;
- 78 FR 69337, November 29, 2013;
- 79 FR 63750, October 24, 2014;
- 79 FR 70352, November 25, 2014;
- 79 FR 73750, December 11, 2014;
- 80 FR 64262, October 22, 2015;
- 81 FR 86490, November 30, 2016; and
- 81 FR 89188, December 9, 2016.

a. Proposed Confidentiality Determinations and ''Emission Data'' Designations for New or Substantially Revised Data Reporting Elements

For the 283 new and substantially revised data elements, the EPA is proposing ''emission data'' designations for 90 data elements and confidentiality determinations for 193 data elements. The EPA is proposing to designate 90 new or substantially revised data elements as ''emission data'' by assigning the data elements to three emission data categories (established in the 2011 Final CBI Rule as discussed in section VI.B.1 of this preamble), as follows:

- 44 data elements that are proposed to be reported under subparts G, P, S, W, and VV are proposed to be assigned to the ''Emissions'' emission data category;
- 25 data elements that are proposed to be reported under subparts C, Q, and W are proposed to be assigned to the ''Facility and Unit Identifier Information'' emission data category; and
- 21 data elements that are proposed to be reported under subparts I, W, and SS are proposed to be assigned to the ''Calculation Methodology and Methodological Tier'' emission data category.

Refer to Table 1 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of these 88 specific data elements proposed to be designated as ''emission data,'' the proposed emission data category assignments for each data element, and the EPA's rationales for the proposed emission data category assignments.

The remaining 193 new and substantially revised data elements not proposed to be designated as ''emission data,'' or ''inputs to emission equations,'' are proposed to be reported under subparts H, N, Q, S, W, X, Y, BB, DD, GG, HH, OO, PP, SS, and VV. This proposal assesses each individual reporting element according to the *Argus Leader* criteria as discussed in section VI.B.1 of this preamble. Refer to Table 2 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* to see a list of these 193 specific data elements with this status receiving a determination, the proposed confidentiality determination for each data element, and the EPA's rationales for the proposed confidentiality determinations.

b. Proposed Confidentiality Determinations and ''Emission Data'' Designations for Existing Part 98 Data Reporting Elements for Which No Determination Has Been Previously Established

We are also proposing confidentiality determinations and ''emission data'' designations for 33 data elements currently in subparts A, I, K, W, and HH for which no confidentiality determination or ''emission data'' designation has been previously finalized under part 98. We reviewed previous rulemakings and found the following instances where a confidentiality determination or ''emission data'' designation had not been made:

- For subparts A, K, and HH, three data elements were added in the 2009 Final Rule following public comment. The EPA did not make confidentiality determinations in that rulemaking and has not finalized determinations for these data elements in subsequent rulemakings.
- Also for subpart A, one data element was added in the August 13, 2012 rulemaking (77 FR 48072) following public comment. The EPA did not make a confidentiality determination in that rulemaking and has not finalized a determination for the data element in a subsequent rulemaking.
- For subpart I, one data element was added in the final rulemaking published on August 13, 2012 (77 FR 48072), and one data element was revised in the final rulemaking published on November 13, 2013 (78 FR 68162). For the data element added on August 13, 2012, the EPA had not proposed a confidentiality determination and, therefore, did not finalize a determination in the final rule. For the data element revised on November 13, 2013, the EPA retained a previous decision for the previous version of the data element not to assign a confidentiality determination to the data element (see the final rulemaking on August 13, 2012, 77 FR 48072). Since the EPA did not evaluate either data element for confidentiality in those two rulemakings or in subsequent rulemakings, the EPA has not previously finalized a confidentiality determination for the data element.
- Also for subpart A, one data element was added in the final rulemaking published on December 11, 2014 (79 FR 73750) following public comment. The EPA had not proposed a confidentiality determination or ''emission data'' designation for the data element and therefore did not finalize confidentiality determinations in the final rule.
- For Subpart W, 21 data elements were added or substantially revised in the final rulemaking published on November 25, 2014 (79 FR 70352) following public comment. Additionally, 5 data elements were added in the final rulemaking published on October 22, 2015 (80 FR 64242) following public comment. The EPA had not proposed a confidentiality determination or ''emission data'' designation for these new or revised data elements, and therefore did not finalize confidentiality determinations in the final rules.

Of these 33 data elements, we propose to designate 26 data elements as ''emission data'' and therefore they would not be entitled to confidential treatment by assigning the data elements to three emission data categories (established in the 2011 Final CBI Rule as discussed in section VI.B.1 of this preamble), as follows:

- 11 data elements in subparts A and W are proposed to be assigned to the ''Emissions'' emission data category;
- 14 data elements in subparts A and W are proposed to be assigned to the

''Facility and Unit Identifier Information'' emission data category; and

- 1 data element in subpart I is proposed to be assigned to the ''Calculation Methodology and Methodological Tier'' emission data category.

Refer to Table 3 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of these 26 specific data elements proposed to be designated as ''emission data'', the proposed emission data category assignment for each data element, and the EPA's rationale for the proposed emission data category assignments.

For the remaining 7 existing reported data elements in subparts A, I, K, W, and HH for which no confidentiality determination or ''emission data'' designation has been previously finalized under part 98, we propose to assess each individual data element according to the *Argus Leader* criteria as discussed in section VI.B.1 of this preamble. Refer to Table 4 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule* (available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of each of these seven specific data elements with this status receiving a determination, the proposed confidentiality determination for each data element, and the EPA's rationales for the proposed confidentiality determinations.

c. Proposed Confidentiality Determinations for Existing Part 98 Data Reporting Elements for Which a Previous Determination Is Proposed To Be Amended

We are proposing to amend the confidentiality determinations previously finalized under part 98 for five existing data elements in subpart A, 16 data elements in subpart RR, and 12 data elements in subpart UU. In amending the confidentiality determinations, we propose to evaluate each individual data element according to the *Argus Leader* criteria as discussed in section VI.B.1 of this preamble. Three of these data elements from subpart A (40 CFR 98.3(c)(5)(ii)(A) through (C)) were added to subpart A in the December 9, 2016 rulemaking (81 FR 89188). The EPA finalized confidentiality determinations for these three data elements in that rule. We are now proposing to amend those finalized confidentiality determinations from ''emissions data'' to ''not CBI'' for the data reported by suppliers under subpart OO. We are amending the previous determinations, because no data reported by suppliers meet the definition of ''emission data'' for the purposes of the GHGRP.[170] Two more data elements from subpart A (40 CFR 98.3(c)(5)(ii)) for both subparts LL and MM) were added to subpart A in the 2009 Final Rule. The EPA finalized confidentiality determinations for the data elements in the 2011 Final CBI Rule (76 FR 30782). We are proposing to amend the existing determinations because those determinations did not take into account situations where the data may already be publicly available.

With respect to subparts RR and UU, we are proposing to amend the confidentiality determinations for 16 data elements in subpart RR where previously no categorical CBI determinations were made and for 12 data elements in subpart UU where the EPA previously determined the data elements to be CBI. More specifically, we are proposing to change the confidentiality determinations for the 16 Subpart RR and 12 subpart UU data elements to ''Not CBI'' consistent with the *Argus Leader* criteria.

Subpart RR and UU reporters must report the quantities of CO_2 received at the custody transfer meter. Subpart RR reporters must also report the quantities of CO_2 produced at the separator flow meter if they are actively producing oil or natural gas or any other fluids. The EPA originally proposed that the quantities of CO_2 received and CO_2 produced including the mass and volumetric flow and CO_2 concentrations used to calculate these values would not be CBI (77 FR 1434, January 10, 2012). Following review of public comment, however, the EPA in its final rulemaking (77 FR 48072, August 13, 2012) determined that the quantities of CO_2 received and CO_2 produced could contain sensitive information for some facilities that report under subparts RR and UU, thus presenting the potential for competitive harm to the submitter if the information was released. At the time, the EPA was not aware that this information could be found publicly. The EPA, therefore, made categorical determinations of ''CBI'' for the 12 subpart UU data elements and did not make categorical determinations for the 16 subpart RR data elements.

We have revisited the original confidentiality determinations for these data elements under the *Argus Leader* standard and have determined that the EPA's original basis for the confidentiality determinations is not valid. The EPA has now determined that company and facility-level data for CO_2 received and CO_2 produced are often available to the public through company websites and annual reports, company filings with the Securities and Exchange Commission, presentations at conferences and other events, and third-party analyses. In addition, oil and gas production to the well level is reported to state oil and gas commissions and is widely available to the public through the commission websites and records as well as through third parties. General rules-of-thumb for the quantity of CO_2 required to produce a barrel of oil are often used in the oil and gas industry to estimate CO_2 quantities received and injected. Since the EPA has now found that this information is largely publicly available, we are determining in the proposed rule that the quantities of CO_2 received and CO_2 produced submitted under subparts RR and UU cannot be entitled to confidential treatment under the standard set forth by the *Argus Leader* decision.

Refer to Table 5 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424) for a list of each of the 33 data elements with this status receiving a determination, the proposed confidentiality determination for each data element, and the Agency's rationale for each proposed determination.

d. Clarification of Previous Confidentiality Determinations

We are clarifying the confidentiality determinations previously finalized under 40 CFR part 98 for 12 data elements currently in subparts A, LL (Suppliers of Coal-based Liquid Fuels), MM (Suppliers of Petroleum Productions), and NN. These 12 data elements were added in the 2009 Final Rule, and confidentiality determinations were finalized in the 2011 Final CBI Rule (76 FR 30782). For these 12 data elements, there were discrepancies regarding the finalized confidentiality determinations in the 2011 Final CBI Rule (76 FR 30782) between the confidentiality determination specified in the preamble to the final rule and the

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[170] See section II.C.2 of the preamble for the 2011 Final CBI Rule (76 FR 30782, May 26, 2011) for further discussion of the EPA's determination that the supplier data elements do not meet the definition of emission data.

confidentiality determination specified in the April 29, 2011 memorandum to the rulemaking.[171] We are clarifying which explanation of the Agency's confidentiality determination for each of the 12 data elements was correct, and we are providing explanations for the discrepancies between the determination specified in the preamble to the final rule and the supporting memorandum. These clarifications do not change the EPA's treatment of these 12 data elements; the confidentiality determinations being clarified are consistent with how the EPA has treated these reported data since promulgation of the May 26, 2011 final rule. This clarification will be effective for all previous and future reporting years. However, due to the conflict in the previous rules, we are providing a new opportunity to comment on the Agency's treatment of these data. Refer to Table 6 in the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424), for a list of the 12 data elements with this status, the clarified confidentiality determinations for each data element, and an explanation of the discrepancy in the documentation of their confidentiality determinations.

C. Proposed Reporting Determinations for Inputs to Emission Equations

As discussed in section I.C of the preamble to the October 24, 2014 rule (79 FR 63750), the EPA organizes data assigned to the ''Inputs to Emission Equations'' data category into two subcategories. The first subcategory includes ''inputs to emission equations'' entered into e-GGRT's Inputs Verification Tool (IVT). These ''inputs to emission equations'' are entered into IVT to satisfy the EPA's verification requirements. These data must be maintained as records by the submitter, but the data are not included in the annual report that is submitted to the EPA. This is done in circumstances where the EPA has determined that the ''inputs to emission equations'' meet the criteria necessary for them to be entered into the IVT system. The second subcategory includes ''inputs to emission equations'' that must be included in the annual report submitted to the EPA. This is done in circumstances where the EPA has determined that the data elements assigned to the ''Inputs to Emission Equations'' category do not meet the criteria necessary for them to be entered into the IVT system. These ''inputs to emission equations,'' once received by the EPA, are not held as confidential.

As stated in section VI.B.1 of this preamble, the EPA is determining that the *Argus Leader* decision does not impact our approach for handling of data elements assigned to the ''Inputs to Emission Equations'' data category. Data assigned to this data category and subcategorized by the Agency as ''inputs to emission equations'' entered into IVT do not become federal records for the purposes of part 98 reporting, so no confidentiality determination needs to be made for data elements determined to fall within this subcategory of data. Since this subcategory of data is only entered into the IVT system and not in the annual report sent directly to the EPA, the *Argus Leader* decision does not affect the approach to these data or the criteria the Agency uses to determine whether these data should be considered to fall within this subcategory. Likewise, for the same reason, the *Argus Leader* decision does not impact actions in previous rulemakings designating certain data as ''inputs to emission equations'' to be entered into the IVT system.

In continuation of this past approach, we are proposing to assign 125 new or substantially revised data elements in subparts I, W, DD, and SS to the ''Inputs to Emission Equations'' data category. Based on our evaluation of each data element assigned to the ''Inputs to Emission Equations'' data category, we determined that none of these 125 evaluated data meet the criteria necessary for them to be entered into the IVT system; therefore, we propose that all 125 of these data elements be reported to the EPA and would be considered ''emission data.'' These ''inputs to emission equations'' once received by the EPA would not qualify to be held as confidential. Refer to Table 1 in the memorandum, *Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Revisions to the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket Id. No. EPA–HQ–OAR–2019–0424) for a list of the 125 data elements proposed to be reported that are being designated as ''inputs to emission equations,'' and the EPA's rationale for the proposed reporting determinations. The table also includes a discussion of the criteria that we established in 2011 for evaluating whether data assigned to the ''Inputs to Emission Equations'' data category should be entered into the IVT system. In our evaluation we found that even if the 2011 criteria were based on the standard for confidential treatment set forth in the Supreme Court's 2019 *Argus Leader* decision, it would not impact our determination that these 125 data elements should be directly reported to EPA instead of entered into IVT.

Note that this proposal also includes proposed revisions to calculation methodologies in direct emitter subparts G, P, S, and Y that would require reporters under these subparts to enter new or substantially revised ''inputs to emission equations'' in IVT. These new and substantially revised data elements are not proposed to be included in the reporting section of those subparts but would instead be retained as records. Since the EPA is not proposing to include these data in the annual report, the data elements are not included in the evaluation discussed in this section. Refer to section III of this preamble for discussion of all proposed revisions to the recordkeeping sections of subparts G, P, S, and Y.

D. Proposed Revision to Confidentiality Determinations for Existing 40 CFR Part 98 Data Elements Affected by the AIM Implementation Rule

On October 5, 2021, the EPA finalized the AIM Implementation Rule (86 FR 55116), which establishes a program to phase down hydrofluorocarbon production and consumption (hereafter referred to as the ''AIM Act'') at 40 CFR part 84 (hereafter referred to as ''Part 84''). There are cases where similar or identical data will be collected under both the AIM Act under Part 84 and the GHGRP under part 98. For some of these overlapping data, the EPA had previously determined under part 98 that the data would be treated as confidential when collected under the GHGRP. However, pursuant to the AIM Act, the EPA subsequently determined that the overlapping data elements collected under the AIM Act would not be provided confidential treatment. Refer to section X.C of the AIM Implementation Rule for the Agency's rationale for these determinations (86 FR 55191). Specifically, the AIM Implementation Rule determined that 12 data elements would not be eligible for confidential treatment when reported under the AIM Act where the data had previously been determined to be entitled to confidential treatment under the GHGRP.

To align the GHGRP with the AIM Act, we are proposing to amend the confidentiality determinations made

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[171] See April 29, 2011 memorandum ''Final Data Category Assignments and Confidentiality Determinations for Part 98 Reporting Elements,'' available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

under the GHGRP for these 12 overlapping data elements. As these 12 data elements are not eligible for confidential treatment and will be publicly released under the AIM Act, there is no basis for treating the data as confidential under the GHGRP. Therefore, we are proposing that the data no longer be entitled to confidential treatment when reported under the GHGRP. We are proposing to amend the confidentiality determinations for these 12 overlapping data elements for only those reporting years that the data are collected under the AIM Act and only those GHGs covered by the AIM Act. First, regarding the reporting years, the EPA has been collecting many of these 12 data elements under the GHGRP since 2010, whereas the EPA will only begin collecting data under the AIM Act for activities beginning in 2022. Therefore, we are not proposing to amend the confidentiality determinations for any years prior to 2022 that the data were collected under the GHGRP. Instead, we propose to amend the part 98 confidentiality determinations prospectively, such that these 12 data elements would not be treated as confidential for the annual reports covering RY2022 and future years. Second, regarding GHGs, the AIM Act requires reporting of 18 GHGs, whereas the GHGRP covers a much broader set of GHGs. We are proposing to amend the part 98 confidentiality determinations for these 12 data elements only for reported data associated with the exact GHGs covered under the AIM Act as listed in appendix A of part 84.

The 12 overlapping data elements for which we are proposing to amend the confidentiality determination include data elements currently reported under subparts A and OO of part 98. A list of these 12 affected data elements and the proposed determinations are specifically listed in Table 1 in the memorandum titled *Proposed Determinations that would Align the Greenhouse Gas Reporting Program with the Determinations Made under the AIM Act Regulations* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

The AIM Implementation Rule also included one HFC data element to be used in the administration of the AIM Act that is only reported under part 98 but not under the AIM Act, specifically under 40 CFR 98.416(a). This data element is ‘‘Annual quantities of fluorinated greenhouse gases [other than HFCs regulated under the AIM Act], identified by type, intentionally produced on a facility line that also produces HFC-23.’’[172] The Agency will invoke the modification provisions of 40 CFR 2.301(d)(4) to make an individual determination on this specific data element. Once that process is completed, the Agency may make a conforming change to the confidentiality determination for that data category in the final version of this rulemaking. Note that the determination affects only fluorinated greenhouse gases that are produced on a facility line that also produces HFC–23.

E. Request for Comments on Proposed Category Assignments, Confidentiality Determinations, or Reporting Determinations

By proposing confidentiality determinations prior to data reporting through this proposal and rulemaking process, we provide potential reporters an opportunity to submit comments, particularly comments identifying data elements proposed by the Agency to be ‘‘not CBI’’ that reporters consider to be customarily and actually treated as private. Likewise, we provide potential reporters an opportunity to submit comments on whether there are disclosure concerns for ‘‘inputs to emission equations’’ that we propose would be included in the annual reports and subsequently released by the EPA. This opportunity to submit comments is intended to provide reporters with the opportunity that is afforded to reporters when the EPA considers claims for confidential treatment of information in case-by-case confidentiality determinations under 40 CFR part 2. In addition, the comment period provides an opportunity to respond to the EPA's proposed determinations with more information for the Agency to consider prior to finalization. We will evaluate the comments on our proposed determinations, including claims of confidentiality and information substantiating such claims, before finalizing the confidentiality determinations. Please note that this will be reporters' only opportunity to substantiate a confidentiality claim for data elements included in this rulemaking where a confidentiality determination or reporting determination is being proposed. Upon finalizing the confidentiality determinations and reporting determinations of the data elements identified in this proposed rule, the EPA will release or withhold these data in accordance with 40 CFR 2.301(d), which contains special provisions governing the treatment of part 98 data for which confidentiality determinations have been made through rulemaking pursuant to CAA sections 114 and 307(d).

If members of the public have reason to believe any data elements in this proposed rule that are proposed to be treated as confidential are not customarily and actually treated as private by reporters, please provide comment explaining why the Agency should not provide an assurance of confidential treatment for data.

When submitting comments regarding the confidentiality determinations or reporting determinations we are proposing in this action, please identify each individual proposed new, revised, or existing data element you consider to be confidential or do not consider to be ‘‘emission data’’ in your comments. If the data element has been designated as ‘‘emission data,’’ please explain why you do not believe the information should be considered ‘‘emission data’’ as defined in 40 CFR 2.301(a)(2)(i). If the data has not been designated as ‘‘emission data’’ and is proposed to be not entitled to confidential treatment, please explain specifically how the data element is commercial or financial information that is both customarily and actually treated as private. Particularly describe the measures currently taken to keep the data confidential and how that information has been customarily treated by your company and/or business sector in the past. This explanation is based on the requirements for confidential treatment set forth in *Argus Leader.* If the data element has been designated as an ‘‘input to an emission equation’’ (*i.e.,* not entitled to confidential treatment), please explain specifically why there are disclosure concerns.

Please also discuss how this data element may be different from or similar to data that are already publicly available, including data already collected and published annually by the GHGRP, as applicable. Please submit information identifying any publicly available sources of information containing the specific data elements in question. Data that are already available through other sources would likely be found not to qualify for confidential treatment. In your comments, please identify the manner and location in which each specific data element you identify is publicly available, including a citation. If the data are physically published, such as in a book, industry trade publication, or federal agency publication, provide the title, volume number (if applicable), author(s),

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[172] See pg. 12 of ‘‘Memorandum—Classification of Data Reported Under the HFC Phasedown Rule’’ available at Docket Id. No. EPA–HQ–OAR–2021–0044–0227 and in the docket to for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

publisher, publication date, and International Standard Book Number (ISBN) or other identifier. For data published on a website, provide the address of the website, the date you last visited the website and identify the website publisher and content author. Please avoid conclusory and unsubstantiated statements, or general assertions regarding the confidential nature of the information.

Finally, we are not proposing new confidentiality determinations and reporting determinations for data reporting elements proposed to be unchanged or minimally revised because the final confidentiality determinations and reporting determinations that the EPA made in previous rules for these unchanged or minimally revised data elements are unaffected by this proposed amendment and will continue to apply. The minimally revised data elements are those where we are proposing revisions that would not require additional or different data to be reported. For example, under subpart FF, we are proposing to revise a data element to clarify the term ''Mine Safety and Health Administration (MSHA) number'' to be ''Mine Safety and Health Administration (MSHA) identification number'' (see 40 CFR 98.246(t)). This proposed change would not impact the data collected, and therefore we are not proposing a new or revised confidentiality determination. However, we are soliciting comment on any cases where a minor revision would impact the previous confidentiality determination or reporting determination. In your comments, please identify the specific data element, including name and citation, and explain why the minor revision would impact the previous confidentiality determination or reporting determination.

VII. Impacts of the Proposed Amendments

The EPA is proposing amendments to part 98 in order to implement improvements to the GHGRP, including revisions to update existing emission factors and emissions estimation methodologies, revisions to require reporting of additional data to understand new source categories or new emission sources for specific sectors and address potential gaps in reporting, and revisions to collect data that would improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates, verification of collected data, or to complement or inform other EPA programs. The EPA is also proposing revisions that would improve implementation of the program, such as those that would update applicability estimation methodologies, provide flexibility for or simplifying calculation and monitoring methodologies, streamline recordkeeping and reporting, and other minor technical corrections or clarifications identified as a result of working with the affected sources during rule implementation and outreach. The EPA anticipates that the proposed revisions would result in an overall increase in burden for reporters. The proposed revisions would increase burden in cases where the proposed amendments add or revise reporting requirements or require additional emissions data to be reported. We anticipate a decrease in burden where the proposed revisions would 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 proposing changes where we anticipate increased clarity or more flexibility for reporters that could result in a potential decrease in burden, but we are unable to quantify this decrease.

As discussed in section V of this preamble, we are proposing to implement these changes for RY2023 reports. Costs have been estimated over the three years following the year of implementation. The incremental implementation costs for all subparts for each reporting year are summarized in Table 6 of this preamble. The estimated annual average labor burden is $1,417,494 per year. The incremental burden by subpart is shown in Table 6 of this preamble.

TABLE 6—TOTAL INCREMENTAL LABOR BURDEN FOR REPORTING YEARS 2023–2025

[$2017/year]

Cost summary	RY2023	RY2024	RY2025	Annual average
Burden by Year (all subparts)	$1,417,591	$1,416,802	$1,418,090	$1,417,494

There is an additional annual incremental burden of $7,281 for capital and operation and maintenance (O&M) costs, which reflects changes to applicability and monitoring for subparts I, P, W, UU, and VV. Including capital and O&M costs, the total annual average burden is $1,424,775 over the next 3 years.

The incremental burden by subpart is shown in Table 7 of this preamble. Note that subparts with proposed revisions that would not result in any changes to burden (*e.g.,* subparts FF and NN) are excluded from this table.

TABLE 7—TOTAL INCREMENTAL BURDEN BY SUBPART

[$2017/year] [a]

Subpart	Labor costs		Capital and O&M
	Initial year	Subsequent years	
C—General Stationary Fuel Combustion Sources			
Facilities Reporting only to Subpart C	$70,732	$70,732	
Facilities Reporting to Subpart C plus another subpart	94,999	94,999	
G—Ammonia Manufacturing	250	250	
H—Cement Production	3,655	3,655	
I—Electronics Manufacturing [b]	19,056	17,839	$50

TABLE 7—TOTAL INCREMENTAL BURDEN BY SUBPART—Continued

[$2017/year][a]

Subpart	Labor costs		Capital and O&M
	Initial year	Subsequent years	
N—Glass Production	818	818	
P—Hydrogen Production	628	628	(1,536)
Q—Iron and Steel Production	1,454	1,454	
S—Lime Manufacturing	1,351	1,351	
W—Petroleum and Natural Gas Systems	1,211,076	1,211,076	8,667
X—Petrochemical Production	528	528	
Y—Petroleum Refineries	801	801	
BB—Silicon Carbide Production	20	20	
DD—Electrical Equipment Use	7,106	7,106	
GG—Zinc Production	20	20	
HH—Municipal Solid Waste Landfills	3,297	3,297	
OO—Suppliers of Industrial Greenhouse Gases	810	810	
PP—Suppliers of Carbon Dioxide	629	629	
SS—Electrical Equipment Manufacture or Refurbishment	338	338	
UU[c]	(1,831)	(1,831)	(100)
VV[d]	1,833	3,355	200
Total[e]	1,417,591	1,417,446	7,281

[a] Includes estimated increase or decrease in costs following implementation of revisions in RY2023.

[b] Average subsequent year labor costs for Subpart I. Subpart I subsequent year costs include $17,252 in Year 2 and $17,526 in Year 3.

[c] Annual burden includes labor costs and annual O&M savings for two reporters who will begin submitting reports under proposed subpart VV in each year.

[d] Subsequent year labor costs include $2,848 in Year 2 and $3,862 in Year 3. O&M costs are based on $100 in Year 1, $200 in Year 2, and $300 in Year 3.

[e] Subsequent year labor costs include $1,416,802 in Year 2 and $1,418,090 in Year 3.

A full discussion of the cost and emission impacts may be found in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action that was submitted to the OMB for review. This action involves proposed amendments that raise novel legal or policy issues. Any changes made in response to OMB recommendations have been documented in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424.

B. Paperwork Reduction Act

The information collection activities in this proposed rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2300.19. You can find a copy of the ICR in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424, and it is briefly summarized here.

The EPA does not anticipate that the proposed amendments would result in substantial burden, based on the changes to the reporting requirements, in any of the subparts for which amendments are being proposed. In many cases, the proposed amendments to the requirements would reduce the reporting burden by clarifying or improving the estimation methodologies for determining applicability, simplifying calculation methodologies or providing flexibility for monitoring requirements, or simplifying the data that must be reported. The estimated annual average burden is 16,366 hours and $1,424,775 over the 3 years covered by this information collection. The burden costs include $1,424,772 from revisions implemented in the first year, $1,424,082 from revisions implemented in the second year, and $1,425,471 from revisions implemented in the third year. Further information on the EPA's assessment on the impact on burden can be found in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* 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 under the authority provided in CAA section 114.

Estimated number of respondents: 10,041 (affected by proposed amendments).

Frequency of response: Annually.

Total estimated burden: 16,366 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1,424,775, includes $7,281 annualized capital or operation & 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.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *https://www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than August 22, 2022.

C. Regulatory Flexibility Act (RFA)

I certify that this proposed action would 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 businesses 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 an LDC. In the promulgation of the rule, the EPA took several steps to reduce the impact on small entities. For example, the EPA determined appropriate thresholds that reduced the number of small businesses reporting. In addition, the EPA conducted several meetings with industry associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. Except as discussed below, the proposed revisions would not revise these thresholds for existing subparts, therefore, we do not expect any additional small entities will be impacted under the proposed rule revisions. The proposed rule amendments predominantly apply to existing reporters and are amendments that would improve the existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or emissions sources; improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates and improve verification of collected data; and provide additional data to complement or inform other EPA programs under the CAA and to more broadly inform climate programs and policies. We are also proposing revisions that clarify or update provisions that have been unclear, or that streamline or simplify requirements, for example, by increasing flexibility for reporters or removing redundant requirements. In general, these changes are improvements or clarifications of requirements that do not require new data monitoring and would not significantly increase reporter burden, or are changes that require data that is readily available and may be obtained from company records or estimated from existing inputs or data elements already collected under part 98.

In evaluating the impacts of the proposed revisions, we assessed the costs and impacts to small entities in three areas, including revisions to subpart applicability, changes to existing monitoring or calculation methodologies, and revisions to reporting and recordkeeping requirements for data provided to the program. First, we evaluated the costs to entities who may be affected by changes to applicability. In general, this is the area that would be most likely to have greater impacts, as facilities assume substantially higher cost when they become newly applicable to the full set of requirements under part 98 versus the costs associated with an incremental change in an existing requirement. Only the proposed revisions to applicability to subpart I (discussed in section III.E.2 of this preamble) are anticipated to potentially impact new reporters that have not previously reported to the GHGRP. The SBA size standard for facilities falling under the NAICS code 334413 (Semiconductor and Related Device Manufacturing) is 1,250 employees. In the subpart I initial promulgation package, we originally assessed the impact of complying with subpart I requirements on all small entities by calculating a cost-to-sales ratio for six enterprise size ranges using the average total annualized reporting costs to the average annual sales receipts for each establishment (85 FR 74813, December 1, 2010). Based on this analysis, the cost-to-sales ratio for all entity sizes except for the smallest sized enterprises (1 to 20 employee range) was less than one percent. The EPA further concluded that although the cost-to-sales ratio for the 1 to 20 employee range for semiconductor and related device manufacturing was greater than one percent (*i.e.,* 1.16 percent); facilities with emissions greater than 25,000 mtCO_2e per year are unlikely to be included in the 1 to 20 employees size category. Under this proposed action, we estimate there is one (1) affected facility that does not currently report under the GHGRP that may be required to report. The affected facility is included in the 100 to 499 employee range. Although the affected facility meets the SBA size standard for a small business and would potentially incur costs from becoming newly subject the GHGRP ($18,736 in the first year and $17,032 in subsequent years), the costs-to-sales ratio for a facility in this size range would be anticipated to be less than 0.10%. Therefore, we have determined there would not be a significant economic impact on a substantial number of small entities from the proposed revisions to subpart I.

Next, we evaluated the costs and impacts to small entities associated with revisions to monitoring and calculation methodologies to each subpart. For those subparts where the EPA is proposing revisions to update or streamline monitoring and calculation methodologies (*i.e.,* subparts C, G, I, P, and S), we estimate no change or a decrease in burden; therefore, there would be no significant economic impacts on small entities from these proposed revisions. For a subset of subpart W reporters, the proposed monitoring revisions would result in a modest increase in labor costs of $430 per affected reporter, and $12 operation and maintenance costs per reporter. Detailed small business analyses were performed for subpart W in the initial promulgation package from 2011 (75 FR 74458, November 30, 2010) for the eight original industry segments and in the 2015 amendments to subpart W for three additional industry segments (80 FR 64262, October 22, 2015). Both analyses stated that the rule will not have a significant economic impact on a substantial number of small entities, because we concluded that small businesses are unlikely be impacted.[173] Furthermore, because the costs associated with the proposed monitoring revisions are minimal, no significant small entity impacts are anticipated for facilities subject to the proposed subpart W amendments. Because the EPA does not foresee an increase in the number of reporters or any changes in the affected industry

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[173] The original analyses, in section III.D of the 2011 package (75 FR 74458, November 30, 2010), stated, ''smaller enterprises have very small operations (such as a single family owning a few production wells) that are unlikely to cross the 25,000 metric tons CO_2e reporting threshold.'' The second analysis, in section IV.B of the preamble to the 2015 proposed amendments (79 FR 76267; December 9, 2014), stated, ''The petroleum and natural gas industry has a large number of enterprises, the majority of them in the 1–20 employee range. However, a large fraction of production comes from large corporations and not those with less than 20 employee enterprises. The smaller enterprises in most cases deal with very small operations (such as a single family owning a few production wells) that are unlikely to cross the 25,000 metric tons CO_2e threshold.''

segments from the proposed revisions, we have determined that the previous small business analyses still apply and there will not be a significant economic impact on a substantial number of small entities from the proposed revisions to monitoring for subpart W.

Finally, we evaluated the costs associated with revisions to recordkeeping and reporting, specifically revisions to the data elements that are reported in e-GGRT or entered into IVT, for each subpart (C, G, H, I, N, P, Q, S, W, X, Y, BB, DD, GG, HH, OO, PP, and SS). Based on the detailed small business analyses performed for each subpart in the initial promulgation packages (74 FR 56370, October 10, 2009; 75 FR 39738, July 12, 2010; 75 FR 75075, December 1, 2010; and 75 FR 74813, December 1, 2010), the costs associated with the reporting program are estimated to be less than one percent of sales in all firm size categories, with the exception of a small number of entities in the 1 to 20 employee range, which we determined to be unlikely to meet the regulatory thresholds and unlikely to be covered by the rule. With the exception of subpart W, the impacts from the proposed revisions to reporting and recordkeeping in this action for each subpart are less than $100 per entity, with an average annual burden increase of $46 per entity. For subpart C reporters, the highest average burden increase is $44 per facility. Because these costs are minimal, we have determined that the proposed revisions are unlikely to result in costs exceeding more than one percent of sales in any firm size category. For subpart W, the total annual average costs from the proposed revisions to reporting and recordkeeping are $412 per facility. However, as noted above in this section, we do not anticipate any small entities are currently subject to or reporting under subpart W. Further, the proposed revisions to reporting and recordkeeping under subpart W are unlikely to result in costs exceeding more than one percent of sales in any firm size category. Therefore, we have determined there are no significant economic impacts for any potential small entities subject to the revisions to reporting or recordkeeping requirements.

We have therefore concluded that this proposed action will have no significant regulatory burden for any directly regulated small entities and thus that this proposed action would not have a significant economic impact on a substantial number of small entities. Details of this analysis are presented in the memorandum, *Assessment of Burden Impacts for Proposed Revisions for the Greenhouse Gas Reporting Rule* available in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2019–0424. 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. We continue to be interested in the potential impacts of the proposed rule amendments on small entities and welcome comments on issues related to such impacts.

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. The action implements mandate(s) specifically and explicitly set forth in CAA section 114(a)(1) without the exercise of any policy discretion by the EPA.

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.

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 stationary combustion units, cement production facilities, landfills, and petroleum and natural gas facilities 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 8) tribal facilities would be affected. This regulation is not anticipated to impact facilities or suppliers of additional sectors owned by tribal governments. Further, the proposed rule amendments are amendments that would improve the existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or new emission sources for specific sectors; improve the EPA's understanding of the sector-specific processes or other factors that influence GHG emission rates and improve verification of collected data; provide additional data to complement or inform other EPA programs; clarify or update provisions that have been unclear; or that streamline or simplify requirements. In general, these changes are improvements or clarifications of requirements that for the most part would not require new equipment, sampling, or monitoring, and instead, would only require reporters to provide data that is readily available and may be obtained from company records or estimated from existing inputs or data elements already collected under part 98. Therefore, these proposed changes do not significantly change the part 98 requirements that may apply to tribal facilities because they generally do not require new equipment, sampling, or monitoring, and would not substantially increase reporter burden, impose significant direct compliance costs for tribal facilities, or preempt tribal law.

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,[174] 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), 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 proposed rule does not significantly revise the established regulatory requirements and would not

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

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 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 a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The proposed amendments would improve the existing emissions estimation methodologies; implement requirements to collect additional data to understand new source categories or new emission sources for specific sectors; improve the EPA's understanding of factors that influence GHG emission rates; improve verification of collected data; and provide additional data to complement or inform other EPA programs. We are also proposing revisions that clarify or update provisions that have been unclear, or that streamline or simplify requirements, alleviate burden through revision, simplification, or removal of certain calculation, monitoring, recordkeeping, or reporting requirements. In general, these changes would not substantially impact the supply, distribution, or use of energy. In addition, the EPA is proposing confidentiality determinations for new and revised data elements proposed in this rulemaking and for certain existing data elements for which a confidentiality determination has not previously been proposed, or where the EPA has determined that the current determination is no longer appropriate. These proposed amendments and confidentiality determinations do not make any changes to the existing monitoring, calculation, and reporting requirements under part 98 that would affect the supply, distribution, or use of energy.

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

This action involves technical standards. The EPA proposes to allow 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 standard methods based on atomic emission spectrometry 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. Anyone may access the standards on the ASTM website (*https://www.astm.org/*) for additional information. These standards are available to everyone at a cost determined by the ASTM ($50). 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 is also proposing to add new subpart VV for certain EOR operations that choose to use the ISO standard designated as CSA/ANSI ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO2–EOR)* (2019), as a means of quantifying geologic sequestration. The method quantifies CO_2 that is stored in association with EOR operations, focusing on the safe, long-term containment of CO_2 within the EOR complex. CSA/ANSI ISO 27916:2019 identifies and quantifies CO_2 losses (including fugitive emissions) and quantifies the amount of CO_2 stored in association with the CO2–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 ANSI/ISO website (*https://webstore.ansi.org/SDO/ISO/*) for additional information. The standard is available to everyone at a cost determined by ANSI/ISO ($225). ANSI/ISO also offers memberships or subscriptions for reduced costs. Because the proposed standard is optional, the cost of obtaining this standard is not a significant financial burden. 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.

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

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations as it does not affect the level of protection provided to human health or the environment because it is a rule addressing information collection and reporting procedures.

K. Determination Under CAA Section 307(d)

Pursuant to CAA section 307(d)(1)(V), the Administrator determines that this action is subject to the provisions of CAA section 307(d). Section 307(d)(1)(V) of the CAA provides that the provisions of CAA section 307(d) apply to ''such other actions as the Administrator may determine.''

List of Subjects

40 CFR Part 9

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

40 CFR Part 98

Environmental protection, Administrative practice and procedure, 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 proposes to amend 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 ''98.1–98.489'' 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	
98.1–98.489	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 § 98.1 by revising paragraph (c) to read as follows:

§ 98.1 Purpose and scope.

* * * * *

(c) For facilities required to report under onshore petroleum and natural gas production under subpart W of this part, the terms *Owner* and *Operator* used in this subpart have the same definition as *Onshore petroleum and natural gas production owner or operator,* as defined in § 98.238. For facilities required to report under onshore petroleum and natural gas gathering and boosting under subpart W of this part, the terms *Owner* and *Operator* used in this subpart have the same definition as *Gathering and boosting system owner or operator*, as defined in § 98.238. For facilities required to report under onshore natural gas transmission pipeline under subpart W of this part, the terms *Owner* and *Operator* used in this subpart have the same definition as *Onshore natural gas transmission pipeline owner or* operator, as defined in § 98.238.

■ 5. Amend § 98.2 by revising paragraphs (f)(1) and (i)(1) and (2) and adding paragraph (k) to 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 CO_2e 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 (k)(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 of 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.

■ 6. Amend § 98.3 by revising paragraphs (b)(2) and (h)(4) to 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). 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) 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) 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.

* * * * *

■ 7. Amend § 98.4 by revising paragraph (h) and adding paragraph (n) to read as follows:

§ 98.4 Authorization and responsibilities of the designated representative.

* * * * *

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

* * * * *

(n) *Alternative provisions for changes in owners and operators for industry segments with a unique definition of facility as defined in § 98.238.* When there is a change to the owner or operator of a facility required to report under the onshore petroleum and natural gas production, natural gas distribution, onshore petroleum and natural gas gathering and boosting, or onshore natural gas transmission pipeline industry segments of subpart W of this part, or a change to the owner or operator for some emission sources from the facility in one of these industry segments, the provisions specified in paragraphs (n)(1) through (4) of this section apply for the respective type of change in owner or operator and the provisions specified in paragraph (n)(5) of this section apply to all types of change in owner or operator for such facilities.

(1) If the entire facility is acquired by an owner or operator that does not already have a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), a certificate of representation that is complete under this section shall be submitted to reflect the new owner or operator within 90 days after the change in the owner or operator and according to the procedure specified in paragraph (b) of this section. If the new owner or operator already had emission sources listed in the applicable paragraph of § 98.232 prior to the acquisition in the same basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution) as the acquired facility but had not previously met the applicability requirements in § 98.2(a) and § 98.231, then per the applicable definition of facility in § 98.238, the previously owned applicable emission sources must be included in the acquired facility. The new owner or operator and the new designated representative shall be responsible for submitting the annual report for the facility for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(2) If the entire facility is acquired by an owner or operator that already has a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), the new owner or operator shall merge the acquired facility with their existing facility for purposes of the annual GHG report. Within 90 days after the change in the owner or operator, a certificate of representation that is complete under this section shall be submitted for the acquired facility to reflect the new owner or operator. The owner or operator shall also follow the provisions of § 98.2(i)(6) to notify EPA that the acquired facility will discontinue reporting and shall provide the e-GGRT identification number of the merged, or reconstituted, facility. The owner or operator of the merged facility shall be responsible for submitting the annual report for the merged facility for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(3) If only some emission sources from the facility are acquired by one or more new owners or operators, the existing owner or operator (*i.e.,* the owner or operator of the portion of the facility that is not sold) shall continue to report under subpart W of this part for the retained emission sources unless and until that facility meets one of the criteria in § 98.2(i). Each owner or operator that acquires emission sources from the facility must account for those acquired emission sources according to paragraph (n)(3)(i) or (ii) of this section, as applicable.

(i) If the purchasing owner or operator that acquires only some of the emission sources from the existing facility does not already have a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), the purchasing owner or operator shall begin reporting as a new facility. The new facility must include the acquired emission sources listed in the applicable paragraph of § 98.232 and any emission sources the purchasing owner or operator already owned in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution). The designated representative for the new facility must be selected by the purchasing owner or operator according to the schedule and procedure specified in paragraphs (b) through (d) of this section. The purchasing owner or operator shall be responsible for submitting the annual report for the new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(ii) If the purchasing owner or operator that acquires only some of the emission sources from the existing facility already has a reporting facility in the same industry segment and basin (for onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting) or state (for natural gas distribution), then per the applicable definition of facility in § 98.238, the purchasing owner or operator must add the acquired emission sources listed in the applicable paragraph of § 98.232 to their existing facility for purposes of reporting under subpart W. The purchasing owner or operator shall be responsible for submitting the annual report for the entire facility, including the acquired emission sources, for the entire reporting year beginning with the reporting year in which the acquisition occurred.

(4) If all the emission sources from a facility are sold to multiple owners or operators, such that the current owner or operator of the existing facility does not retain any of the emission sources, then the current owner or operator of the existing facility shall notify EPA within 90 days of the transaction that all of the facility's emission sources were acquired by multiple purchasers. Each owner or operator that acquires emission sources from a facility shall account for those sources according to paragraph (n)(3)(i) or (ii) of this section, as applicable.

(5) Each owner or operator involved in a transaction that results in a change to the owner or operator of a facility shall, as part of the acquisition agreement or ownership transfer contract, agree upon the entity who will be responsible for revisions to annual GHG reports under § 98.3(h) for reporting years prior to the reporting year in which the transaction occurred. That responsible entity will select a representative who will submit revisions to annual GHG reports under § 98.3(h) for that facility. If the selected individual is not the designated representative for the facility, the individual must be designated as the alternate designated representative or an agent for the facility.

■ 8. Amend § 98.6 by:

■ a. Revising the definitions for ''Carbon dioxide stream'', ''Dehydrator'', and ''Dehydrator vent emissions;''

■ b. Removing the definition for ''Desiccant'';

■ c. Adding a definition for ''Direct air capture (DAC)'' in alphabetical order; and

■ d. Revising the definition for ''Vapor recovery system''.

The revisions and addition read follows:

§ 98.6 Definitions.

* * * * *

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.

* * * * *

Dehydrator means a device in which a liquid absorbent (*e.g.,* ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) regenerator and, if present, a flash tank separator, to the atmosphere, flare, regenerator fire-box/fire tubes, or vapor recovery system. Emissions include stripping natural gas and motive natural gas used in absorbent circulation pumps.

* * * * *

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.

* * * * *

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel. For purposes of § 98.233, routing emissions from a dehydrator regenerator still vent or flash tank separator vent to a regenerator fire-box/fire tubes does not meet the definition of vapor recovery system.

* * * * *

■ 9. Amend § 98.7 as follows:

■ a. Revise the introductory text;

■ b. In paragraph (c)(1), remove the text '', incorporation by reference (IBR)'' and add, in its place, the text ''; IBR'';

■ c. Redesignate paragraph (e)(38) as paragraph (e)(39);

■ d. Add new paragraph (e)(38) and paragraph (g)(6); and

■ e. In addition to the previous amendments to this section, remove the text '', IBR'' and add, in its place, the text ''; IBR'' wherever it appears throughout this section.

The revision and additions 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. For information on the availability of this material at NARA, email *fr.inspection@nara.gov,* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.* The material may be obtained from the following source(s):

* * * * *

(e) * * *

(38) ASTM E415–17, Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry; IBR approved for § 98.174(b).

* * * * *

(g) * * *

(6) CSA/ANSI ISO 27916:19, Carbon dioxide capture, transportation and geological storage—Carbon dioxide storage using enhanced oil recovery (CO_2-EOR). Edition 1. January 2019; IBR approved for §§ 98.480(a), 98.481(a) and (b), 98.482, 98.483, 98.484, 98.485, 98.486(g), 98.487, 98.488(a)(5), and 98.489.

* * * * *

■ 10. Amend table A–1 to subpart A of part 98 by:

■ a. Adding under the heading ''Other Fluorinated Compounds'' the entry ''Carbonyl fluoride'' after the entry ''2-Bromo-2-chloro-1,1,1-trifluoroethane (Halon-2311/Halothane);''

■ b. Removing the heading ''Fluorinated GHG Group [d]'' and adding in its place the heading ''Fluorinated GHG Group [e]''

■ c. Revising the entry ''Unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, fluorinated aldehydes, and fluorinated ketones'' under the revised heading ''Fluorinated GHG Group; [e]''

■ d. Redesignating footnote ''d'' as footnote ''e;'' and

■ e. Adding new footnote "d" and footnote "f."

The additions and revisions read as follows:

* * * * *

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
* * * * * * *			
Other Fluorinated Compounds			
* * * * * * *			
Carbonyl fluoride	353–50–4	COF_2	[d] 0.14
Fluorinated GHG Group [e]			
* * * * * * *			
Unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, unsaturated bromofluorocarbons, unsaturated chlorofluorocarbons, unsaturated bromochlorofluorocarbons, unsaturated hydrobromofluorocarbons, unsaturated hydrobromochlorofluorocarbons, fluorinated aldehydes, and fluorinated ketones [f]			1
* * * * * * *			

* * * * *

[d] This compound was added to Table A–1 in the final rule published on [Date of publication of the final rule in the FEDERAL REGISTER] and effective on January 1, 2023.

[e] 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 § 98.98), whether or not they are also fluorinated GHGs.

[f] This fluorinated GHG group was updated in the final rule published on [Date of publication of the final rule in the **Federal Register**] and effective on January 1, 2023.

■ 11. Amend table A–3 to subpart A of part 98 by:

■ a. Revising the entry "Electrical transmission and distribution equipment use at facilities where the total nameplate capacity of SF6 and PFC containing equipment exceeds 17,820 pounds, as determined under § 98.301 (subpart DD).";

■ b. Removing the entry for "Electrical transmission and distribution equipment manufacture or refurbishment (subpart SS)."; and

■ c. Adding the entry "Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916 (subpart VV)." at the end of the table.

The revision and addition read as follows:

* * * * *

TABLE A–3 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(1)

* * * * * * *
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), are equivalent to 25,000 metric tons CO_2e or more per year.
* * * * * * *
Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916 (subpart VV).

[a] Source categories are defined in each applicable subpart.

* * * * *

■ 12. Amend table A–4 to subpart A of part 98 by adding the entry "Electrical transmission and distribution equipment manufacture or refurbishment, as determined under § 98.451 (subpart SS)." after the entry "Industrial wastewater treatment (subpart II)." to read as follows:

TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)

* * * * * * *
Additional Source Categories [a] Applicable in Reporting Year 2011 and Future Years
* * * * * * *
Electrical transmission and distribution equipment manufacture or refurbishment, as determined under § 98.451 (subpart SS).

TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)—Continued

* * * * * * *

[a] Source categories are defined in each applicable subpart.

* * * * *

Subpart C—General Stationary Fuel Combustion Sources

■ 13. Amend § 98.33 by:

■ a. Revising parameters ‘‘CC’’ and ‘‘MW’’ of Equation C–5 in paragraph (a)(3)(iii) introductory text;

■ b. Adding paragraphs (a)(3)(iii)(A) and (B);

■ c. Revising paragraph (b)(1)(vii);

■ d. Revising parameter ‘‘EF’’ of Equations C–8 in paragraph (c)(1) introductory text, C–8a in paragraph (c)(1)(i), C–8b in paragraph (c)(1)(ii), C–9a in paragraph (c)(2), C–9b in paragraph (c)(3), and C–10 in paragraph (c)(4) introductory text;

■ e. Revising paragraphs (c)(6)(i), (c)(6)(ii) introductory text, and (c)(6)(ii)(A) and (C);

■ f. Removing and reserving paragraph (c)(6)(ii)(B);

■ g. Revising parameter ‘‘R’’ of Equation C–11 in paragraph (d)(1); and

■ h. Revising the introductory text of paragraphs (e), (e)(1), (e)(2)(v), and (e)(3) and paragraph (e)(3)(iv).

The additions and revisions read as follows:

§ 98.33 Calculating GHG emissions.

* * * * *

(a) * * *

(3) * * *

(iii) * * *

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 (a)(3)(iii)(A)(*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)(A)(*3*) and (a)(3)(iii)(A)(*4*) of this section.

* * * * *

(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 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 of this section. If multiple carbon content determinations are made in any month, average the values for the month arithmetically.

$$(CC)_{annual} = \frac{\sum_{i=1}^{n}(CC)_i*(Fuel)_i*(MW)_i\ /\ MVC}{\sum_{i=1}^{n}(Fuel)_i*(MW)_i\ /\ MVC} \qquad \text{(Eq. C-5a)}$$

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 (a)(3)(iii)(B)(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 of this section. If multiple molecular weight determinations are made in any month, average the values for the month arithmetically.

$$(MW)_{annual} = \frac{\sum_{i=1}^{n}(MW)_i*(Fuel)_i\ /\ MVC}{\sum_{i=1}^{n}(Fuel)_i\ /\ MVC} \quad (Eq. C\text{-}5b)$$

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)(A)(*3*) 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) * * *

(1) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(i) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(ii) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(2) * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(3) * * *

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(4) * * *

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

* * * * *

(6) * * *

(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:

(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'';

* * * * *

(C) Calculate the annual CH_4 and N_2O emissions from component ''i'', using Equation C–8 (fuel mass or volume), C–8a (fuel heat input), C–8b (fuel heat input), C–9a (fuel mass or volume), or C–10 (fuel heat input) of this section, as applicable;

* * * * *

(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 of this section, MSW, and tires. In addition, when a biomass fuel that is not listed in Table C–1 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 § 98.33(b)(3)(iii), 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 of this subpart to calculate the annual CO_2 mass emissions from the combustion of the biomass fuels listed in Table C–1 of 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):

* * * * *

(2) * * *

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

* * * * *

(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 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 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.

* * * * *

■ 14. Amend § 98.34 by revising paragraphs (c)(6) and (d) 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 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis) and ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (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.

* * * * *

■ 15. Amend § 98.36 by:

■ a. Revising paragraphs (c)(1) introductory text, (c)(1)(ii) and (vi), (c)(3) introductory text, and (c)(3)(vi);

■ b. Adding paragraph (c)(3)(xi); and

■ c. Revising paragraphs (e)(2)(ii)(C) and (e)(2)(xi).

The revisions and addition read as follows:

§ 98.36 Data reporting requirements.

* * * * *

(c) * * *

(1) *Aggregation of units.* If a facility contains two or more units (*e.g.,* boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. Compressor drivers that calculate emissions using an applicable CH_4 emission factor from Table W–9 to subpart W of this part, must be reported as their own aggregation of units configuration, according to design class (*i.e.,* two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn). You may not have a combination of one design class of compressor driver (using one Table W–9 CH_4 emission factor) and other combustion units (*e.g.,* using a Table C–2 CH_4 emission factor or another Table W–9 CH_4 emission factor) in the same aggregation of units configuration. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

* * * * *

(ii) For each unit in the group greater than or equal to 10 mmBtu/hr, the unit type, maximum rated heat input capacity, and an estimate of the total annual heat input (expressed as a decimal fraction). To determine the total annual heat input decimal fraction for a unit, divide the actual heat input for that unit (all fuels) by the sum of the actual heat input for all units (all fuels), including units less than 10 mmBtu/hr. Estimates of the actual heat inputs may be based on company records. If all units in this configuration are less than 10 (mmBtu/hr), this requirement does not apply.

* * * * *

(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) *Common pipe configurations.* When two or more stationary combustion units at a facility combust the same type of liquid or gaseous fuel and the fuel is fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter, or, for natural gas, the amount of fuel combusted may be obtained from gas billing records. For Tier 3 applications, the flow meter shall be calibrated in accordance with § 98.34(b). If a portion of the fuel measured (or obtained from gas billing records) at the main supply line is diverted to either: A flare; or another stationary fuel combustion unit (or units), including units that use a CO_2 mass emissions calculation method in part 75 of this chapter; or a chemical or industrial process (where it is used as a raw material but not combusted), and the remainder of the fuel is distributed to a group of combustion units for which you elect to use the common pipe reporting option, you may use company records to subtract out the diverted portion of the fuel from the fuel measured (or obtained from gas billing records) at the main supply line prior to performing the GHG emissions calculations for the group of units using the common pipe option. If the diverted portion of the fuel is combusted, the GHG emissions from the diverted portion shall be accounted for in accordance with the applicable provisions of this part. When the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration, except where the applicable tier is based on criteria other than unit size. For example, if the maximum rated heat input capacity of the largest unit is greater than 250 mmBtu/hr, Tier 3 will apply, unless the fuel transported through the common pipe is natural gas or distillate oil, in which case Tier 2 may be used, in accordance with § 98.33(b)(2)(ii). As a second example, in accordance with § 98.33(b)(1)(v), Tier 1 may be used regardless of unit size when natural gas is transported through the common pipe, if the annual fuel consumption is obtained from gas billing records in units of therms or mmBtu. Compressor drivers that calculate emissions using an applicable CH_4 emission factor from Table W–9 to subpart W of this part, must be reported as their own common pipe configuration, according to design class (*i.e.,* two-stroke lean-burn, four-stroke lean-burn, and four-stroke rich-burn). You may not have a combination of one design class of compressor driver (using one Table W–9 CH_4 emission factor) and other combustion units (*e.g.,* using a Table C–2 CH_4 emission factor or another Table W–9 CH_4 emission factor) in the same common pipe configuration. When the common pipe reporting option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

* * * * *

(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.

* * * * *

(xi) For each unit in the group greater than or equal to 10 mmBtu/hr, the unit type, maximum rated heat input capacity, and an estimate of the total annual heat input (expressed as a decimal fraction). To determine the total annual heat input decimal fraction for a unit, divide the actual heat input for that unit (all fuels) by the sum of the actual heat input for all units (all fuels), including units less than 10 mmBtu/hr. Estimated heat input values may be based on company records. If all units in this configuration are less than 10 (mmBtu/hr), this requirement does not apply.

* * * * *

(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).

* * * * *

■ 16. Amend § 98.37 by revising paragraphs (b) introductory text, (b)(9) through (11), (14), (18), (20), (22), and (23) to read as follows:

§ 98.37 Records that must be retained.

* * * * *

(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), (e)(2)(ii)(C), (e)(2)(ii)(D), (e)(2)(iv)(A), (e)(2)(iv)(C), (e)(2)(iv)(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.

* * * * *

(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 of § 98.33). Annual average HHV of each solid fuel (mmBtu per ton) (Equation C–2a of § 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). Annual average HHV of each liquid fuel (mmBtu per gallons) (Equation C–2a of § 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). Annual average HHV of each gaseous fuel (mmBtu per scf) (Equation C–2a of § 98.33).

* * * * *

(14) Volume of each gaseous fuel combusted during month (scf) (Equation C–2b, Equation C–5a, Equation C–5b).

* * * * *

(18) Annual average carbon content of each solid fuel (percent by weight, expressed as a decimal fraction) (Equation C–3). 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—see the definition of ''CC'' in Equation C–3).

* * * * *

(20) Annual average carbon content of each liquid fuel (kg C per gallon of fuel) (Equation C–4). 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—see the definition of ''CC'' in Equation C–3).

* * * * *

(22) Annual average carbon content of each gaseous fuel (kg C per kg of fuel) (Equation C–5). 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).

(23) Annual average molecular weight of each gaseous fuel (kg/kg-mole) (Equation C–5). 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).

* * * * *

■ 17. Amend table C–2 to subpart C of part 98 by revising the entry ''Natural Gas'' to read as follows:

TABLE C–2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
* * * * * * *		
Natural Gas[1]	1.0×10^{-03}	1.0×10^{-04}
* * * * * * *		

* * * * *

Subpart G—Ammonia Manufacturing

■ 18. 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.

* * * * *

■ 19. 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 net 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 of this section:

$$\mathrm{CO}_{2,G} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}\right) * 0.001 \qquad \text{(Eq.G-1)}$$

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 of this section:

$$\mathrm{CO}_{2,L} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_n * CC_n\right) * 0.001 \qquad \text{(Eq.G-2)}$$

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).

---

[1] Reporters subject to subpart W of this part may only use the default CH_4 emission factor for natural gas-fired combustion units that are not compressor drivers. For natural gas-fired compressor drivers at facilities subject to subpart W of this part, reporters must use the applicable CH_4 emission factor from Table W–9 to subpart W of this part.

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 of 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) *Net CO_2 process emissions.* You must calculate the annual net CO_2 process emissions at each ammonia manufacturing unit according to Equation G–4 of this section:

$$CO_{2,net} = \sum_{p=1}^{3} CO_{2,p} - \sum_{n=1}^{12} CO_{2,urea,n} - \frac{44}{32} \sum_{n=1}^{12} MeOH_n \qquad \text{(Eq.G-4)}$$

Where:

$CO_{2,net}$ = Annual net 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.
$CO_{2,urea,n}$ = Amount of carbon dioxide collected from ammonia production and consumed on site for urea production, in month n (metric tons).
$MeOH_n$ = Mass of methanol intentionally produced as a desired product for month n (metric tons).
44/32 = Ratio of molecular weights, CO_2 to methanol.

* * * * *

■ 20. Amend § 98.76 by revising the introductory text and paragraphs (b)(1) and (13) 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 net CO_2 process emissions (metric tons) for each ammonia manufacturing unit.

* * * * *

(13) Annual amount of CO_2 collected from ammonia production (metric tons) and consumed on site for urea production and the method used to determine the CO_2 consumed in urea production.

* * * * *

■ 21. Amend § 98.77 by revising paragraph (c) introductory text and adding paragraphs (c)(8) and (9) to read as follows:

§ 98.77 Records that must be retained.

* * * * *

(c) 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 (c)(1) through (9) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (c)(1) through (9) of this section.

* * * * *

(8) Quantity of CO_2 collected from ammonia production and consumed on site for urea production in month (Equation G–4 of § 98.73).

(9) Quantity of methanol intentionally produced as a desired product in month (metric tons) (Equation G–4).

Subpart H—Cement Production

■ 22. Amend § 98.83 by:
■ a. Revising paragraph (d)(1);
■ b. Revising parameters ''CKD_{CaO},'' ''CKD_{CaO},'' ''CKD_{MgO},'' 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 of 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_{CaO} = Quarterly total CaO content of CKD not recycled to the kiln, wt-fraction.
CKD_{ncCaO} = Quarterly non-calcined CaO content of CKD not recycled to the kiln, wt-fraction.

* * * * *

CKD_{MgO} = Quarterly total MgO 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 of 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 CO2 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, CO2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

* * * * *

■ 23. Amend § 98.86 by adding paragraphs (a)(4) through (13) 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 arithmetic average of total CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(9) Annual arithmetic average of non-calcined CaO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(10) Annual arithmetic average of total MgO content of CKD not recycled to the kiln(s) at the facility, wt-fraction.

(11) Annual arithmetic average of non-calcined MgO content not recycled to the kiln(s) at the facility, wt-fraction.

(12) Annual facility CKD not recycled to the kiln(s), tons.

(13) The amount of raw kiln feed consumed annually at the facility, tons (dry basis).

(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

■ 24. Amend § 98.91 by revising paragraphs (a) introductory text and (a)(1) through (3), and parameters ‘‘E_i’’ and ‘‘i’’ of Equation I–4 in paragraph (a)(4) 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 (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. 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 of this subpart, or the consumption of each input gas, the default emission factors shown in Table I–2 to this subpart, and Equation I–1B of this subpart.

$$E_i = S * EF_i * GWP_i * 0.001 \qquad \text{(Eq. I-1A)}$$

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 of this subpart (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.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \qquad \text{(Eq. I-1B)}$$

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 (a)(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–2 of this subpart or the consumption of each input gas, the default emission factors shown in Table I–2 to this subpart, and Equation I–1B of this subpart.

$$E_i = S * EF_i * GWP_i * 0.000001 \qquad \text{(Eq. I-2A)}$$

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 of this subpart (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 (a)(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 of this subpart.

$$E_i = C_i * (GWP_i * (1 - U_i) + GWP_{CF4} * BCF_4 + GWP_{C2F6} * BC_2F_6) * 0.001 \qquad \text{(Eq. I-3)}$$

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 (a)(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) * * *

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 of this subpart.

i = Emitted gas.

* * * * *

■ 25. Amend § 98.92 by revising paragraph (a) 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 § 98.98). 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:

* * * * *

■ 26. Amend § 98.93 by:

■ a. Revising paragraph (a)(1) introductory text;

■ b. Revising parameters "E_{ij}" and "N" of Equation I–6 in paragraph (a)(1) introductory text;

■ c. Revising Equation I–7 in paragraph (a)(1) introductory text;

■ d. Revising parameters "BE_{ijk}" and "N" of Equation I–7 in paragraph (a)(1) introductory text;

■ e. Revising paragraphs (a)(1)(i) and (ii) and (a)(2) and (6);

■ f. Adding paragraph (a)(7);

■ g. Revising the introductory text of paragraphs (e) and (i);

■ h. Removing and reserving paragraphs (i)(1) and (2);

■ i. Revising paragraph (i)(3) introductory text and (i)(3)(i), (iii) through (vi), and (viii));

■ j. Adding paragraph (i)(3)(ix);

■ k. Revising paragraph (i)(4); and

■ l. Removing paragraph (i)(5).

The revisions and additions read as follows:

§ 98.93 Calculating GHG emissions.

(a) * * *

(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 of this subpart. 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 of this subpart, plus any by-product emissions of that gas calculated under paragraph (a) of this section.

* * * * *

E_{ij} = Annual emissions of input gas i from process sub-type or process type j as calculated in Equation I–8A of this subpart (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 of this subpart, N = 1.

* * * * *

$$ProcesstypeBE_k = \sum_{j=1}^{N} \sum_i BE_{kij} \qquad \text{(Eq. I-7)}$$

* * * * *

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 of this subpart (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 of this subpart, N = 1.

* * * * *

(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 of this subpart, and by using Equations I–8A and I–8B of this subpart.

$$E_{ij} = C_{ij}\left(1 - U_{ij}\right) * \left(1 - \left(a_{ij} * d_{ij} * UT_{ij}\right)\right) * 0.001 \qquad \text{(Eq. I-8A)}$$

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 of this subpart, 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 on 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 of this subpart, 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.

$$BE_{kij} = B_{ijk} * C_{ij} * \left(1 - \left(a_{kij} * d_{kij} * UT_{kij}\right)\right) * 0.001 \qquad \text{(Eq. I-8B)}$$

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_{ijk} = 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). For non-carbon containing input gases used in chamber cleaning process sub-types, this is zero when the combination of 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).

C_{ij} = Amount of input gas i consumed for process sub-type, or process type j, as calculated in Equation I–13 of this subpart, 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 of this subpart.

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 of this subpart, and by using Equations I–8A and I–8B of this subpart.

* * * * *

(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 of this subpart, as appropriate, and by using Equations I–8A and I–8B of this subpart. 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, 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 of this subpart, plus any by-product emissions of that gas calculated under this paragraph (a).

* * * * *

(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 (a)(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, 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 of this subpart.

(7) If your fab employs hydrocarbon-fuel-based emissions control systems (including, but not limited to, abatement systems as defined at § 98.98) 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 using default utilization and by-product formation rates as shown in Table I–3 or I–4 of this subpart. A hydrocarbon-fuel-based emissions control system 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 hydrocarbon-fuel-based emissions control system.

$$EAB_{CF_4} = \sum_j C_{F_2,j} \bullet \left(1 - U_{F_2,j}\right) \bullet a_{F_2,j} \bullet UT_{F_2,j} \bullet AB_{CF_4,F_2} + C_{NF_3,RPC} \cdot B_{F_2,NF_3} \cdot a_{NF_3,RPC} \cdot UT_{NF_3,RPC,F2} \cdot AB_{CF_4,F_2} \qquad \text{(Eq. I-9)}$$

Where:

EAB_{CF4} = Emissions of CF_4 from hydrocarbon-fuel-based emissions control systems 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 of this subpart, 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 hydrocarbon-fuel-based abatement systems 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 hydrocarbon-fuel-based emissions control systems 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 abatement systems connected to process tools in the fab using F2 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 combustion abatement system. 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 of this subpart, 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 hydrocarbon-fuel-based abatement systems 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 hydrocarbon-fuel-based emissions control systems 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 abatement systems 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 of this subpart.

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 of this subpart. Where a gas supply system serves more than one fab, Equation I–13 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 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 of this subpart.

* * * * *

(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 paragraph (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.

* * * * *

(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 or I–19A and I–19c of this subpart. Use Equation I–19A to calculate the controlled emissions for each 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 $\boldsymbol{\Sigma}_s E_{i,s}$ (the total measured emissions of the fluorinated GHG across all stack systems, calculated based on the results of Equation I–17) is less than or equal to $E_{imax,f}$ calculated in I–19A, use Equation I–19B to calculate the emission factor for that fluorinated GHG. If $\boldsymbol{\Sigma}_s E_{i,s}$ is larger than the $E_{imax,f}$ calculated in I–19A, use Equation I–19C to calculate the emission factor and treat the difference between the total measured emissions $\boldsymbol{\Sigma}_s E_{i,s}$ and the maximum expected controlled emissions $E_{imax,f}$ as a by-product of the other input gases, using Equation I–20 of this subpart.

$$E_{imax,f} = 0.8 \bullet Activity_{if} \bullet \left(1 - UT_f \bullet a_{if} \bullet d_{if}\right) \qquad \text{(Eq. I-19A)}$$

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 of this subpart (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.

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 of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

$$EF_{if} = \frac{\sum_s (E_{is})}{Activity_{if} * \left(UT_f + \left(\frac{1 - UT_f}{1 - \left(a_{if} \bullet d_{if}\right)} \right) \right)} \qquad \text{(Eq. I-19B)}$$

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 of this subpart (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.

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 of this subpart (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.

$$EF_{if} = 0.8 \bullet \left(1 - a_{if} \bullet d_{if}\right) \qquad \text{(Eq. I-19C)}$$

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.

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 of this subpart (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 of this subpart. When calculating the by-product emission factor for an input gas for which $\boldsymbol{\Sigma}_s E_{i,s}$ equals or exceeds $E_{imax,f}$, exclude the consumption of that input gas from the term "$\boldsymbol{\Sigma}(Activity_{if})$."

$$EF_{kf} = \frac{\sum_s (E_{ks})}{\sum_i Activity_{if} * \left(UT_f + \left(\frac{1 - UT_f}{1 - \left(a_{kif} * d_{kif}\right)} \right) \right)} \qquad \text{(Eq. I-20)}$$

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 of this subpart (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.

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 of this subpart (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 of this section.

$$E_{if} = EF_{if} \bullet C_{if} \bullet UT_f + \frac{EF_{if}}{\left(1-(a_{if} \bullet d_{if})\right)} \bullet C_{if} \bullet \left(1 - UT_f\right) \qquad \text{(Eq. I-21)}$$

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 of this subpart (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 of this subpart (kg/year).

UT_f = The total uptime of all abatement systems for fab f, during the reporting year, as calculated using Equation I–23 of this subpart (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.

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 of this subpart (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 of this section.

$$E_{kf} = EF_{kf} \bullet \sum\nolimits_i C_{if} \bullet UT_f + EF_{kf} \bullet \sum\nolimits_i \frac{C_{if} \bullet (1-UT_f)}{1-a_{kif} \bullet d_{kif}} \qquad \text{(Eq. I-22)}$$

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 of this subpart (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 of this subpart.

UT_f = The total uptime of all abatement systems for fab f, during the reporting year as calculated using Equation I–23 of this subpart (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.

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 of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

k = Fluorinated GHG by-product

* * * * *

(viii) When using the stack testing option described in paragraph (i) of this section 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 (for input gases) and Equation I–24B (for by-product gases) of this subpart and Table I–18 of 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 (for input gases) and Equation I–24D (for by-product gases) and Table I–18 of 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 of this subpart, as applicable, and by using Equations I–8A, I–8B, I–9, and I–13 of this subpart. 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.

■ 27. Amend § 98.94 by revising paragraphs (c) introductory text, (e), (f)(3), (f)(4) introductory text, (f)(4)(iii), (j)(1) introductory text, (j)(1)(i), (j)(3) introductory text, (j)(5)(i), and (j)(5)(ii) introductory text and by removing and reserving paragraphs (j)(6) and (j)(8)(v).

The revisions 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 of this subpart), 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 hydrocarbon-fuel-based emissions control systems 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, 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 emissions control system manufacturer. Hydrocarbon-fuel-based 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, adjusted to calculate the rate of conversion from F_2 to CF_4 rather than the DRE. Either the hydrocarbon-fuel-based emissions control system manufacturer or the electronics manufacturer may perform the measurement. The flow rate of F_2 into the tested emissions control system(s) 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 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 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 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 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 operational.

(4) If you calculate and report controlled emissions using neither the default destruction or removal efficiency values in Table I–16 of this subpart nor a manufacturer verified lower destruction or removal efficiency values 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 and you elect to reflect emission reductions due to these systems. You must not use a default value from Table I–16 of 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 of 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 emissions control systems 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) * * *

(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.

* * * * *

■ 28. Amend § 98.96 by:

■ a. Revising paragraphs (c)(1) and (2), (o), (p)(2), and (q)(2) and (3);

■ b. Revising Equation I–28 in paragraph (r)(2);

■ c. Revising parameters ''C_{if},'' ''EF_{kf},'' ''a_f,'' and ''d_{kf}'' of Equation I–28 in paragraph (r)(2); and

■ d. Revising paragraphs (w)(2), (y) introductory text, (y)(1), (y)(2)(i) and (iv), and (y)(4).

The revisions read as follows:

§ 98.96 Data reporting requirements.

* * * * *

(c) * * *

(1) When you use the procedures specified in § 98.93(a) of this subpart, 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 of this subpart.

(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 of this subpart, as applicable.

* * * * *

(o) For all hydrocarbon-fuel-based emissions control systems 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, 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 emissions control system manufacturer, unless the emissions control system is included in the count of systems not certified to not form CF_4 in Equation I–9. Hydrocarbon-fuel-based 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 emissions control system manufacturer, you must provide documentation from the emissions control system 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 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, including but not limited to 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. 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) * * *

$$SFGHG = \sum_i \left[\frac{EF_{if}}{\left(1-(a_{if} * d_{if})\right)} * C_{if} * GWP_i \right] + \sum_k \left[EF_{kf} * \sum_i \frac{C_{if}}{1-(a_{kif} \bullet d_{ik})} * GWP_k \right] \qquad \text{Eq. I-28)}$$

* * * * *

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 of this subpart (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.

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 of this subpart, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

* * * * *

(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, 2023 is due on March 31, 2025, 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 all of the methods specified in paragraphs (y)(2)(iv)(A) through (C) of this section if multiple fluorinated input gases are used. If only one fluorinated input gas is fed into the process, you must use Equations I–29a and I–29b. 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 condition used for the measurement.

(A) *Dominant gas method.* Use Equation I–29a 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, you must instead use Equation I–29c to calculate the input gas emission factor for that F–GHG and Equation I–29d to calculate the by-product formation rate for that F–GHG from the other input F–GHGs. To calculate by-product emission factors for all other measured F–GHGs, use Equation I–29b and assign all measured by-products to the dominant gas. The dominant gas is the carbon-containing input F–GHG fed into the process in the largest quantity (mass). If there are no carbon containing input F–GHGs, the dominant gas is the input F–GHG with the largest input mass.

$$\left(1 - U_{ij}\right) = \frac{(E_i)}{(Mass_i)} \qquad \text{(Eq. I-29a)}$$

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 input gas i.

$$BEF_{ki} = \frac{(E_k)}{Mass_i} \qquad \text{(Eq. I -29b)}$$

Where:

BEF_{ki} = By-product formation rate for gas k from input gas i, 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 where i is the dominant gas, as defined in (A).

i = Fluorinated GHG input gas i.

k = By-product gas k.

$$\left(1 - U_{ij}\right) = 0.8 \qquad \text{(Eq. I-29c)}$$

Where:

Uij = 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 where i is the dominant gas, as defined in (A).

$Mass_g$ = 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) *All-input gas method.* Use Equation I–30a to calculate the input gas emission factor ($1–U_{ij}$) for each input gas in a single test. If the result of Equation I–30a exceeds 0.8 for an F–GHG, you must use Equation I–30c to calculate the input gas emission factor for that F–GHG and Equation I–30d to calculate the by-product formation rate for that F–GHG from the other input gases. Use Equation I–30b 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–30b and I–30d, respectively.

$$\left(1 - U_{ij}\right) = \frac{(E_i)}{(Mass_i)} \qquad \text{(Eq. I-30a)}$$

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.

$$\mathrm{BEF}_{kji} = \frac{(\mathrm{E}_k)}{\sum_i \mathrm{Mass}_i} \qquad \text{(Eq. I -30b)}$$

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.

$$\left(1 - U_{ij}\right) = 0.8 \qquad \text{(Eq. I-30c)}$$

Where:

Uij = Process utilization rate for fluorinated GHG i, process type j.

$$BEF_{ijg} = \frac{(E_i - 0.8 * Mass_i)}{\sum_g Mass_g} \qquad \text{(Eq. I -30d)}$$

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.

(C) *Reference emission factor method.* Calculate the input gas emission factors and by-product formation rates from a test using Equations I–31a and I–31b, and Table I–19 or I–20 of this subpart. In this case, use Equation I–31a to calculate the input gas emission factors and use Equation I–31b and I–30b to calculate the by-product formation rates.

$$(1-U_{ij})=(1-U_{ijr})*\left[\frac{E_i}{(Mass_i*(1-U_{ijr})+\sum_g Mass_g BEF_{ijgr})}\right] \qquad \text{(Eq. I-31a)}$$

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 of 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.

i = Fluorinated GHG.

g = Fluorinated GHG input gas, where gas g is not equal to gas i.

r = Reference data.

$$BEF_{ijg}=BEF_{ijgr}*\left[\frac{E_i}{(Mass*(1-U_{ijr})+\sum_g Mass_g BEF_{ijgr}}\right] \qquad \text{(Eq. I -31b)}$$

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} = By-product formation rate for gas i from input gas g for process type j from Table I–19 or I–20 of this subpart, as appropriate.

U_{ijr} = Process utilization rate for fluorinated GHG i, process type j, for input gas i, using Table I–19 or I–20 of 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.

* * * * *

■ 29. Amend § 98.97 by:

■ a. Revising paragraphs (b), (d)(1)(iii), (d)(3), (d)(5)(i), (d)(6) and (7), and (d)(9)(i) and (ii);

■ b. Removing and reserving paragraph (i)(1); and

■ c. Revising paragraphs (i)(5) and (9) and (k).

The revisions read as follows:

§ 98.97 Records that must be retained.

* * * * *

(b) If you use hydrocarbon-fuel-based emissions control systems 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, 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 emission control system 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, 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 emissions control system manufacturer to make the 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 after January 1, 2023, 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 of this subpart, 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 of this subpart, 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.

(ii) The site maintenance plan for abatement systems must include a defined preventative maintenance process and checklist. Preventative maintenance must include, but is not limited to, calibration of pump purge flow indicators. Pump purge flow indicators must be calibrated each time a vacuum pump is serviced or exchanged.

* * * * *

(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 of § 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.

* * * * *

(k) Annual gas consumption for each fluorinated GHG and N_2O as calculated in Equation I–11 of this subpart, 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 of this subpart, the chemical name of the GHG used, the annual consumption of the gas, and a brief description of its use.

* * * * *

■ 30. Amend § 98.98 by adding in alphabetical order a definition for ''Hydrocarbon-fuel based emission control systems'' and revising the definition of ''Operational mode'' to read as follows:

§ 98.98 Definitions.

* * * * *

Hydrocarbon-fuel based emission control systems 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 includes 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 and within the range of parameters as 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 and within the range of parameters as specified in the DRE certification documentation.

* * * * *

■ 31. Revise table I–1 to subpart I of part 98 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 EFi							
	CF_4	C_2F_6	CHF_3	$c\text{-}C_4F_8$	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.

■ 32. Redesignate table I–2 to subpart I of part 98 as table I–21 to subpart I of part 98.

■ 33. Add new table I–2 to subpart I of part 98 in numerical order 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

■ 34. Revise table I–3 to subpart I of part 98 to read as follows:

TABLE I–3 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS ($1\text{-}U_{ij}$) 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.

■ 35. Revise table I–4 to subpart I of part 98 to read as follows:

TABLE I–4 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS ($1\text{-}U_{ij}$) 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	0.18	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

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
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
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.

■ 36. Revise table I–8 to subpart I of part 98 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

■ 37. Revise table I–11 to subpart I of part 98 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 Re-mote	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

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—Continued

[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
$BCHF_3$	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.

■ 38. Revise table I–12 to subpart I of part 98 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

■ 39. Revise table I–16 to subpart I of part 98 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 (percent)
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	88
All other carbon-based fluorinated GHGs used in Semiconductor Manufacturing	60
N_2O Processes	
CVD and all other N_2O-using processes	60

■ 40. Add table I–18 to subpart I of part 98 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	0.12
$\gamma_{CH2F2,i}$	NA	NA	NA	NA	NA	NA	NA	55
$\gamma_{CH3F,i}$	NA	NA	NA	NA	NA	NA	NA	16
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
$\gamma_{CF4,i}$ (≤ 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 you use the corresponding γ in this table. For all other tools and processes, a default γ of 10 must be used.

■ 41. Add table I–19 to subpart I of part 98 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–Ui	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	0.089	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–Ui	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–Ui	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–Ui	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

■ 42. Add table I–20 to subpart I of part 98 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–Ui	0.68	0.80	0.35	0.15	0.34	0.30	0.16	0.17	0.28	0.17	0.10	NA
BCF4	NA	0.21	0.073	0.020	0.038	0.21	0.045	0.035	0.0072	0.034	0.11	NA
BC2F6	0.041	NA	0.040	0.0065	0.0064	0.18	0.030	0.038	0.0017	0.025	0.083	NA
BC4F6	0.0015	NA	0.00010	NA	0.0010	NA	0.0083	NA	NA	NA	NA	NA
BC4F8	0.0051	NA	0.00061	NA	0.0070	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
BC5F8	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
BCH2F2	0.014	NA	0.0026	NA	0.0023	NA	0.0014	0.00086	0.000020	0.000030	NA	NA
BCH3F	0.00057	NA	0.12	NA	NA	0.00073	NA	NA	0.0082	NA	NA	NA
CHAMBER CLEANING												
IN SITU PLASMA CLEANING												
1–Ui	NA	NA	NA	NA	NA	NA	NA	0.20	NA	NA	NA	NA
BCF4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC2F6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
REMOTE PLASMA CLEANING												
1–Ui	NA	NA	NA	NA	NA	0.063	NA	0.018	NA	NA	NA	NA
BCF4	NA	NA	NA	NA	NA	NA	NA	0.038	NA	NA	NA	NA
BC2F6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCHF3	NA	NA	NA	NA	NA	NA	NA	0.000059	NA	NA	NA	NA
BCH2F2	NA	NA	NA	NA	NA	NA	NA	0.0016	NA	NA	NA	NA
BCH3F	NA	NA	NA	NA	NA	NA	NA	0.0028	NA	NA	NA	NA
IN SITU THERMAL CLEANING												
1–Ui	NA	NA	NA	NA	NA	NA	NA	0.28	NA	NA	NA	NA
BCF4	NA	NA	NA	NA	NA	NA	NA	0.010	NA	NA	NA	NA
BC2F6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC3F8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Subpart N—Glass Production

■ 43. Amend § 98.146 by revising paragraphs (a)(2) and (b)(3) to read as follows:

§ 98.146 Data reporting requirements.

* * * * *

(a) * * *

(2) Annual quantity of glass produced (tons), by glass type, from each continuous glass melting furnace and from all furnaces combined.

(b) * * *

(3) Annual quantity of glass produced (tons), by glass type, from each continuous glass melting furnace and from all furnaces combined.

* * * * *

■ 44. Amend § 98.147 by revising paragraphs (a)(1) and (b)(1) to read as follows:

§ 98.147 Records that must be retained.

* * * * *

(a) * * *

(1) Monthly glass production rate for each continuous glass melting furnace, by glass type (tons).

* * * * *

(b) * * *

(1) Monthly glass production rate for each continuous glass melting furnace, by glass type (metric tons).

* * * * *

Subpart P—Hydrogen Production

■ 45. Amend § 98.163 by revising the introductory text and paragraph (b) introductory text and adding paragraph (d) to read as follows:

§ 98.163 Calculating GHG emissions.

You must calculate and report the annual CO2 emissions from each hydrogen production process unit using the procedures specified in paragraphs (a) through (d) of this section, as applicable.

* * * * *

(b) Fuel and feedstock material balance approach. Calculate and report CO2 emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b)(1) through (3) of this section. Adjust the emissions estimated using paragraphs (b)(1) through (b)(3) by correcting for non-CO_2 carbon produced, if applicable, according to paragraph (d) of this section. The carbon content and molecular weight shall be obtained from the analyses conducted in accordance with § 98.164(b)(2), (b)(3), or (b)(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.

* * * * *

(d) If carbon other than CO_2 is collected and transferred off site or if methanol is intentionally produced as a desired product, you must correct the

CO_2 emissions determined in paragraph (b) of this section to determine the net CO_2 emissions according to Equation P–4 of this section.

$$CO_{2,net} = \sum_{p=1}^{3} CO_{2,p} - \frac{44}{12}\sum_{n=1}^{k} C_{offsite,n} - \frac{44}{32}\sum_{n=1}^{k} MeOH_n \qquad \text{(Eq.P-4)}$$

$CO_{2,net}$ = Annual net CO_2 process emissions from hydrogen production unit (metric tons/yr).
$CO_{2,p}$ = Annual CO_2 process emissions arising from fuel and feedstock consumption based on fuel type ‘‘p’’ (metric tons/yr).
p = index for fuel or feedstock type; 1 indicates gaseous fuel or feedstocks; 2 indicates liquid fuel or feedstocks; and 3 indicates solid fuel or feedstocks
$C_{offsite,n}$ = Mass of carbon other than CO_2 or methanol collected from the hydrogen production unit and transferred off site, from company records for month n (metric tons carbon).
$MeOH_n$ = Mass of methanol intentionally produced as a desired product from the hydrogen production unit, from company records for month n (metric tons). If the methanol product has a 99.5 weight percent or higher purity, use the mass of methanol product produced; otherwise, you must correct that mass of product produced by the methanol purity (determined from company records) to determine the mass of methanol intentionally produced.
k = Months in the year.
44/12 = Ratio of molecular weights, CO_2 to carbon.
44/32 = Ratio of molecular weights, CO_2 to methanol.

■ 46. Amend § 98.164 by revising paragraphs (b)(2) through (4) and (b)(5) introductory text and adding paragraph (b)(5)(xix) to read as follows:

§ 98.164 Monitoring and QA/QC requirements.

* * * * *

(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) using the applicable methods in paragraph (b)(5) of this section. For non-hydrocarbon 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 determine the carbon content and the molecular weight annually using the product specification’s maximum carbon content and molecular weight rather than using the methods specified in paragraph (b)(5) of this section. 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 using the applicable methods in 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) using the applicable methods in paragraph (b)(5) of this section. For non-hydrocarbon 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 determine the carbon content annually using the product specification’s maximum carbon content rather than using the methods specified in paragraph (b)(5) of this section.

(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) using the applicable methods in paragraph (b)(5) of this section.

(5) Except as provided in paragraphs (b)(2) and (3) of this section for certain non-hydrocarbon feedstocks, 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 non-hydrocarbon fuels and feedstocks, 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.

■ 47. Amend § 98.166 by revising the introductory text and paragraphs (b)(1) and (d) 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 information specified in paragraph (a) or (b) of this section, as appropriate, and paragraphs (c) through (e) of this section:

* * * * *

(b) * * *

(1) Unit identification number and annual CO_2 emissions (determined in accordance with § 98.163(b) or (d), as applicable).

* * * * *

(d) Annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (metric tons carbon), excluding methanol, for each process unit.

* * * * *

■ 48. Amend § 98.167 by revising paragraph (b) and paragraph (e) introductory text and adding paragraphs (e)(13) and (14) to read as follows:

§ 98.167 Records that must be retained.

* * * * *

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records of all analyses and calculations conducted to determine the values reported in § 98.166(b) through (e).

* * * * *

(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 (14) of this section.

Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (e)(1) through (14) of this section for each hydrogen production unit.

* * * * *

(13) Monthly mass of carbon other than CO_2 or methanol collected and transferred off site (metric tons carbon) (Equation P–4).

(14) Monthly mass of methanol intentionally produced as a desired product (metric tons) (Equation P–4).

Subpart Q—Iron and Steel Production

■ 49. 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) * * *

$$CO_2 = \frac{44}{12} * \left[(Iron) * (C_{iron}) + (Scrap) * (C_{scrap}) + (Flux) * (C_{Flux}) + (Electrode) * (C_{Electrode}) + (Carbon) * (C_{Carbon}) - (Steel) * (C_{Steel}) + (F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 - (Slag) * (C_{Slag}) - (R) * (C_R)\right] \quad \text{(Eq. Q-5)}$$

* * * * *

■ 50. 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 (b)(2)(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.

* * * * *

■ 51. Amend § 98.176 by revising paragraphs (e)(2) and (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

■ 52. Amend § 98.193 by revising paragraph (b)(2)(iv) to read as follows:

§ 98.193 Calculating GHG emissions.

* * * * *

(b) * * *

(2) * * *

(iv) You must calculate annual net CO_2 process emissions for all lime kilns using Equation S–4 of this section:

$$E_{CO2,net} = \sum_{i=1}^{t}\sum_{n=1}^{12}\left(EF_{LIME,i,n} * M_{LIME,i,n}\right) + \sum_{i=1}^{b}\sum_{n=1}^{12}\left(EF_{LKD,i,n} * M_{LKD,i,n}\right) + \sum_{i=1}^{z} E_{waste,i} - \sum_{n=1}^{12} E_{product,n} \quad \text{(Eq. S-4)}$$

Where:

$E_{CO2,\ net}$ = Annual net CO_2 process emissions from lime production from all lime kilns (metric tons/year).

$EF_{LIME,i,n}$ = Emission factor for lime type i produced, in calendar month n (metric tons CO_2/ton lime) from Equation S–1 of this section.

$M_{LIME,i,n}$ = Weight or mass of lime type i produced in calendar month n (tons).

$EF_{LKD,i,n}$ = Emission factor of calcined byproducts or wastes sold for lime type i in calendar month n, (metric tons CO_2/ton byproduct or waste) from Equation S–2 of this section.

$M_{LKD,i,n}$ = Monthly weight or mass of calcined byproducts or waste sold (such as lime kiln dust, LKD) for lime type i in calendar month n (tons).

$E_{waste,i}$ = Annual CO_2 emissions for calcined lime byproduct or waste type i that is not sold (metric tons CO_2) from Equation S–3 of this section.

$E_{product,n}$ = Monthly amount of CO_2 from lime production that is captured for use in all on-site processes in calendar month n, as described in § 98.196(b)(17) (metric tons).

t = Number of lime types produced

b = Number of calcined byproducts or wastes that are sold.

z = Number of calcined byproducts or wastes that are not sold.

* * * * *

■ 53. Amend § 98.196 by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraphs (a)(9) through (14);

■ c. Revising paragraphs (b) introductory text, (b)(1), (b)(17) introductory text, and (b)(17)(i); 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.

(1) Annual net CO_2 process emissions from all lime kilns combined (metric tons).

* * * * *

(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.

* * * * *

(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.

■ 54. Amend § 98.197 by revising paragraph (c) introductory text and adding paragraph (c)(10) to read as follows:

§ 98.197 Records that must be retained.

* * * * *

(c) 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 (c)(1) through (10) of this section. Retention of this file satisfies the recordkeeping requirement for the data in paragraphs (c)(1) through (10) of this section.

* * * * *

(10) Monthly amount of CO_2 from lime production that is captured for use in all on-site processes, as described in § 98.196(b)(17) (metric tons) (Equation S–4).

Subpart W—Petroleum and Natural Gas Systems

■ 55. Amend § 98.230 by revising paragraph (a)(3) to read as follows:

§ 98.230 Definition of the source category.

(a) * * *

(3) *Onshore natural gas processing.* Natural gas processing means the forced extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. Natural gas processing does not include a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant.

* * * * *

■ 56. Amend § 98.232 by:
■ a. Revising paragraphs (b) and (c)(21);
■ b. Adding paragraph (c)(23);
■ c. Revising paragraph (d)(7);
■ d. Adding paragraphs (d)(8) and (9);
■ e. Revising paragraph (e)(8);
■ f. Adding paragraph (e)(9);
■ g. Revising paragraphs (f)(6) and (8);
■ h. Adding paragraph (f)(9);
■ i. Revising paragraphs (g)(6) and (7);
■ j. Adding paragraph (g)(8);
■ k. Revising paragraphs (h)(7) and (8);
■ l. Adding paragraphs (h)(9) and (10) and (i)(8);
■ m. Revising paragraph (j)(10);
■ n. Adding paragraph (j)(13); and
■ o. Revising paragraph (m).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

* * * * *

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEM in compliance with 30 CFR 550.302 through 304 and CO_2 and CH_4 emissions from other large release events. Offshore platforms do not need to report portable emissions.

(c) * * *

(21) Equipment leaks listed in paragraph (c)(21)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, acid gas removal units, dehydrators, heater treaters, and storage vessels.

* * * * *

(23) Other large release events.

(d) * * *

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters, and equipment leaks from all other components in gas service that either are subject to equipment leak standards for processing plants in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Natural gas pneumatic device venting.

(9) Other large release events.

(e) * * *

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, or that you elect to survey using a leak detection method described in § 98.234(a). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel.

(9) Other large release events.

(f) * * *

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

* * * * *

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a, of

this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Other large release events.

(g) * * *

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Other large release events.

(h) * * *

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in 40 CFR part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Acid gas removal vents.

(10) Other large release events.

(i) * * *

(8) Other large release events.

(j) * * *

(10) Equipment leaks listed in paragraph (j)(10)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, acid gas removal units, dehydrators, heater treaters, and storage vessels.

* * * * *

(13) Other large release events.

* * * * *

(m) For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks and CO_2 and CH_4 emissions from other large release events.

■ 57. Amend § 98.233 by:

■ a. Revising paragraphs (a), (c), (d) introductory text, and (d)(4)(vi);

■ b. Adding paragraph (d)(12);

■ c. Revising paragraphs (e) introductory text, (e)(1) introductory text; (e)(1)(x), and (e)(2) introductory text;

■ d. Revising parameter ''Count'' of Equation W–5 in paragraph (e)(2);

■ e. Removing and reserving paragraph (e)(3);

■ f. Removing paragraph (e)(4);

■ g. Redesignating paragraphs (e)(5) and (6) as (e)(4) and (5), respectively;

■ h. Revising newly redesignated paragraphs (e)(4) and (5) and paragraphs (g)(4), (h)(2), (i) introductory text, and (i)(2) introductory text;

■ i. Revising parameters ''T_a'' and ''P_a'' of Equation W–14A in paragraph (i)(2)(i);

■ j. Revising parameters ''$T_{a,p}$'', ''$P_{a,b,p}$'', and ''$P_{a,e,p}$'' of Equation W–14B in paragraph (i)(2)(i);

■ k. Adding paragraph (i)(2)(iv);

■ l. Revising paragraphs (j) introductory text, (j)(1) introductory text, (j)(1)(iii), (iv), and (vii), and (j)(2);

■ m. Revising parameter ''Count'' of Equation W–15 in paragraph (j)(3);

■ n. Revising paragraphs (j)(4) through (6), (k)(5), (l)(6), and (m)(3) introductory text;

■ o. Revising parameters ''$V_{p,q}$'' and ''$SG_{p,q}$'' of Equation W–18 in paragraph (m)(3);

■ p. Revising paragraphs (m)(5), (n) introductory text, (n)(1), (n)(2) introductory text, and (n)(5);

■ q. Removing and reserving paragraph (n)(9);

■ r. Revising paragraphs (o) introductory text, (o)(1)(i) introductory text, (o)(1)(i)(A) through (C), (o)(2) introductory text, (o)(2)(i) introductory text, and (o)(2)(ii);

■ s. Adding paragraph (o)(2)(iii);

■ t. Removing and reserving paragraph (o)(4)(ii)(D);

■ u. Revising paragraphs (o)(4)(ii)(E) and (o)(6)(i) introductory text;

■ v. Revising parameter ''m'' of Equation W–21 in paragraph (o)(6)(i);

■ w. Revising paragraph (o)(6)(ii) introductory text;

■ x. Revising parameter ''m'' of Equation W–22 in paragraph (o)(6)(ii);

■ y. Revising paragraph (o)(6)(iii) introductory text;

■ z. Revising parameter ''m'' of Equation W–23 in paragraph (o)(6)(iii);

■ aa. Revising parameter ''T_g'' of Equation W–24B in paragraph (o)(8);

■ bb. Revising paragraph (o)(10) introductory text;

■ cc. Revising parameter ''Count'' of Equation W–25 in paragraph (o)(10);

■ dd. Revising paragraphs (p) introductory text, (p)(1)(i), (p)(2) introductory text, (p)(2)(ii) introductory text, (p)(2)(ii)(C), (p)(2)(iii)(A), and (p)(4)(ii)(C);

■ ee. Removing and reserving paragraph (p)(4)(ii)(D);

■ ff. Revising paragraphs (p)(4)(ii)(E), (p)(6)(ii) introductory text, (p)(6)(iii) introductory text, and (p)(10) introductory text;

■ gg. Revising parameter ''Count'' of Equation W–29D in paragraph (p)(10);

■ hh. Revising paragraphs (q) introductory text, (q)(1), and (q)(2) introductory text;

■ ii. Revising parameter ''$EF_{s,p}$'' of Equation W–30 in paragraph (q)(2) introductory text;

■ jj. Revising paragraphs (q)(2)(i), (iii), (v), (x), and (xi);

■ kk. Adding paragraph (q)(3);

■ ll. Revising paragraph (r) introductory text;

■ mm. Revising parameters ''$E_{s,e,I}$,'' ''$E_{s,MR,I}$,'' ''$Count_e$,'' ''$Count_{MR}$,'' and ''$EF_{s,e}$'' of Equations W–32A and W–32B in paragraph (r) introductory text;

■ nn. Revising paragraphs (r)(2), (r)(6)(i) and (ii), and (s);

■ oo. Revising parameter “Z_a” of Equation W–34 in paragraph (t)(2);

■ pp. Removing the unnumbered text “You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.” after parameter “Z_a” of Equation W–34 in paragraph (t)(2); and

■ qq. Revising paragraphs (u)(2)(ii), (y), and (z).

The revisions and additions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) *Natural gas pneumatic device venting.* For all natural gas pneumatic devices at onshore natural gas processing facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, use methods specified in paragraphs (a)(1) through (5) of this section to calculate CH_4 and CO_2 emissions. For all continuous high bleed and continuous low bleed natural gas pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility, use methods specified in paragraphs (a)(1) through (5) of this section to calculate CH_4 and CO_2 emissions. For intermittent bleed natural gas pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, use the methods specified in paragraph (a)(6) of this section to calculate CH_4 and CO_2 emissions from those pneumatic devices. For intermittent bleed natural gas pneumatic devices at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are not subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may either elect to monitor your intermittent bleed natural gas pneumatic devices at least annually following the methods specified in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, as applicable, and use the methods specified in paragraph (a)(6) of this section to calculate CH_4 and CO_2 emissions from your natural gas intermittent bleed pneumatic devices or use the methods specified in paragraphs (a)(1) through (5) of this section to calculate CH_4 and CO_2 emissions from your natural gas intermittent bleed pneumatic devices.

(1) Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1A of this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1A)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types “t” (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type “t” (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1) or (a)(2) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type “t” listed in Tables W–1A, W–2B, W–3B, and W–4B to this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas processing, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i) through (iv) of this section.

T_t = Average estimated number of hours in the operating year the devices, of each type “t”, were in service (*i.e.,* supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.

(2) For all industry segments, determine “$Count_t$” for Equation W–1A of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the devices, except as specified in paragraph (a)(3) of this section. The reported number of devices must represent the total number of devices for the reporting year.

(3) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine “$Count_t$” for Equation W–1A of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine “$Count_t$” for Equation W–1A for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

(4) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(6) Calculate CH_4 and CO_2 volumetric emissions using Equation W–1B of this section from natural gas intermittent bleed pneumatic devices that are monitored according to the requirements in this paragraph (a)(6).

$$E_i = GHG_i * \left[\left(24.1 * \sum_{z=1}^{x} T_z\right) + \left(0.3 * Count * T_{avg}\right)\right] \qquad \text{(Eq. W-1B)}$$

Where:

E_i = Annual total volumetric emissions of GHG_i from natural gas intermittent bleed pneumatic devices in standard cubic feet.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in natural gas supplied to the intermittent bleed device as defined in paragraph (u)(2) of this section.

x = Total number of intermittent bleed devices detected as malfunctioning in any pneumatic device monitoring survey during the year. A component found as malfunctioning in two or more surveys during the year is counted as one malfunctioning component.

24.1 = Whole gas emission factor for malfunctioning intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device.

T_z = The total time the surveyed pneumatic device "z" was in service (*i.e.,* supplied with natural gas) and assumed to be leaking, in hours. If one pneumatic device monitoring survey is conducted in the calendar year, assume the device found malfunctioning was malfunctioning for the entire calendar year. If multiple pneumatic device monitoring surveys are conducted in the calendar year, assume a device found malfunctioning in the first survey was malfunctioning since the beginning of the year until the date of the survey; assume a device found malfunctioning in the last survey of the year was malfunctioning from the preceding survey through the end of the year; assume a device found malfunctioning in a survey between the first and last surveys of the year was malfunctioning since the preceding survey until the date of the survey; and sum times for all malfunctioning periods.

0.3 = Whole gas emission factor for properly operating intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour.

Count = Total number of intermittent bleed devices that were never observed to be malfunctioning during any monitoring survey during the year.

T_{avg} = The average time the pneumatic devices that were never observed to be malfunctioning during any monitoring survey were in service (*i.e.,* supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.

(i) You must conduct pneumatic device monitoring surveys using the methods in either paragraph (a)(6)(i) or (ii) of this paragraph.

(A) For intermittent bleed natural gas pneumatic devices that are subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an approved state plan or Federal plan in part 62 of this chapter, as applicable, you must use the methods specified in the applicable standard.

(B) For intermittent bleed natural gas pneumatic devices that are not subject to monitoring requirements in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and that you elect to monitor, you must use the methods specified in part 60, subpart OOOOb of this chapter.

(ii) You must conduct at least one complete pneumatic device monitoring survey in a calendar year. If you conduct multiple complete pneumatic device monitoring surveys in a calendar year, you must use the results from each complete pneumatic device monitoring survey when calculating emissions using Equation W–1B.

(iii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

* * * * *

(c) *Natural gas driven pneumatic pump venting.* Calculate emissions from natural gas driven pneumatic pumps venting directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section. Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraph (c)(3) of this section. You do not have to calculate emissions from natural gas driven pneumatic pumps covered in paragraph (e) of this section under this paragraph (c).

(1) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-2)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps that vented directly to the atmosphere.

EF = Population emission factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W–1A of this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

T = Average estimated number of hours in the operating year the pumps that vented directly to the atmosphere were in service (*i.e.,* supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours for pumps that only vented directly to the atmosphere.

(2) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(3) Calculate emissions from natural gas driven pneumatic pumps routed to flares, combustion, or vapor recovery systems as specified in paragraph (c)(3)(i) or (ii) of this section, as applicable. If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then calculate emissions from the time the pump vents directly to the atmosphere as specified in paragraphs (c)(1) and (2) of this section and calculate emissions from the time the pump was routed to a flare or combustion as specified in paragraphs (c)(3)(i) and (ii) of this section, as applicable. For emissions that are collected in a vapor recovery system that is not routed to combustion, paragraphs (c)(1) and (2) and (c)(3)(i) and (ii) do not apply and no emissions calculations are required.

(i) If any natural gas driven pneumatic pumps were routed to a flare, you must calculate CH_4, CO_2, and N_2O emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to natural gas driven pneumatic pumps from the flare.

(ii) If emissions from any natural gas driven pneumatic pumps were routed to combustion, you must calculate emissions for the combustion equipment as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z).

(d) *Acid gas removal (AGR) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or emitted through an engine (*e.g.,* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant, using any of the calculation methods described in paragraphs (d)(1) through (4) of this section, and also comply with paragraphs (d)(5) through (11), as applicable. For AGR emissions that are routed to a flare, calculate the flared emissions as specified in paragraph (d)(12) of this section.

* * * * *

(4) * * *

(vi) Solvent type, pressure, temperature, circulation rate, and composition.

* * * * *

(12) For AGR vents routed to a flare, calculate CO_2 emissions from the AGR as specified in paragraph (d)(12)(i) or (ii) of this section, as applicable.

(i) For emissions from an AGR unit that are routed to a dedicated flare, or if the emissions from the AGR unit are comingled with emissions from any other source types for routing to a flare and you do not continuously measure either flow or composition of the comingled gas stream, then calculate CO_2 emissions from the AGR using a method specified in paragraph (d)(1) through (4) of this section, as applicable. You must also incorporate your AGR data into the parameters V_s and X_{CO2} in Equation W–20 to account for the AGR portion of the total flared CO_2 emissions for all miscellaneous flared sources as described in paragraphs (n)(1) and (2) of this section.

(ii) For emissions from an AGR unit that are comingled with emissions from any other source types for routing to a flare and you continuously measure flow and/or composition of the comingled gas stream, then calculate total emissions from all miscellaneous flared sources (which includes AGRs) for the flare(s) to which the AGR emissions are routed using the procedures specified in paragraphs (n)(1) through (8) of this section. Use site-specific engineering estimates based on best available data to calculate the portion of the total flared CO_2 emissions from the miscellaneous flared sources that entered the flare from the AGR. Report the calculated portion of the total flared CO_2 emissions that entered the flare from the AGR as CO_2 emissions from the AGR as specified in § 98.236(d)(1)(v). Subtract this amount of CO_2 from the total flared CO_2 and report the remainder as CO_2 from miscellaneous flared sources as specified in § 98.236(n)(1)(xi).

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4 and CO_2 emissions using the applicable calculation methods described in paragraphs (e)(1) through (5) of this section. If emissions from dehydrator vents are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (e)(4) of this section. If emissions from dehydrator vents are routed to a flare or regenerator firebox/fire tubes, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(5) of this section.

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day by using a software program, such as AspenTech HYSYS® or GRI–GLYCalc™, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas, and a gas injection pump or gas assist pump. Emissions must be modeled from both the still vent and, if applicable, the flash tank vent. The following parameters must be determined by engineering estimate based on best available data and must be used at a minimum to characterize emissions from dehydrators:

* * * * *

(x) Wet natural gas temperature and pressure at the absorber inlet.

* * * * *

(2) *Calculation Method 2.* Calculate annual volumetric emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day using Equation W–5 of this section, and then calculate the collective CH_4 and CO_2 mass emissions from the volumetric emissions using the procedures in paragraph (v) of this section:

* * * * *

Count = Total number of glycol dehydrators that have an annual average daily natural gas throughput that is greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day.

* * * * *

(4) If the dehydrator unit has vapor recovery, calculate annual emissions as specified in paragraphs (e)(4)(i) and (ii) of this section.

(i) Adjust the emissions estimated in paragraphs (e)(1) and (2) of this section, as applicable, downward by the magnitude of emissions recovered using a vapor recovery system and by the amount of emissions routed to flares or regenerator firebox/fire tubes as determined by engineering estimate based on best available data. Report unrecovered emissions that are not routed to flares or regenerator fireboxes/fire tubes as emissions vented directly to the atmosphere.

(ii) If unrecovered emissions from the dehydrator are routed to flares or regenerator fireboxes/fire tubes, use the calculation method of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent. Use the volume routed to the flares or regenerator fireboxes/fire tubes and the dehydrator vent gas composition as determined using either engineering estimates based on best available data or the procedures specified in paragraph (u)(2) of this section, as applicable. Report unrecovered emissions that are routed to flares or regenerator fireboxes/fire tubes as flared emissions from dehydrators.

(5) If any dehydrator vent streams are routed to a flare or regenerator firebox/fire tubes, calculate emissions from these devices attributable to dehydrators as specified in paragraphs (e)(5)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (e)(5)(v) of this section instead of the provisions of paragraphs (e)(5)(i) through (iv) of this section.

(i) Determine the volume of gas from the dehydrator(s) to each flare using any of the methods specified in paragraph (e)(5)(i)(A) or (B) of this section. You are not required to use the same method for all dehydrator streams.

(A) Use the vented volume as determined in paragraphs (e)(1) through (4) of this section.

(B) Measure the flow from the dehydrator(s) to the flare or regenerator firebox/fire tubes using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from multiple dehydrators or from dehydrators and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from each large dehydrator or from all small dehydrators combined.

(ii) Except as specified in paragraph (e)(5)(iii) of this section, determine composition of the gas from the dehydrator(s) to each flare or regenerator firebox/fire tubes using any of the methods specified in paragraphs (e)(5)(ii)(A) through (C) of this section. You are not required to use the same method for all dehydrator streams.

(A) Use the gas composition as determined in paragraphs (e)(1) through (4) of this section.

(B) Measure the composition of the gas from the dehydrator(s) to the flare or regenerator firebox/fire tubes using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from multiple dehydrators, assume the measured composition applies to all dehydrators that route gas through the manifold.

(C) Measure the composition of the total gas to the flare or regenerator firebox/fire tubes using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from dehydrators and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from each large dehydrator or from all small dehydrators combined.

(iii) If you continuously measure flow in accordance with paragraph (e)(5)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (e)(5)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate dehydrator emissions from flares or regenerator firebox/fire tubes.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual dehydrator emissions from flares or regenerator firebox/fire tubes.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from multiple dehydrators or from both dehydrators and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from each large dehydrator and from all small dehydrators combined.

* * * * *

(g) * * *

(4) If any streams from well completions and workovers with hydraulic fracturing are flared, calculate annual emissions as specified in paragraphs (g)(4)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (g)(4)(v) of this section instead of the provisions of paragraphs (g)(4)(i) through (iv) of this section.

(i) Determine the volume of gas from well completions and workovers with hydraulic fracturing routed to each flare using any of the methods specified in paragraph (g)(4)(i)(A) or (B) of this section. You are not required to use the same method for all streams.

(A) Use the volume from gas venting to the atmosphere during well completions and workovers with hydraulic fracturing as determined in paragraph (g) of this section. Subtract the estimated amount vented to the atmosphere, if any, from this total volume.

(B) Measure the flow from well completions and workovers with hydraulic fracturing to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from well completions and workovers with hydraulic fracturing and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from well completions and workovers with hydraulic fracturing.

(ii) Except as specified in paragraph (g)(4)(iii) of this section, determine composition of the gas from well completions and workovers with hydraulic fracturing to each flare using any of the methods specified in paragraphs (g)(4)(ii)(A) through (C) of this section. You are not required to use the same method for all streams.

(A) Use the gas composition as determined in paragraph (g)(3) of this section.

(B) Measure the composition of the gas from well completions and workovers with hydraulic fracturing to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from well completions and workovers with hydraulic fracturing, assume the measured composition applies to all completions and workovers with hydraulic fracturing that route gas through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from well completions and workovers with hydraulic fracturing and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from each well completions and workovers with hydraulic fracturing.

(iii) If you continuously measure flow in accordance with paragraph (g)(4)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (g)(4)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate well completion and workover from hydraulic fracturing emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual emissions for the portion of gas flared during well completions and workovers using hydraulic fracturing.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from multiple well completions and workovers with hydraulic fracturing or from both well completions and workovers with hydraulic fracturing and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from well completions and workovers with hydraulic fracturing.

(h) * * *

(2) If any streams from gas well completions and workovers without hydraulic fracturing are flared, calculate annual emissions of CH_4, CO_2, and N_2O as specified in paragraphs (h)(2)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (h)(2)(v) of this section instead of the provisions of paragraphs (h)(2)(i) through (iv) of this section.

(i) Determine the volume of gas from well completions and workovers without hydraulic fracturing routed to each flare using any of the methods specified in paragraph (h)(2)(i)(A) or (B) of this section. You are not required to use the same method for all streams.

(A) Use the gas well venting volume during well completions and workovers without hydraulic fracturing that are flared as determined using the methods specified in paragraphs (h) and (h)(1) of this section.

(B) Measure the flow from well completions and workovers without hydraulic fracturing to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from well completions and workovers without hydraulic fracturing and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from well completions and workovers without hydraulic fracturing.

(ii) Determine composition of the gas from well completions and workovers without hydraulic fracturing to each flare using any of the methods specified in paragraphs (h)(2)(ii)(A) through (C) of this section. You are not required to use the same method for all streams.

(A) Use the gas composition as determined in paragraphs (h) introductory text and (h)(1) of this section.

(B) Measure the composition of the gas from well completions and workovers without hydraulic fracturing to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from well completions and workovers without hydraulic fracturing, assume the measured composition applies to all completions and workovers without hydraulic fracturing that route gas through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from well completions and workovers without hydraulic fracturing and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from each well completions and workovers without hydraulic fracturing.

(iii) If you continuously measure flow in accordance with paragraph (h)(2)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (h)(2)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate well completion and workover from hydraulic fracturing emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual emissions from the flare for gas well venting to a flare during completions and workovers without hydraulic fracturing.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from multiple well completions and workovers without hydraulic fracturing or from both well completions and workovers without hydraulic fracturing and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from well completions and workovers without hydraulic fracturing.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from the depressurization of equipment to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance as specified in either paragraph (i)(2) or (3) of this section. You may use the method in paragraph (i)(2) of this section for some blowdown vent stacks at your facility and the method in paragraph (i)(3) of this section for other blowdown vent stacks at your facility. Equipment with a unique physical volume of less than 50 cubic feet as determined in paragraph (i)(1) of this section are not subject to the requirements in paragraphs (i)(2) through (4) of this section. The requirements in this paragraph (i) do not apply to blowdown vent stack emissions from depressurizing to a flare, over-pressure relief, operating pressure control venting, and blowdown of non-GHG gases.

* * * * *

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) of this section or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. Categorize equipment and event types for each industry segment as specified in paragraph (i)(2)(iv) of this section.

(i) * * *

T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the pressure.

* * * * *

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown ‘‘p’’. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown ‘‘p’’. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the pressure at the beginning of the blowdown.

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown ‘‘p’’; 0 if blowdown volume is purged using non-GHG gases. For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, engineering estimates based on best available information may be used to determine the pressure at the end of the blowdown.

* * * * *

(iv) Categorize blowdown vent stack emission events as specified in paragraphs (i)(2)(iv)(A) and (B) of this section, as applicable.

(A) For the onshore natural gas processing, transmission compression, LNG import and export equipment, and onshore petroleum and natural gas gathering and boosting industry segments, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* physical volumes associated with piping for which the entire physical volume is located within the facility boundary), pipeline venting (*i.e.,* physical volumes associated with pipelines for which a portion of the physical volume is located outside the facility boundary and the remainder, including the blowdown vent stack, is located within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event.

(B) For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

* * * * *

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of hydrocarbon liquids greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2 for separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last gas-liquid separator or non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the hydrocarbon liquids from the separator or non-separator equipment enter an atmospheric pressure storage tank. The following parameters must be determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from liquid transferred to tanks:

* * * * *

(iii) Sales oil or stabilized hydrocarbon liquids API gravity.

(iv) Sales oil or stabilized hydrocarbon liquids production rate.

* * * * *

(vii) Separator or non-separator equipment hydrocarbon liquids composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment hydrocarbon liquid composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment hydrocarbon liquids composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment hydrocarbon liquids in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for hydrocarbon liquids composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2.* Calculate annual CH_4 and $COCO_2$ emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators with annual average daily throughput of hydrocarbon liquids greater than or equal to 10 barrels per day. Calculate annual CH_4 and $COCO_2$ emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily hydrocarbon liquids production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and $COCO_2$ emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

(i) *Flow to storage tank after passing through a separator.* Assume that all of the CH_4 and $COCO_2$ in solution at separator temperature and pressure is emitted from hydrocarbon liquids sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator hydrocarbon liquids composition at separator pressure and temperature.

(ii) *Flow to storage tank direct from wells.* Calculate CH_4 and $COCO_2$ emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production hydrocarbon liquids and gas compositions are available through a previous analysis, select the latest available analysis that is representative of produced hydrocarbon liquids and gas from the sub-basin category and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If well production hydrocarbon liquids and gas compositions are not available, use default hydrocarbon liquids and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the well production gas/oil ratio and API gravity and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(iii) Flow to storage tank direct from non-separator equipment. Calculate CH4 and CO2 emissions using either of the methods in paragraph (j)(2)(iii)(A) or (B) of this section.

(A) If other non-separator equipment hydrocarbon liquids and gas compositions are available through a previous analysis, select the latest available analysis that is representative of hydrocarbon liquids and gas from non-separator equipment in the same county and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment hydrocarbon liquids and gas compositions are not available, use default hydrocarbon liquids and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH4 and CO2 in both hydrocarbon liquids and gas are emitted from the tank.

(3) * * *

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed hydrocarbon liquids directly to the storage tank.

* * * * *

(4) If the storage tank receiving your hydrocarbon liquids has a vapor recovery system, calculate annual emissions from storage tanks as specified in paragraphs (j)(4)(i) and (ii) of this section.

(i) Using engineering estimates based on best available data, determine the portion of the total emissions estimated in paragraphs (j)(1) through (3) of this section that is recovered using a vapor recovery system. You must take into account periods with reduced capture efficiency of the vapor recovery system (*e.g.,* when a thief hatch is open or not properly seated) when calculating emissions recovered.

(ii) Determine total emissions not recovered by a vapor recovery system as specified in paragraphs (j)(4)(ii)(A) and (B) of this section.

(A) Adjust the emissions estimated in paragraphs (j)(1) through (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system and by the amount of emissions routed to flares. Unrecovered emissions may include, but are not limited to, emissions during periods when the vapor recovery system is not operating, losses from the tank when the vapor recovery system is not operating and the tank is connected to a flare, and losses from the tank during periods when the vapor recovery system is operating. These losses may include, but are not limited to, emissions due to open or unseated thief hatches. Report unrecovered emissions that are not routed to flares as emissions vented directly to the atmosphere.

(B) If unrecovered emissions from atmospheric tanks are routed to flares, determine the volume of gas routed to flares, calculate annual emissions from flares as specified in paragraphs (j)(5)(i) through (iii) of this section, and report as flared emissions from atmospheric tanks.

(5) If the storage tank receiving your hydrocarbon liquids has a flare(s), calculate annual flared emissions from storage tanks as specified in paragraphs (j)(5)(i) through (v) of this section and calculate emissions vented directly to the atmosphere as specified in paragraph (j)(5)(vi) of this section. For atmospheric tanks with emissions calculated using Calculation Method 3 in paragraph (j)(3) of this section, this paragraph (j)(5) only applies when at least half of the hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks are directed to atmospheric tanks that used flares to control emissions. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (j)(5)(v) of this section instead of the provisions of paragraphs (j)(5)(i) through (iv) of this section.

(i) Estimate the volume routed to the flare using any of the methods specified in paragraph (j)(5)(i)(A) or (B) of this section. You are not required to use the same method for all storage tanks.

(A) If unrecovered emissions from the storage tank are calculated in accordance with paragraph (j)(4) of this section, then determine the volume of the unrecovered emissions routed to flares based on best available data. If no emissions from the storage tank are routed to vapor recovery, then use the storage tank emissions volume as determined in paragraphs (j)(1) through (3) of this section, except that you must also adjust this total volume of emissions downward by the estimated portion of the total volume that is not routed to the flare (*e.g.,* when the flare is bypassed or when a thief hatch is open or not properly seated). Estimate the volume of the emissions not routed to flares based on best available data.

(B) Measure the flow from the storage tank(s) to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from storage tanks and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from each storage tank.

(ii) Except as specified in paragraph (j)(5)(iii) of this section, determine the composition of the gas from the storage tanks routed to the flare using any of the methods specified in paragraphs (j)(5)(ii)(A) through (C) of this section. You are not required to use the same method for all storage tanks.

(A) If you use Calculation Method 1 or Calculation Method 2, use your gas composition as determined in paragraphs (j)(1) and (2) of this section. If you use Calculation Method 3 in paragraph (j)(3) of this section, determine the gas composition using either engineering estimates based on best available data or the procedures specified in paragraph (u)(2)(i) of this section.

(B) Measure the composition of the gas from the storage tanks to the flare using a continuous gas composition analyzer. If the measured composition is in a manifold that combines streams only from multiple storage tanks, assume the measured composition applies to all storage tanks that route gas through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from storage tanks and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from storage tanks.

(iii) If you continuously measure flow in accordance with paragraph (j)(5)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (j)(5)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate storage tank emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section with the volume and composition determined according to paragraphs (j)(5)(i) and (ii) of this section to determine storage tank emissions from the flare.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from both storage tanks and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from storage tanks.

(vi) For storage tanks with no vapor recovery system, if the volume routed to the flare as determined in paragraph (j)(5)(i)(A) or (B) of this section is less than the total volume of emissions from the tank as estimated in paragraphs (j)(1) through (3) of this section, then use the volume not sent to the flare to calculate emissions of flash gas vented directly to the atmosphere from the storage tank.

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i,dv} = CF_{dv} \times \frac{E_{s,i}}{8{,}760} \times T_{dv} \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i,dv}$ = Annual volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet from storage tanks that resulted from the dump valve on the gas-liquid separator not closing properly.

$E_{s,i}$ = Annual volumetric GHG emissions (either CO_2 or CH_4) as determined in paragraphs (j)(1) and (2) and, if applicable, (j)(4) and (5) of this section, in standard cubic feet per year, from storage tanks with dump valves on an associated gas-liquid separator that did not close properly.

T_{dv} = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_{dv} based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_{dv} = Correction factor for tank emissions for time period T_{dv} is 2.87 for crude oil production. Correction factor for tank emissions for time period T_{dv} is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

* * * * *

(k) * * *

(5) If any transmission storage tanks are routed to flares, calculate emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to transmission tanks from the flare. If the volume to the flare is not continuously measured for the duration of time that flaring occurred, then conduct an annual leak measurement as specified in paragraph (k)(1)(ii) or (iv) of this section. If a leak is detected, quantify the leak in accordance with paragraph (k)(2)(i) or (ii) of this section and determine the time leaking as specified in paragraph (k)(3) of this section. Use these data when estimating total flow to the flare in accordance with paragraph (n)(1) of this section.

(l) * * *

(6) If any emissions from well testing are routed to a flare, calculate flared emissions from well testing as specified in paragraphs (l)(6)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (l)(6)(v) of this section instead of the provisions of paragraphs (l)(6)(i) through (iv) of this section.

(i) Determine the volume of gas from well testing to each flare using any of the methods specified in paragraph (l)(6)(i)(A) or (B) of this section. You are not required to use the same method for all well testing.

(A) Use the well testing emissions volume as determined in paragraphs (l)(1) through (4) of this section.

(B) Measure the flow from well testing to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from well testing and other sources, use engineering calculations based on process knowledge and best available data to estimate the portion(s) of the total flow (in scf) from well testing.

(ii) Except as specified in paragraph (l)(6)(iii) of this section, determine composition of the gas from well testing to each flare using any of the methods specified in paragraphs (l)(6)(ii)(A) through (C) of this section. You are not required to use the same method for all well testing.

(A) Use the gas composition as determined in paragraphs (l)(1) through (4) of this section.

(B) Measure the composition of gas from well testing to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines streams only from testing of multiple wells, assume the measured composition applies to all well testing gas routed through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines flow from well testing and other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the flow from well testing.

(iii) If you continuously measure flow in accordance with paragraph (l)(6)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (l)(6)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate well testing emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to determine annual well testing emissions from the flare.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives gas from both well testing and other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from well testing.

(m) * * *

(3) Estimate venting emissions using Equation W–18 of this section. Alternatively, if you measure the flow to a vent using a continuous flow measurement device, you must use the measured flow volumes to calculate vented associated gas emissions.

* * * * *

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year only during time periods in which associated gas was vented or flared.

$SG_{p,q}$ = Volume of associated gas sent to sales, for well p in sub-basin q, in standard cubic feet of gas in the calendar year only during time periods in which associated gas was vented or flared.

* * * * *

(5) Calculate flared associated natural gas emissions as specified in paragraphs (m)(5)(i) through (v) of this section. If you operate a CEMS to monitor the emissions from the flare in accordance

with paragraph (n)(8) of this section, calculate emissions as specified in paragraph (m)(5)(v) of this section instead of the provisions of paragraphs (m)(5)(i) through (iv) of this section.

(i) Determine the volume of associated gas to each flare using any of the methods specified in paragraph (m)(5)(i)(A) or (B) of this section. You are not required to use the same method for all associated gas streams.

(A) Use the associated natural gas volume as determined in paragraphs (m)(1) through (4) of this section.

(B) Measure the flow of associated gas to the flare using a continuous flow measurement device. If the measured volume is in a manifold that combines flow from multiple associated gas streams or from associated gas streams and other sources, use engineering calculations based on process knowledge and best available data to estimate the portions of the total flow (in scf) that is associated gas.

(ii) Except as specified in paragraph (m)(5)(iii) of this section, determine composition of the associated gas to each flare using any of the methods specified in paragraphs (m)(5)(ii)(A) through (C) of this section. You are not required to use the same method for all associated gas streams.

(A) Use the associated gas composition as determined in paragraphs (m)(1) through (4) of this section.

(B) Measure the composition of the associated gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines only associated gas streams, assume the measured composition applies to all associated gas that is routed through the manifold.

(C) Measure the composition of the total gas to the flare using a continuous composition analyzer. If the measured composition is in a manifold that combines both associated gas and gas from other sources, use engineering calculations based on available sampling data for other sources, process knowledge, and best available data to estimate the composition of the associated gas in the combined stream.

(iii) If you continuously measure flow in accordance with paragraph (m)(5)(i)(B) of this section and/or continuously measure gas composition in accordance with paragraph (m)(5)(ii)(B) or (C) of this section, then those measured data must be used, either directly or after disaggregating to individual sources, to calculate associated gas emissions from flares.

(iv) Use the calculation method of flare stacks in paragraphs (n)(3) through (7) of this section to calculate annual associated gas emissions from flares.

(v) If you monitor the flare with CEMS, use the calculation procedures in paragraph (n)(8) of this section. If the flare receives both associated gas and gas from other sources, then use engineering calculations based on process knowledge and best available data to estimate the portions of the total CO_2 emissions measured by the CEMS that are from associated gas.

(n) *Flare stack emissions.* As applicable for the industry segment, use the procedures in paragraphs (n)(3) through (9) of this section to calculate CO_2, CH_4, and N_2O emissions per flare stack separately from dehydrators as specified in paragraph (e)(5) of this section, completions and workovers with hydraulic fracturing as specified in paragraph (g)(4) of this section, completions and workovers without hydraulic fracturing as specified in paragraph (h)(2) of this section, atmospheric tanks as specified in paragraph (j)(5) of this section, well testing as specified in paragraph (l)(6) of this section, and associated gas as specified in paragraph (m)(5) of this section. Also use the procedures specified in paragraphs (n)(1) through (9) of this section to calculate the collective emissions per flare stack from all miscellaneous flared sources (*i.e.,* sources that are not subject to source-specific flared emissions reporting for your industry segment).

(1) If you have a continuous flow measurement device on gas to the flare, you must use the measured flow volumes to calculate the flare gas emissions from miscellaneous flared sources. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data. If you do not have a continuous flow measurement device on gas to the flare, or if a continuous flow measurement device measures a stream that combines flow from sources that are subject to source-specific flared emissions reporting as well as flow from miscellaneous flared sources, you can use engineering calculations based on process knowledge and best available data to estimate the flow from the miscellaneous flared sources. Best available data also includes the procedures specified in paragraphs (e)(5), (g)(4), (h)(2), (j)(5), (k)(5), (l)(6), and (m)(5) of this section. If a continuous flow measurement device is not installed on an AGR that is routed to a flare, the volumetric CO_2 emissions calculated using AGR Calculation Method 3 or 4 and paragraph (d)(9) of this section must be incorporated into the parameter V_s in Equation W–20 to account for the AGR portion of the total flared CO_2 emissions.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions from miscellaneous flared sources, except when the measured stream to the flare includes emissions from an AGR unit that are comingled with emissions from other sources. If you do not have a continuous gas composition analyzer on gas to the flare, or if the stream to the flare consists of AGR emissions that are comingled with emissions from other sources, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare from an emission source other than an AGR vent as specified in paragraphs (n)(2)(i) through (iii) of this section. For emissions from AGR vents that do not have a continuous gas composition analyzer, you may use either site-specific engineering estimates based on best available data or a default CO_2 mole fraction of 1.

* * * * *

(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W–19 and W–20 of this section. Emissions may be calculated per stream routed to the flare and then summed over all streams per emissions source type. Alternatively, you may sum the total volume of all streams from a particular emission source type, determine the flow-weighted average CO_2 and hydrocarbon concentrations over all streams per source type, and then perform a single calculation using Equation W–19 and a single calculation using Equation W–20 to calculate the total CH_4 and CO_2 emissions per source type.

$$E_{s,CH_4} = V_s * X_{CH_4} * \left[(1-\eta) * Z_L + Z_U\right] \qquad \text{(Eq. W-19)}$$

$$E_{s,CO_2} = V_s * X_{CO_2} + \sum_{j=1}^{5} \left(\eta * V_s * Y_j * R_j * Z_L \right) \qquad \text{(Eq. W-20)}$$

Where:

$E_{s,CH4}$ = Annual CH_4 emissions per emission source type from flare stack in cubic feet, at standard conditions.

$E_{s,CO2}$ = Annual CO_2 emissions per emission source type from flare stack in cubic feet, at standard conditions.

V_s = Volume of gas sent to flare per emission source type in standard cubic feet, during the year as determined in paragraph (e)(5)(i), (g)(4)(i), (h)(2)(i), (j)(5)(i), (l)(6)(i), (m)(5)(i), or (n)(1) of this section.

η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare (default is 0.98).

X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. Use a flow-weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.

X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare per emission source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section. Use a flow-weighted mole fraction if multiple streams from the same source type are combined for the emissions calculation.

Z_U = Fraction of the feed gas sent to an un-lit flare per emission source type determined by engineering estimate and process knowledge based on best available data and operating records.

Z_L = Fraction of the feed gas sent to a burning flare per emission source type (equal to $1 - Z_U$).

Y_j = Mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare per emissions source type as determined in paragraph (e)(5)(ii), (g)(4)(ii), (h)(2)(ii), (j)(5)(ii), (l)(6)(ii), (m)(5)(ii), or (n)(2) of this section.

R_j = Number of carbon atoms in the hydrocarbon constituent j in the feed gas to the flare per emission source type: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

* * * * *

(o) *Centrifugal compressor venting.* If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11). If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are routed to combustion, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply.

(1) * * *

(i) *Centrifugal compressor source as found measurements.* Measure venting from each compressor according to either paragraph (o)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraph (o)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (o)(2)(i) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

* * * * *

(2) *Methods for performing as found measurements from individual centrifugal compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (o)(2)(i) of this section, the volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section, and the volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section.

(i) For blowdown valves on compressors in operating-mode or in standby-pressurized-mode and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (o)(2)(i)(A) through (D) of this section.

* * * * *

(ii) For wet seal oil degassing vents in operating-mode or in standby-pressurized-mode, determine volumetric flow at standard conditions, using one of the methods specified in paragraphs (o)(2)(ii)(A) through (C) of this section. You must quantitatively measure the volumetric flow for wet seal oil degassing vent; you may not use screening methods set forth in § 98.234(a) to screen for emissions for the wet seal oil degassing vent.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(iii) For dry seal vents in operating-mode or in standby-pressurized-mode, determine volumetric flow at standard conditions from each dry seal vent using one of the methods specified in paragraphs (o)(2)(ii)(A) through (D) of this section. If a compressor has more than one dry seal vent, determine the aggregate dry seal vent volumetric flow for the compressor as the sum of the volumetric flows determined for each dry seal vent on the compressor.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(D) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (o)(2)(iii)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the methods. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening dry seal vents.

* * * * *

(4) * * *

(ii) * * *

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these methods, then you must use one of the methods specified in paragraph (o)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

* * * * *

(6) * * *

(i) Using Equation W–21 of this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section that was measured during the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section that was measured for the reporting year.

(ii) Using Equation W–22 of this section, calculate the annual volumetric GHG emissions from each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section that was not measured during the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section that was not measured in the reporting year.

(iii) Using Equation W–23 of this section, develop an emission factor for each compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section. These emission factors must be calculated annually and used in Equation W–22 of this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

* * * * *

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section.

* * * * *

(8) * * *

Tg = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (o)(1)(i)(C), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

* * * * *

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from atmospheric centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–25 of this section. Emissions from centrifugal compressor wet seal oil degassing vents that are routed to a flare, combustion, or vapor recovery are not required to be determined under this paragraph (o).

* * * * *

Count = Total number of centrifugal compressors that have wet seal oil degassing vents that are vented to the atmosphere.

* * * * *

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH4 and CO2 mass emissions as specified in paragraph (p)(11) of this section. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10); and calculate CH4 and CO2 mass emissions as specified in paragraph (p)(11). If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) do not apply and instead you must calculate CH4, CO2, and N2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are routed to combustion, paragraphs (p)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) do not apply.

(1) * * *

(i) *Reciprocating compressor source as found measurements.* Measure venting from each compressor according to either paragraph (p)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraph (p)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (p) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (p)(2)(i) of this section, and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (p)(2)(i) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (p)(2)(i) of this section and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(D) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (p)(6)(ii) of this section.

* * * * *

(2) *Methods for performing as found measurements from individual reciprocating compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (p)(2)(i) of this section. You must determine the volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

* * * * *

(ii) For reciprocating rod packing equipped with an open-ended vent line on compressors in operating-mode or standby-pressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(ii)(A) through (C) of this section.

* * * * *

(C) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (p)(2)(ii)(A) and (B) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph (p)(2)(ii)(C), when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening or measuring rod packing emissions.

(iii) * * *

(A) You must use the methods described in § 98.234(a)(1) through (3) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or for compressors with a closed distance piece, conduct annual detection of gas emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening rod packing emissions.

* * * * *

(4) * * *

(ii) * * *

(C) A high volume sampler according to methods set forth in § 98.234(d).

* * * * *

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (p)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

* * * * *

(6) * * *

(ii) Using Equation W–27 of this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was not measured during the reporting year.

* * * * *

(iii) Using Equation W–28 of this section, develop an emission factor for each compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section. These emission factors must be calculated annually and used in Equation W–27 of this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

* * * * *

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from reciprocating compressor atmospheric venting of rod packing emissions at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–29D of this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery are not required to be determined under this paragraph (p).

* * * * *

Count = Total number of reciprocating compressors with rod packing emissions vented to the atmosphere.

* * * * *

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) and (v) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported.

(1) *Survey requirements.* (i) For the components listed in § 98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive

emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct surveys using any of the leak detection methods listed in § 98.234(a) and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(ii) For the components listed in § 98.232(i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a) except § 98.234(a)(2)(ii) and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iii) For the components listed in § 98.232(c)(21)(i), (e)(7) and (8), (f)(5) through (8), (g)(4), (g)(6) and (7), (h)(5), (h)(7) and (8), and (j)(10)(i) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct surveys using any of the leak detection methods in § 98.234(a)(1)(ii) or (iii) or (a)(2)(ii), as applicable, and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iv) For the components listed in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) or (7), (h)(7) or (8), or (j)(10)(i), that are not subject to fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in § 98.234(a).

(A) If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(c)(21)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in § 98.232(c)(21)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) using the procedures in either paragraph (q)(2) or (3) of this section.

(B) If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(e)(8), (f)(6) and (8), (g)(7), and (h)(8), then you must use the procedures in either paragraph (q)(2) or (3) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in § 98.234(a)(1)(ii) or (iii), or (a)(2)(ii), as applicable, for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) that are not subject to fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites and compressor stations in 40 CFR part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) using the emission calculation requirements in either paragraph (q)(2) or (3) of this section.

(v) For the components listed in § 98.232(d)(7), you must conduct surveys as specified in paragraphs (q)(1)(v)(A) and (B) of this section and you must calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(A) For the components listed in § 98.232(d)(7) that are not subject to the equipment leak standards in the equipment leak standards for processing plants in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may use any of the leak detection methods listed in § 98.234(a).

(B) For the components listed in § 98.232(d)(7) that are subject to the equipment leak standards in the equipment leak standards for processing plants in part 60, subpart OOOOb of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must use either of the leak detection methods in § 98.234(a)(1)(iii) or (a)(2)(ii).

(vi) Except as provided in paragraph (q)(1)(vii) of this section, you must conduct at least one complete leak detection survey in a calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. Except as provided in paragraphs (q)(1)(v)(A) through (G) of this section, a complete leak detection survey is a survey in which all equipment components required to be surveyed as specified in paragraphs (q)(1)(i) through (v) of this section are surveyed.

(A) For components subject to the well site and compressor station fugitive emissions standards in § 60.5397a of this chapter, each survey conducted in accordance with § 60.5397a of this chapter will be considered a complete leak detection survey for purposes of this section.

(B) For components subject to the well site and compressor station fugitive emissions standards in the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter, each survey conducted in accordance with the fugitive emissions standards for well sites and compressor stations in part 60, subpart OOOOb of this chapter will be considered a complete leak detection survey for purposes of this section.

(C) For components subject to the well site and compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for purposes of this section.

(D) For an onshore petroleum and natural gas production facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a single well-pad will be considered a complete leak detection survey for purposes of this section.

(E) For an onshore petroleum and natural gas gathering and boosting facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a gathering compressor station or centralized oil production site, as defined in § 98.238, will be considered a complete leak detection survey for purposes of this section.

(F) For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in the equipment leak standards for onshore natural gas processing plants in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. However, this provision does not absolve you of the responsibility to conduct a complete leak detection survey of all components listed in § 98.232(d)(7) and subject to this paragraph (q) at least once during the calendar year.

(G) For natural gas distribution facilities that choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years as provided in paragraph (q)(1)(vii) of this section, a survey of all required components at the above grade transmission-distribution transfer stations monitored during the calendar year will be considered a complete leak detection survey for purposes of this section.

(vii) Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section. Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years "n," not exceeding a five-year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(2) *Calculation Method 1: Leaker emission factor* calculation methodology. If you elect to use this method, you must use this method for all components included in a complete leak survey. For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (iv) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W–30 of this section and the requirements specified in paragraphs (q)(2)(i) through (ix) of this section. For the industry segment listed in § 98.230(a)(8), the results from Equation W–30 are used to calculate population emission factors on a meter/regulator run basis using Equation W–31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(1)(vii) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

* * * * *

$EF_{s,p}$ = Leaker emission factor for specific component types by leak detection method listed in Tables W–1E, W–2A, W–3A, W–4A, W–5A, W–6A, and W–7A to this subpart.

* * * * *

(i) The leak detection surveys selected for use in Equation W–30 must be conducted during the calendar year as indicated in paragraph (q)(1)(vi) and (vii) of this section, as applicable.

* * * * *

(iii) Onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors consistent with the well type, where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in Table W–1E to this subpart.

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(v) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–2A to this subpart.

* * * * *

(x) Natural gas distribution facilities must use Equation W–30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W–7 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations.

(A) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHGi. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHGi annually according to paragraph (q)(2)(x)(B) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \qquad \text{(Eq. W-31)}$$

Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over "n" years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type "p" during year "y" in standard ("s") cubic feet, as calculated using Equation W–30 of this section.

p = Seven component types listed in Table W–7 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run "w" was operational, in hours during survey year "y" using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year "y".

y = Year of data included in emission factor "$EF_{s,MR,i}$" according to paragraph (q)(2)(x)(B) of this section.

n = Number of years of data, according to paragraph (q)(1)(vii) of this section, whose results are used to calculate emission factor "$EF_{s,MR,i}$" according to paragraph (q)(2)(x)(B) of this section.

(B) The emission factor "$EF_{s,MR,i}$" based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(1)(vii) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 of this section. After the first survey cycle of ''n'' years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year ''y'' and survey results from all previous $(n-1)$ calendar years, such that each annual calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 is based on survey results from ''n'' years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, ''n_{new},'' in the new cycle is smaller than the number of years in the previous cycle, ''n,'' calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous $(n_{new}-1)$ calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section, you must use the meter/regulator run population emission factors calculated using Equation W–31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(3) *Calculation Method 2: Leaker measurement methodology.* If you elect to use this method, you must use this method for all components included in a complete leak survey. For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (v) of this section, you must determine the volumetric flow rate of each natural gas leak identified during the leak survey and aggregate the emissions by component type as specified in paragraphs (q)(3)(i) through (vii) of this section.

(i) Determine the volumetric flow rate of each natural gas leak identified during the leak survey following the methods § 98.234(b) through (d), as appropriate for each leak identified. You do not need to use the same measurement method for each leak measured.

(ii) For each leak, calculate the volume of natural gas emitted as the product of the natural gas flow rate measured in paragraph (q)(3)(i) of this section and the duration of the leak. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey. For each leaking component, account for time the component was not operational (*i.e.,* not operating under pressure) using an engineering estimate based on best available data.

(iii) For each leak, convert the volumetric emissions of natural gas determined in paragraph (q)(3)(ii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(iv) For each leak, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (q)(3)(iii) of this section to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(v) For each leak, convert the GHG volumetric emissions at standard conditions determined in paragraph (q)(3)(iv) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(vi) Sum the CO_2 and CH_4 mass emissions determined in paragraph (q)(3)(v) of this section separately for each type of component required to be surveyed for which a leak was detected.

(vii) For natural gas distribution facilities:

(A) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHG_i using the methods as specified in paragraphs (q)(2)(x)(A) and (B) of this section, except use the GHG mass emissions calculated in paragraph (q)(3)(vi) rather than the emissions calculated using Equation W–30.

(B) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(1)(vii) of this section, you must use the meter/regulator run population emission factors calculated according to paragraph (q)(3)(vii)(A) of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(r) *Equipment leaks by population count.* This paragraph (r) applies to emissions sources listed in § 98.232(c)(21)(ii), (f)(7), (g)(5), (h)(6), and (j)(10)(ii) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in § 98.232(i)(2) through (6) and (j)(11). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph (r) using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B of this section and according to paragraph (r)(6)(ii) of this section.

* * * * *

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a major equipment (*e.g.,* wellhead, separator), component (*e.g.,* connector, open-ended line), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(2)(xi) or (q)(3)(vii)(B) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations.

$Count_e$ = Total number of the emission source type at the facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must count each major equipment piece listed in Table W–1A to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W–4B to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count the: (1) Number of distribution services by material type; (2) miles of distribution mains by material type; (3) number of below grade transmission-distribution transfer stations; and (4) number of below grade metering-regulating stations; as listed in Table W–8 to this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(2)(xi) or (q)(3)(vii)(B) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W–1A, W–4B, W–5B, W–6B, and W–8 to this subpart.

* * * * *

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W–1A of this subpart. Major equipment associated with gas wells are considered gas service equipment in Table W–1A of this subpart. Onshore petroleum and natural gas gathering and boosting facilities shall use the gas service equipment emission factors in Table W–1A of this subpart. Major equipment associated with crude oil wells are considered crude service equipment in Table W–1A of this subpart. Where facilities conduct EOR operations the emission factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

* * * * *

(6) * * *

(i) Below grade transmission-distribution transfer stations, below grade metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in Table W–8 of this subpart to estimate emissions from components listed in § 98.232(i)(2), (4), (5), and (6), respectively.

(ii) Above grade metering-regulating stations that are not above grade transmission-distribution transfer stations must use the meter/regulator run population emission factor calculated in Equation W–31 for the components listed in § 98.232(i)(3). Natural gas distribution facilities that do not have above grade transmission-distribution transfer stations are not required to calculate emissions for above grade metering-regulating stations and are not required to report GHG emissions in § 98.236(r)(2)(v).

(s) *Offshore petroleum and natural gas production facilities.* Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEM in compliance with 30 CFR 550.302 through 304.

(1) Offshore production facilities under BOEM jurisdiction shall report the same annual emissions as calculated and reported by BOEM in data collection and emissions estimation study published by BOEM referenced in 30 CFR 550.302 through 304.

(i) For any calendar year that does not overlap with the most recent BOEM emissions study publication year, report the most recent BOEM reported emissions data published by BOEM referenced in 30 CFR 550.302 through 304. Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEM published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEM jurisdiction must use the most recent monitoring methods and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate and report annual emissions.

(i) For any calendar year that does not overlap with the most recent BOEM emissions study publication, you may report the most recently reported emissions data submitted to demonstrate compliance with this subpart of part 98, with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEM discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEM data collection and emissions estimation methods to estimate emissions. These emission estimates would be used to report emissions from the facility sources as required in paragraph (s)(1)(i) of this section.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEM jurisdiction that were not covered in the previous BOEM data collection cycle must use the most recent BOEM data collection and emissions estimation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate and report emissions.

(t) * * *

(2) * * *

* * * * *

Z_a = Compressibility factor at actual conditions for GHG_i. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

* * * * *

(u) * * *

(2) * * *

(ii) *GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.* For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

* * * * *

(y) *Other large release events.* Calculate CO_2 and CH_4 emissions from other release events for each release that emits GHG in excess of 250 metric tons of CO_2e as specified in paragraphs (y)(1) through (4) of this section.

(1) Estimate the total volume of gas released during the event in standard

cubic feet using any combination of measurement data, engineering estimates, and best available data. Typically, total volume of gas released would be estimated as the product of the estimated flow or release rate and the estimated event duration.

(2) Determine the composition of the gas released to the atmosphere using measurement data, if available, or process knowledge, engineering estimates and best available data. In the event of an explosion or fire, where a portion of the natural gas may be combusted, estimate the composition of the gas released to the atmosphere considering the fraction of natural gas that was converted to CO_2 during the release event.

(3) Calculate the GHG volumetric emissions using Equation W–35 in paragraph (u)(1) of this section.

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.* Except as specified in paragraphs (z)(5) and (6) of this section, calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment using the applicable method in paragraphs (z)(1) through (3) of this section according to the fuel combusted as specified in those paragraphs:

(1) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(1)(i) of this section, then calculate emissions according to paragraph (z)(1)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part or is a blend in which all fuels are listed in Table C–1. If the fuel is natural gas or the blend contains natural gas, the natural gas must also meet the criteria of paragraphs (z)(1)(i)(A) and (B) of this section.

(A) The natural gas must be of pipeline quality specification.

(B) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(ii) For fuels listed in paragraph (z)(1)(i) of this section, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in subpart C of this part, except that natural gas-fired compressor-drivers must use the appropriate emission factor in Table W–9 for quantifying CH_4 emissions instead of the CH_4 emission factor in Table C–2 of subpart C of this part. You must follow all applicable calculation requirements for that tier listed in § 98.33, any monitoring or QA/QC requirements listed for that tier in § 98.34, any missing data procedures specified in § 98.35, and any recordkeeping requirements specified in § 98.37. You must report emissions according to paragraph (z)(4) of this section.

(2) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(2)(i) of this section, then calculate emissions according to paragraph (z)(2)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is natural gas that is not pipeline quality or it is a blend containing natural gas that is not pipeline quality and other gaseous fuels listed in Table C–1. The natural gas also must meet the criteria of paragraphs (z)(2)(i)(A) through (C) of this section.

(A) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(B) The natural gas must have a maximum CO_2 content of 1 percent by volume.

(C) The natural gas must have a minimum CH_4 content of 85 percent by volume.

(ii) For fuels listed in paragraph (z)(2)(i) of this section, calculate CO_2, CH_4, and N_2O emissions according to Tier 2, Tier 3, or Tier 4 listed in subpart C of this part, except that natural gas-fired compressor-drivers must use the appropriate emissions factor in Table W–9 for quantifying CH_4 emissions instead of the CH_4 emission factor in Table C–2 of subpart C of this part. You must follow all applicable calculation requirements for that tier listed in § 98.33, any monitoring or QA/QC requirements listed for that tier in § 98.34, any missing data procedures specified in § 98.35, and any recordkeeping requirements specified in § 98.37. You must report emissions according to paragraph (z)(4) of this section.

(3) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(3)(i) of this section, then calculate emissions according to paragraph (z)(3)(ii) of this section.

(i) The fuel is not listed in Table C–1 of subpart C of this part, the fuel is a blend containing one or more fuels not listed in Table C–1, or the fuel is natural gas or contains natural gas that does not meet the criteria of either paragraph (z)(1)(i) or (z)(2)(i) of this section. This includes natural gas that has a higher heating value of less than 950 Btu per standard cubic feet and natural gas that is not pipeline quality and does not meet the composition criteria of either paragraph (z)(2)(i)(B) or (C) of this section. This also includes field gas that does not meet the definition of natural gas in § 98.238, and blends containing field gas that does not meet the definition of natural gas in § 98.238.

(ii) For fuels listed in paragraph (z)(3)(i) of this section, calculate combustion emissions for each unit or group of units combusting the same fuel as follows:

(A) You may use company records to determine the volume of fuel combusted in the unit or group of units during the reporting year.

(B) If you have a continuous gas composition analyzer on fuel to the combustion unit(s), you must use these compositions for determining the concentration of each hydrocarbon constituent in the flow of gas to the unit or group of units. If you do not have a continuous gas composition analyzer on gas to the combustion unit(s), you may use engineering estimates based on best available data to determine the concentration of each hydrocarbon constituent in the flow of gas to the unit or group of units. Otherwise, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit(s) as specified in the applicable paragraph in (u)(2) of this section.

(C) Calculate GHG volumetric emissions at actual conditions using Equations W–39A and W–39B of this section:

$$E_{a,CO_2} = (V_a * Y_{CO_2}) \quad + \quad \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. W-39A)}$$

$$E_{a,CH_4} = V_a * (1-\eta) * Y_{CH_4} \qquad \text{(Eq. W-39B)}$$

Where:

E_{a,CO_2} = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to the combustion unit or group of units in actual cubic feet, during the year.

Y_{CO_2} = Mole fraction of CO_2 in gas sent to the combustion unit or group of units.

E_{a,CH_4} = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices that are not compressor-drivers, a default of 0.995 can be used. For two-stroke lean-burn compressor-drivers, a default of 0.953 must be used; for four- stroke lean-burn compressor-drivers, a default of 0.962 must be used; and for four-stroke rich-burn compressor-drivers, a default of 0.997 must be used.

Y_j = Mole fraction of hydrocarbon constituent j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to the combustion unit or group of units.

R_j = Number of carbon atoms in the hydrocarbon constituent j in gas sent to the combustion unit or group of units; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus.

Y_{CH_4} = Mole fraction of methane in gas sent to the combustion unit or group of units.

(D) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(E) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(F) Calculate N_2O mass emissions using Equation W–40 of this section.

$$Mass_{N_2O} = \left(1 \times 10^{-3}\right) \times Fuel \times HHV \times EF \qquad \text{(Eq. W-40)}$$

Where:

$Mass_{N_2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Annual mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For field gas or process vent gas, you may use either a default higher heating value of 1.235×10^{-3} mmBtu/scf or a site-specific higher heating value. For natural gas that is not of pipeline quality or that has a higher heating value less than 950 Btu per standard cubic foot, use a site-specific higher heating value.

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

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

(4) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities that are calculated according to the procedures in either paragraph (z)(1)(ii) or (z)(2)(ii) of this section must be reported according to the requirements specified in § 98.236(z) rather than the reporting requirements specified in subpart C of this part.

(5) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each external fuel combustion unit.

(6) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each internal fuel combustion unit.

■ 58. Amend § 98.234 by revising the introductory text, paragraph (a), and paragraph (d)(3) and adding paragraphs (d)(5) and (i) to read as follows:

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 550.

(a) You must use any of the applicable methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) or screening survey(s) as specified in § 98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(i) or (ii) or (q)(1)(v)(A) that occur during a calendar year. You must use one of the methods described in paragraph (a)(1)(ii) or (iii) or (a)(2)(ii) of this section, as applicable, to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(iii) or (q)(1)(v)(B). If electing to comply with § 98.233(q) as specified in § 98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from component types as specified in § 98.233(q)(1)(iv) that occur during a calendar year. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection as specified in either paragraph (a)(1)(i), (ii), or (iii) of this section. You may use any of the methods as specified in paragraphs (a)(1)(i) through (iii) of this section unless you are required to use a specific method to comply with the fugitive emission component requirements in part 60, subpart OOOOa of this chapter or with the fugitive emission component or equipment leak requirements in part 60, OOOOb of this chapter or with the fugitive emission component or equipment leak requirements in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(i) *Optical gas imaging instrument as specified in § 60.18 of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18 of the Alternative work practice for monitoring equipment leaks, § 60.18(i)(1)(i); § 60.18(i)(2)(i) except that the minimum monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR part 60, subpart A, Table 1: Detection Sensitivity Levels; § 60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and § 60.18(i)(2)(iv) and (v); § 60.18(i)(3); § 60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument from an applicable component is a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(ii) *Optical gas imaging instrument as specified in § 60.5397a of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with § 60.5397a(b), (c)(3) and (7), and (e) of this chapter and paragraphs (a)(1)(ii)(A) through (C) of this section.

(A) For the purposes of this subpart, any visible emissions observed by the optical gas imaging instrument from a component required or elected to be monitored as specified in § 98.233(q)(1) is a leak.

(B) For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(C) For the purpose of complying with § 98.233(q)(1)(iv), the phrase ''the collection of fugitive emissions components at well sites and compressor stations'' in § 60.5397a(b) of this chapter means ''the collection of components for which you elect to comply with § 98.233(q)(1)(iv).''

(iii) *Optical gas imaging instrument as specified in appendix K to part 60 of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with appendix K to part 60, *Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging.* Any emissions detected by the optical gas imaging instrument from an applicable component is a leak.

(2) *Method 21.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter as specified in paragraph (a)(2)(i) or (ii) of this section. You may use either of the methods as specified in paragraphs (a)(2)(i) and (ii) of this section unless you are required to use a specific method to comply with the fugitive emission component requirements in part 60, subpart OOOOa of this chapter or with the fugitive emission component or equipment leak requirements in part 60, subpart OOOOb of this chapter or with the fugitive emission component or equipment leak requirements in an applicable approved state plan or applicable Federal plan in part 62 of this chapter. You must survey all applicable source types at the facility needed to conduct a complete equipment leak survey as defined in § 98.233(q)(1). For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(i) *Method 21 with a leak definition of 10,000 ppm.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 10,000 ppm or greater is measured for any applicable component, a leak is detected.

(ii) *Method 21 with a leak definition of 500 ppm.* Use the equipment leak detection methods in Method 21 in appendix A–7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 500 ppm or greater is measured for any applicable component, a leak is detected.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify through-valve leakage. For these acoustic stethoscope type devices, a leak is detected if an audible leak signal is observed or registered by the device. If the acoustic stethoscope type device is used as a screening to a measurement method and a leak is detected, the leak must be measured using any one of the methods specified in paragraphs (b) through (d) of this section.

* * * * *

(d) * * *

(3) For high volume samplers that output methane mass emissions, you must use the calculations in § 98.233(u) and (v) in reverse to determine the natural gas volumetric emissions at standard conditions. For high volume samplers that output methane volumetric flow in actual conditions, divide the volumetric methane flow rate by the mole fraction of methane in the natural gas according to the provisions in § 98.233(u) and estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

* * * * *

(5) If the measured methane flow exceeds the manufacturer's reported quantitation limit or if the measured natural gas flow determined as specified in paragraph (d)(3) of this section exceeds 70 percent of the manufacturer's reported maximum sampling flow rate, then the flow exceeds the capacity of the instrument and you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use calibrated bags according to paragraph (c) of this section to determine the leak or flow rate.

* * * * *

(i) *Special reporting provisions for best available monitoring methods in reporting year 2023*—(1) *Use of best available monitoring methods.* From January 1, 2023, to December 31, 2023, you must use the calculation methodologies and equations in § 98.233 but you may use the best available monitoring method as described in paragraph (i)(2) of this section for any parameter specified in paragraphs (i)(3) through (7) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2023. Starting no later than January 1, 2024, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part.

(2) *Best available monitoring methods.* 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 facility records.

(3) *Best available monitoring methods for measurement data for natural gas pneumatic devices.* You may use best available monitoring methods for any measurement data, including activity data such as gas compositions and hours of operation, that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for natural gas pneumatic devices as specified in § 98.233(a) at onshore natural gas processing plants and for natural gas intermittent bleed pneumatic devices that are monitored as specified in § 98.233(a)(6).

(4) *Best available monitoring methods for measurement data for LNG import/export facilities.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates, gas compositions, and hours of operation, that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in § 98.233(d) at LNG import/export facilities.

(5) *Best available monitoring methods for measurement data for other large release events.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates, gas compositions, and hours of operation, that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for other large release events as specified in § 98.233(y).

(6) *Best available monitoring methods for measurement data for miscellaneous flared sources.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates and gas compositions, that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for miscellaneous flared sources as specified in § 98.233(n)(1) and (2).

(7) *Best available monitoring methods for measurement data for specific emission sources routed to vapor recovery.* You may use best available monitoring methods for any measurement data, including activity data such as flow rates, gas compositions, and hours of operation, that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for dehydrator vents and storage tank vents routed to vapor recovery as specified in § 98.233(e)(4) and (j)(4), respectively.

(8) *Best available monitoring methods for measurement data for compressors.* You may use best available monitoring methods for any measurement data that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for dry seal vents on centrifugal compressors and all compressor sources for centrifugal compressors found in standby-pressurized-mode as specified in § 98.233(o). You may use best available monitoring methods for any measurement data that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for rod packing on reciprocating compressors in standby-pressurized-mode as specified in § 98.233(p).

(9) *Best available monitoring methods for measurement data for a facility that was part of a facility with respect to onshore petroleum and natural gas gathering and boosting prior to January 1, 2023, and meets the definition of onshore natural gas processing in § 98.230(a)(3) effective as of January 1, 2023.* You may use best available monitoring methods for measurement data, including activity data, as listed in paragraphs (i)(9)(i) through (iv) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart.

(i) Temperature and pressure for emergency blowdowns in § 98.233(i).

(ii) Equipment leak surveys in § 98.233(q).

(iii) Centrifugal compressors in § 98.233(o).

(iv) Reciprocating compressors in § 98.233(p).

(10) *Best available monitoring methods for measurement data for a facility that was an onshore natural gas processing facility prior to January 1, 2023, and became part of a facility with respect to onshore petroleum and natural gas gathering and boosting as defined in § 98.238 as of January 1, 2023, due to the change in definition of onshore natural gas processing in § 98.230(a)(3) effective as of January 1, 2023.* You may use best available monitoring methods for measurement data, including activity data, as listed in paragraphs (i)(10)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart.

(i) Natural gas driven pneumatic pumps in § 98.233(c).

(ii) Storage tanks in § 98.233(j).

(iii) Equipment leak surveys in § 98.233(q) and/or equipment leaks by population count in § 98.233(r), as applicable, for equipment components not required for the onshore natural gas processing industry segment (*i.e.,* pumps, flanges, other components, and gathering pipelines).

■ 59. Amend § 98.236 by:

■ a. Revising the introductory text and paragraphs (a)(1) introductory text and (a)(1)(xviii);

■ b. Adding paragraph (a)(1)(xix);

■ c. Revising paragraphs (a)(2) and (a)(3) introductory text;

■ d. Redesignating paragraphs (a)(3)(i) through (vii) as paragraphs (a)(3)(ii) through (viii), respectively;

■ e. Adding new paragraph (a)(3)(i) and paragraph (a)(3)(ix);

■ f. Revising paragraph (a)(4) introductory text;

■ g. Adding paragraph (a)(4)(viii);

■ h. Revising paragraph (a)(5) introductory text;

■ i. Adding paragraph (a)(5)(vii);

■ j. Revising paragraph (a)(6) introductory text;

■ k. Adding paragraph (a)(6)(vi);

■ l. Revising paragraph (a)(7) introductory text;

■ m. Redesignating paragraphs (a)(7)(i) through (vi) as paragraphs (a)(7)(ii) through (vii), respectively;

■ n. Adding new paragraph (a)(7)(i) and paragraph (a)(7)(viii);

■ o. Revising paragraph (a)(8) introductory text;

■ p. Adding paragraph (a)(8)(iv);

■ q. Revising paragraphs (a)(9) introductory text and (a)(9)(xii);

■ r. Adding paragraph (a)(9)(xiii);

■ s. Revising paragraphs (a)(10), (b), (c), (d)(1)(iii), and (d)(2)(iii)(L);

■ t. Adding paragraph (d)(2)(iv);

■ u. Revising paragraphs (e) introductory text, (e)(1) introductory text, and (e)(1)(viii), (xi), (xii), and (xv) through (xviii);

■ v. Adding paragraph (e)(1)(xix);

■ w. Revising paragraph (e)(2);

■ x. Removing and reserving paragraph (e)(3);

■ y. Revising paragraphs (f)(1) introductory text and (f)(1)(iii);

■ z. Adding paragraphs (f)(1)(xi)(F) and (f)(1)(xii)(F);

■ aa. Revising paragraphs (f)(2) introductory text and (f)(2)(iii), (ix) and (x);

■ bb. Adding paragraphs (f)(2)(xi) and (xii);

■ cc. Revising paragraphs (g)(10), (h)(2) introductory text, and (h)(2)(v) through (vii);

■ dd. Adding paragraphs (h)(2)(viii) through (xvi);

■ ee. Revising paragraphs (h)(4) introductory text and (h)(4)(iii) through (v);

■ ff. Adding paragraphs (h)(4)(vi) through (xiv);

■ gg. Revising paragraphs (i)(1) introductory text, (j) introductory text, (j)(1) and (2), (j)(3)(ii), (k)(1)(ii) through (iv), (k)(2) introductory text, (k)(3), (l)(1) introductory text, (l)(2) introductory text, and (l)(2)(vi) through (viii);

■ hh. Adding paragraphs (l)(2)(ix) through (xvii);

■ ii. Revising paragraphs (l)(3) introductory text, (l)(4) introductory text, and (l)(4)(v) through (vii);

■ jj. Adding paragraphs (l)(4)(viii) through (xvi);

■ kk. Revising paragraphs (m)(4) through (8), (n), (o)(1), (o)(2)(i)(B), (o)(2)(ii)(A), (o)(5)(i) through (iii), (p)(1), (p)(2)(ii)(A), (p)(3)(ii) introductory text, (p)(5)(i) through (iii), (q)(1) introductory text, and (q)(1)(iii);

■ ll. Adding paragraphs (q)(1)(vi) and (vii);

■ mm. Revising paragraphs (q)(2), (r)(1) introductory text, and (r)(1)(i);

■ nn. Removing and reserving paragraph (r)(3);

■ oo. Revising paragraphs (s) introductory text, (y), (z) introductory text, (z)(2)(i) and (iv) through (vi), (aa)(3) introductory text, and (aa)(3)(i);

■ pp. Adding paragraph (aa)(3)(viii);

■ qq. Removing and reserving paragraph (aa)(9);

■ rr. Revising paragraph (aa)(10) introductory text;

■ ss. Adding paragraphs (aa)(10)(v) and (vi); and

■ tt. Revising paragraphs (aa)(11)(ii) and (iii), (bb) introductory text, and (cc).

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain reported emissions and related information as specified in this section. Reporters that use a flow or volume measurement system that corrects to standard conditions as provided in the introductory text in § 98.233 for data elements that are otherwise required to be determined at actual conditions, report gas volumes at standard conditions rather than the gas volumes at actual conditions and report the standard temperature and pressure used by the measurement system rather than the actual temperature and pressure.

(a) * * *

(1) *Onshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(1)(i) through (xix) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(xviii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xix) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(2) *Offshore petroleum and natural gas production.* Report the information specified in paragraphs (s) and (y) of this section.

(3) *Onshore natural gas processing.* For the equipment/activities specified in paragraphs (a)(3)(i) through (ix) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

* * * * *

(ix) *Other large release events.* Report the information specified in paragraph (y) of this section.

(4) *Onshore natural gas transmission compression.* For the equipment/activities specified in paragraphs (a)(4)(i) through (viii) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(5) *Underground natural gas storage.* For the equipment/activities specified in paragraphs (a)(5)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(vii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(6) *LNG storage.* For the equipment/activities specified in paragraphs (a)(6)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(vi) *Other large release events.* Report the information specified in paragraph (y) of this section.

(7) *LNG import and export equipment.* For the equipment/activities specified in paragraphs (a)(7)(i) through (viii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

* * * * *

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(8) *Natural gas distribution.* For the equipment/activities specified in paragraphs (a)(8)(i) through (iv) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(iv) *Other large release events.* Report the information specified in paragraph (y) of this section.

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xiii) of this section, report the information specified in the applicable paragraphs of this section.

* * * * *

(xii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xiii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(10) *Onshore natural gas transmission pipeline.* For blowdown vent stacks, report the information specified in paragraphs (i) and (y) of this section.

(b) *Natural gas pneumatic devices.* You must indicate whether the facility contains the following types of equipment: Continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, and intermittent bleed natural gas pneumatic devices. If the facility contains any continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, or intermittent bleed natural gas pneumatic devices, then you must report the information specified in paragraphs (b)(1) through (4) of this section.

(1) The number of natural gas pneumatic devices as specified in paragraphs (b)(1)(i) through (iii) of this section.

(i) For onshore natural gas processing, onshore natural gas transmission compression, and underground natural gas storage facilities, the total number of devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed), determined according to § 98.233(a)(2).

(ii) For onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, the number of devices by each type as specified in paragraphs (b)(1)(ii)(A) through (E) of this section.

(A) Continuous low bleed devices.

(B) Continuous high bleed devices.

(C) Intermittent bleed devices subject to part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter (*i.e.,* the number required to use Equation W–1B).

(D) Intermittent bleed devices not subject to part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter but routinely monitored (*i.e.,* the number electing to use Equation W–1B).

(E) Intermittent bleed devices not subject to part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and not routinely monitored (*i.e.,* the number using Equation W–1A).

(iii) If the reported values in paragraphs (b)(1)(ii)(A), (B), and (E) of this section are estimated values determined according to § 98.233(a)(3), then you must report the information specified in paragraphs (b)(1)(iii)(A) through (C) of this section.

(A) The number of devices of each type reported in paragraphs (b)(1)(ii)(A), (B), and (E) of this section that are counted.

(B) The number of devices of each type reported in paragraphs (b)(1)(ii)(A), (B), and (E) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(2) For each type of pneumatic device for which Equation W–1A of this subpart is used, report the information in paragraphs (b)(2)(i) through (iii) of this section.

(i) The estimated average number of hours in the calendar year that the natural gas pneumatic devices reported in paragraph (b)(1)(i) or paragraphs (b)(1)(ii)(A), (B), and (E) of this section, as applicable, were in service (*i.e.,* supplied with natural gas) in the calendar year (''T_t'' in Equation W–1A of this subpart).

(ii) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices combined, calculated using Equation W–1A of this subpart and § 98.233(a)(5), and reported in paragraph (b)(1)(i) or paragraphs (b)(1)(ii)(A), (B), and (E) of this section, as applicable.

(iii) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined, calculated using Equation W–1A of this subpart and § 98.233(a)(5), and reported in paragraph (b)(1)(i) or paragraphs (b)(1)(ii)(A), (B), and (E) of this section, as applicable.

(3) For intermittent bleed pneumatic devices for which Equation W–1B of this subpart is used, report the information in paragraphs (b)(3)(i) through (iii) of this section.

(i) The total number of intermittent devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''x'' in Equation W–1B of this subpart).

(ii) Average time the intermittent devices were in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning in the calendar year (average value of ''T_z'' in Equation W–1B of this subpart).

(iii) The total number of intermittent devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''Count'' in Equation W–1B of this subpart).

(iv) Average time the intermittent devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year were in service (*i.e.,* supplied with natural gas) during the calendar year (''T_{avg}'' in Equation W–1B of this subpart).

(v) Annual CO_2 emissions, in metric tons CO_2, for the natural gas intermittent bleed pneumatic devices combined for which emissions were calculated using Equation W–1B of this subpart and § 98.233(a)(6).

(vi) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined for which emissions were calculated using Equation W–1B of this subpart and § 98.233(a)(6).

(c) *Natural gas driven pneumatic pumps.* You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (6) of this section. If a pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then include the pump in each of the counts specified in paragraphs (c)(1) through (3) of this section.

(1) Count of natural gas driven pneumatic pumps vented directly to the atmosphere at any point during the year.

(2) Count of natural gas driven pneumatic pumps routed to a flare, combustion, or vapor recovery system at any point during the year.

(3) Total count of natural gas driven pneumatic pumps at the facility.

(4) Average estimated number of hours in the calendar year that natural gas driven pneumatic pumps that vented directly to atmosphere were in service (*i.e.,* supplied with natural gas) (''T'' in Equation W–2 of this subpart).

(5) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(1) and (2).

(6) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(1) and (2).

(d) * * *

(1) * * *

(iii) The calculation method used to calculate CO_2 emissions from the acid gas removal unit, as specified in § 98.233(d). If the AGR vent was routed to a flare and comingled with emissions from other sources and you continuously monitor the flow rate and/or composition, select ''Routed to a flare [§ 98.233(d)(12)(ii)]'' as the calculation method.

* * * * *

(2) * * *

(iii) * * *

(L) Solvent type, from one of the following options: Selexol™, Rectisol®, Purisol™, Fluor Solvent℠, Benfield™, 20 wt% MEA, 30 wt% MEA, 40 wt% MDEA, 50 wt% MDEA, and other.

(iv) If the AGR vent was routed to a flare, then you must report the unique name or ID for the flare stack to which the AGR vent is routed.

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day and glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day. If your facility contains any of the equipment listed in this paragraph (e), then you must report the applicable information in paragraphs (e)(1) through (3) of this section.

(1) For each glycol dehydrator that has an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day (as specified in § 98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xix) of this section for the dehydrator.

* * * * *

(viii) Whether stripping gas is used in dehydrator.

(A) If stripping gas is used in the dehydrator, type of stripping gas used (dry natural gas, flash gas, nitrogen/inert gas, other).

(B) If stripping gas is used in the dehydrator, average flow rate of stripping gas in standard cubic feet per minute.

* * * * *

(xi) Temperature of the wet natural gas at the absorber inlet, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas at the absorber inlet, in pounds per square inch gauge.

* * * * *

(xv) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(xvi) If a flash tank separator is used in the dehydrator, then you must report the information specified in paragraphs (e)(1)(xvi)(A) through (I) of this section for the emissions from the flash tank vent.

(A) Flash tank vent gas flow rate in standard cubic feet per hour.

(B) Flow-weighted average mole fraction of CO_2 in flash tank vent gas (''X_{CO2}'' in Equation W–20 of this subpart if the flash tank vent gas is routed to a flare).

(C) Flow-weighted average mole fraction of CH_4 in flash tank vent gas (''X_{CH4}'' in Equation W–19 of this subpart if the flash tank vent gas is routed to a flare).

(D) Whether any flash gas emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, routed to a vapor recovery system, used as stripping gas, or any combination.

(E) Annual CO_2 emissions, in metric tons CO_2, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv), and, if applicable, (e)(1)(vi)(A).

(F) Annual CH_4 emissions, in metric tons CH_4, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv) and, if applicable, (e)(1)(vi)(A).

(G) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing flash gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(H) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing flash gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(I) Annual N_2O emissions, in metric tons N_2O, that resulted from routing flash gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(xvii) If flash tank emissions were routed to a flare, then you must report the information specified in paragraphs (e)(1)(xvii)(A) through (G) of this section for the flared emissions from the flash tank vent.

(A) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (e)(1)(xvi)(H) and (I) and (e)(1)(xvii)(B) through (G) of this section do not apply.

(B) Indicate whether all gas from the flash tank was measured using a continuous flow monitor.

(C) Indicate whether all gas from the flash tank was measured with a continuous gas composition analyzer.

(D) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(E) Total volume of gas from the flash tank to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(F) Fraction of total flared gas from the flash tank routed to an un-lit flare (''Z_u'' in Equation W–19 of this subpart).

(G) Average flare combustion efficiency, expressed as a fraction of gas from the flash tank combusted by a burning flare.

(xviii) Report the information specified in paragraphs (e)(1)(xviii)(A) through (I) of this section for the emissions from the dehydrator still vent.

(A) Still vent gas flow rate in standard cubic feet per hour.

(B) Flow-weighted average mole fraction of CO_2 in still vent gas (''X_{CO2}'' in Equation W–20 of this subpart if the flash tank vent gas is routed to a flare).

(C) Flow-weighted average mole fraction of CH_4 in still vent gas (''X_{CH4}'' in Equation W–19 of this subpart if the flash tank vent gas is routed to a flare).

(D) Whether any still vent emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, or routed to a vapor recovery system.

(E) Annual CO_2 emissions, in metric tons CO_2, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv), and, if applicable, (e)(1)(vi)(A).

(F) Annual CH_4 emissions, in metric tons CH_4, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(iv) and, if applicable, (e)(1)(vi)(A).

(G) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing still vent gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(H) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing still vent gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(I) Annual N_2O emissions, in metric tons N_2O, that resulted from routing still vent gas to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1)(v) and, if applicable, (e)(1)(vi)(B).

(xix) If emissions from the still vent were routed to a flare, then you must report the information specified in paragraphs (e)(1)(xix)(A) through (G) of this section for the flared emissions from the still vent.

(A) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (e)(1)(xviii)(H) and (I) and (e)(1)(xix)(B) through (G) of this section do not apply.

(B) Indicate whether all gas from the still vent was measured using a continuous flow monitor.

(C) Indicate whether all gas from the still vent was measured with a continuous gas composition analyzer.

(D) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(E) Total volume of gas from the still vent to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(F) Fraction of total flared gas from the still vent routed to an un-lit flare (''Z_u'' in Equation W–19 of this subpart).

(G) Average flare combustion efficiency, expressed as a fraction of gas from the still vent combusted by a burning flare.

(2) You must report the information specified in paragraphs (e)(2)(i) through (v) of this section for all glycol dehydrators with an annual average daily natural gas throughput greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day (as specified in § 98.233(e)(2)) at the facility.

(i) The total number of dehydrators at the facility.

(ii) Whether any dehydrator emissions were routed to a vapor recovery system. If any dehydrator emissions were routed to a vapor recovery system, then you must report the total number of dehydrators at the facility that routed to a vapor recovery system.

(iii) Whether any dehydrator emissions were routed to a control device other than a vapor recovery system or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a control device(s) other than a vapor recovery system or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were routed to each type of control device.

(iv) Whether any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (L) of this section.

(A) The total number of dehydrators routed to a flare or regenerator firebox/fire tubes.

(B) Indicate whether all gas from the dehydrators routed to flares was measured using a continuous flow monitor.

(C) Indicate whether all gas from the dehydrators routed to flares was measured with a continuous gas composition analyzer.

(D) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(E) Total volume of gas from dehydrators to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(F) Fraction of total flared gas from the dehydrators routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(G) Average flare combustion efficiency, expressed as a fraction of gas from the dehydrators combusted by a burning flare.

(H) Flow-weighted average mole fraction of CH_4 in gas from the dehydrators routed to a flare (''X_{CH4}'' in Equation W–19 of this subpart).

(I) Flow-weighted average mole fraction of CO_2 in gas from the dehydrators routed to a flare (''X_{CO2}'' in Equation W–20 of this subpart).

(J) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(5) and, if applicable, (e)(4)(ii).

(K) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(5) and, if applicable, (e)(4)(ii).

(L) Annual N_2O emissions, in metric tons N_2O, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(5) and, if applicable, (e)(4)(ii).

(v) For dehydrator emissions that were not routed to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4)(i), where emissions are added together for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4)(i), where emissions are added together for all such dehydrators.

* * * * *

(f) * * *

(1) For each sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells by unloading type combination.

* * * * *

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloading).

* * * * *

(xi) * * *

(F) Unloading type (automated or manual).

(xii) * * *

(F) Unloading type (automated or manual).

(2) For each sub-basin for which you used Calculation Method 2 or 3 (as specified in § 93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in paragraphs (f)(2)(i) through (xii) of this section. Report information separately for each calculation method and unloading type combination.

* * * * *

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloadings).

* * * * *

(ix) Average flow-line rate of gas (average of ''SFR_p'' from Equation W–8 or W–9 of this subpart, as applicable), at standard conditions in cubic feet per hour.

(x) Cumulative amount of time that wells were left open to the atmosphere during unloading events (sum of ''$HR_{p,q}$'' from Equation W–8 or W–9 of this subpart, as applicable), in hours.

(xi) For wells without plunger lifts, the information in paragraphs (f)(2)(xi)(A) through (C) of this section.

(A) Average internal casing diameter (average of ''CD_p'' from Equation W–8 of this subpart), in inches.

(B) Average well depth (average of ''WD_p'' from Equation W–8 of this subpart), in feet.

(C) Average shut-in pressure, surface pressure, or casing pressure (average of ''SP_p'' from Equation W–8 of this subpart), in pounds per square inch absolute.

(xii) For wells with plunger lifts, the information in paragraphs (f)(2)(xii)(A) through (C) of this section.

(A) Average internal tubing diameter (average of ''TD_p'' from Equation W–9 of this subpart), in inches.

(B) Average tubing depth (average of ''WD_p'' from Equation W–9 of this subpart), in feet.

(C) Average flow line pressure (average of ''SP_p'' from Equation W–9 of this subpart), in pounds per square inch absolute.

(g) * * *

(10) If the well emissions were routed to a flare, then you must report the information specified in paragraphs (g)(10)(i) through (xi) of this section.

(i) Indicate whether the total emissions reported under paragraphs (g)(8) and (9) of this section include vented emissions during the initial flowback period.

(ii) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraph (g)(9) and paragraphs (g)(10)(iii) through (xi) of this section do not apply.

(iii) Indicate whether all of the gas from completions and workovers was measured using continuous flow monitors.

(iv) Indicate whether all of the gas streams from completions and workovers were measured with continuous gas composition analyzers.

(v) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(vi) Total volume of gas from completions and workovers to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(vii) Fraction of total flared gas from completions and workovers routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(viii) Average flare combustion efficiency, expressed as a fraction of gas from completions and workovers combusted by a burning flare.

(ix) Flow-weighted average mole fraction of CH_4 in gas from completions and workovers routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(x) Flow-weighted average mole fraction of CO_2 in gas from completions and workovers routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xi) Total N_2O emissions, in metric tons N_2O.

(h) * * *

(2) For each sub-basin with gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (xvi) of this section.

* * * * *

(v) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (h)(2)(vi) through (xii), (xiv), and (xv) of this section do not apply.

(vi) Indicate whether all of the gas from completions was measured using continuous flow monitors.

(vii) Indicate whether all of the gas streams from completions were measured with continuous gas composition analyzers.

(viii) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(ix) Total volume of gas from completions to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(x) Fraction of total flared gas from completions routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(xi) Average flare combustion efficiency, expressed as a fraction of gas from completions combusted by a burning flare.

(xii) Flow-weighted average mole fraction of CH_4 in gas from completions routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xiii) Flow-weighted average mole fraction of CO_2 in gas from completions routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xiv) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(xv) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(xvi) Annual N_2O emissions, in metric tons N_2O, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

* * * * *

(4) For each sub-basin with gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) through (xiv) of this section.

* * * * *

(iii) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (h)(4)(iv) through (x), (xii), and (xiii) of this section do not apply.

(iv) Indicate whether all of the gas from workovers was measured using continuous flow monitors.

(v) Indicate whether all of the gas streams from workovers were measured with continuous gas composition analyzers.

(vi) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(vii) Total volume of gas from workovers to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(viii) Fraction of total flared gas from workovers routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(ix) Average flare combustion efficiency, expressed as a fraction of gas from workovers combusted by a burning flare.

(x) Flow-weighted average mole fraction of CH_4 in gas from workovers routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xi) Flow-weighted average mole fraction of CO_2 in gas from workovers routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(xiii) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers that flared gas, calculated as specified in § 98.233(h)(2).

(xiv) Annual N_2O emissions, in metric tons N_2O per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(i) * * *

(1) *Report by equipment or event type.* If you calculated emissions from blowdown vent stacks by the seven categories listed in § 98.233(i)(2)(iv) for onshore natural gas processing, onshore natural gas transmission compression, LNG import and export equipment, or onshore petroleum and natural gas gathering and boosting industry segments, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2)(iv) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each ''equipment or event type'' (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the ''equipment or event type'' (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

* * * * *

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* You must indicate whether your facility sends hydrocarbon produced liquids to atmospheric tanks. If your facility sends hydrocarbon produced liquids to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and

boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraph (j)(1)(ix) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual hydrocarbon liquids volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with hydrocarbon liquids production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total volume of hydrocarbon liquids from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

(vi) The average sales oil or stabilized hydrocarbon liquids API gravity, in degrees.

(vii) The flow-weighted average concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CO_2 in the flash gas for each storage tank times the throughput for that storage tank, divided by the sum of all throughputs from storage tanks) (''X_{CO2}'' in Equation W–20 of this subpart if the flash gas is routed to a flare).

(viii) The flow-weighted average concentration (mole fraction) of CH4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks (calculated as the sum of all products of the concentration of CH_4 in the flash gas for each storage tank times the throughput for that storage tank, divided by the sum of all throughputs from storage tanks) (''X_{CH4}'' in Equation W–19 of this subpart and ''Y_1'' in Equation W–20 of this subpart if the flash gas is routed to a flare).

(ix) The number of wells sending hydrocarbon liquids to gas-liquid separators or directly to atmospheric tanks.

(x) Count of atmospheric tanks specified in paragraphs (j)(1)(x)(A) through (D) of this section.

(A) The number of atmospheric tanks.

(B) The number of atmospheric tanks that vented gas directly to the atmosphere and did not control emissions using a vapor recovery system or one or more flares at any point during the reporting year.

(C) The number of atmospheric tanks that routed emissions to vapor recovery and/or one or more flares at any point during the reporting year.

(D) The number of atmospheric tanks in paragraph (j)(1)(x)(C) of this section that had an open or unseated thief hatch at some point during the year while the tank was also routing emissions to a vapor recovery system and/or a flare.

(xi) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(B) of this section, you must report the information specified in paragraphs (j)(1)(xi)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(B) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(xii) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(C) of this section, you must report the information specified in paragraphs (j)(1)(xii)(A) through (N) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1), (2), and (4).

(B) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1), (2), and (4).

(C) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (j)(1)(xii)(D) through (K), (M), and (N) of this section do not apply.

(D) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) was measured using a continuous flow monitor.

(E) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) was measured with a continuous gas composition analyzer.

(F) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(G) Total volume of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) that was routed to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(H) Fraction of total flared gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) that was routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(I) Average flare combustion efficiency, expressed as a fraction of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(1)(xii) combusted by a burning flare.

(J) Annual CO_2 emissions, in metric tons CO_2, from flares used to control emissions, calculated according to § 98.233(j)(5).

(K) Annual CH_4 emissions, in metric tons CH_4, from flares used to control emissions, calculated according to § 98.233(j)(5).

(L) Annual N_2O emissions, in metric tons N_2O, from flares used to control emissions, calculated according to § 98.233(j)(5).

(M) Total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(N) Total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(xiii) For the atmospheric tanks at your facility identified in paragraph (j)(1)(x)(D) of this section, the total volume of gas vented through open or unseated thief hatches, in scf, during periods while the tanks were also routing emissions to vapor recovery systems and/or flares.

(2) If you used Calculation Method 3 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (E) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3 of § 98.233(j).

(A) The total annual hydrocarbon liquids throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with hydrocarbon liquids production less than 10 barrels per day and that send hydrocarbon liquids to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual hydrocarbon liquids throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

(D) The number of atmospheric tanks in the basin.

(E) The total number of separators, wells, or non-separator equipment (''Count'' from Equation W–15 of this subpart) in the basin.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that either did not control emissions with flares or that used flares to control emissions from less than half the annual hydrocarbon liquids received.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (N) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that used flares to control emissions from at least half the annual hydrocarbon liquids received.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (j)(2)(iii)(D) through (K), (M), and (N) of this section do not apply.

(D) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) was measured using a continuous flow monitor.

(E) Indicate whether all of the gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) was measured with a continuous gas composition analyzer.

(F) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(G) Total volume of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) that was routed to a flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(H) Fraction of total flared gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) that was routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(I) Average flare combustion efficiency, expressed as a fraction of gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) combusted by a burning flare.

(J) Flow-weighted average mole fraction of CH_4 in gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) and routed to a flare (''X_{CH4}'' in Equation W–19 of this subpart).

(K) Flow-weighted average mole fraction of CO_2 in gas from the atmospheric tanks in the applicable sub-basin or county and subject to this paragraph (j)(2)(iii) and routed to a flare (''X_{CO2}'' in Equation W–20 of this subpart).

(L) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with flares, calculated according to § 98.233(j)(5) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(M) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with flares, calculated according to § 98.233(j)(5) and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(N) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with flares, calculated according to § 98.233(j)(5).

(3) * * *

(ii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the ''T_{dv}'' values used in Equation W–16 of this subpart).

* * * * *

(k) * * *

(1) * * *

(ii) Indicate if there is a flare attached to the transmission storage tank vent stack.

(iii) Method used to determine if dump valve leakage occurred.

(iv) Indicate whether scrubber dump valve leakage occurred for the transmission storage tank vent according to § 98.233(k)(2) or § 98.233(k)(5).

(2) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iv) of this section, and the vent stack vented directly to the atmosphere during the calendar year, then you must report the information specified in paragraphs (k)(2)(i) through (v) of this section for each transmission storage vent stack where scrubber dump valve leakage occurred.

* * * * *

(3) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iv) of this section, and the vent stack routed to a flare during the calendar year, then you must report the information specified in paragraphs (k)(3)(i) through (iii) of this section.

(i) Indicate whether leak rate was determined using a continuous flow measurement device for the duration of the time that flaring occurred or if an annual measurement was conducted in accordance with paragraph (k)(1)(ii) of this section.

(ii) Measured leakage rate (average leak rate from a continuous flow measurement device) in standard cubic feet per hour.

(iii) Duration of time that flaring occurred in hours, as defined in § 98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(l) * * *

(1) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are not routed to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section.

* * * * *

(2) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are routed to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (xvii) of this section. All reported data elements should be specific to the wells for which Equation W–17A of § 98.233 was used and for which well testing emissions were routed to flares.

* * * * *

(vi) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (l)(2)(vii) through (xiv), (xvi), and (xvii) of this section do not apply.

(vii) Indicate whether all of the gas from well testing routed to flares was measured using continuous flow monitors.

(viii) Indicate whether all of the gas streams from well testing routed to flares were measured with continuous gas composition analyzers.

(ix) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(x) Total volume of gas from well testing routed to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(xi) Fraction of total flared gas from well testing routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(xii) Average flare combustion efficiency, expressed as a fraction of gas from well testing combusted by a burning flare.

(xiii) Flow-weighted average mole fraction of CH_4 in gas from well testing routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xiv) Flow-weighted average mole fraction of CO_2 in gas from well testing routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(xvi) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(xvii) Annual N_2O emissions, in metric tons N2O, calculated according to § 98.233(l).

(3) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not routed to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section.

* * * * *

(4) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were routed to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (xvi) of this section. All reported data elements should be specific to the wells for which Equation W–17B of § 98.233 was used and for which well testing emissions were routed to flares.

* * * * *

(v) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (l)(4)(vi) through (xiii), (xv), and (xvi) of this section do not apply.

(vi) Indicate whether all of the gas from well testing routed to flares was measured using continuous flow monitors.

(vii) Indicate whether all of the gas streams from well testing routed to flares were measured with continuous gas composition analyzers.

(viii) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(ix) Total volume of gas from well testing routed to all flares, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(x) Fraction of total flared gas from well testing routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(xi) Average flare combustion efficiency, expressed as a fraction of gas from well testing combusted by a burning flare.

(xii) Flow-weighted average mole fraction of CH_4 in gas from well testing routed to flares (''X_{CH4}'' in Equation W–19 of this subpart).

(xiii) Flow-weighted average mole fraction of CO_2 in gas from well testing routed to flares (''X_{CO2}'' in Equation W–20 of this subpart).

(xiv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(xv) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(xvi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(l).

(m) * * *

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil (average of the ''GOR'' values used in Equation W–18 of this subpart). Do not report the GOR if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare in the sub-basin (*i.e.,* if you did not use Equation W–18 for any wells with associated gas venting or flaring emissions in the sub-basin).

(5) Volume of oil produced, in barrels, in the calendar year only during the time periods in which associated gas was vented or flared (the sum of ''$V_{p,q}$'' used in Equation W–18 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement. Do not report the volume of oil produced if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare in the sub-basin (*i.e.,* if you did not use Equation W–18 for any wells with associated gas venting or flaring emissions in the sub-basin).

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year only during time periods in which associated gas was vented or flared (the sum of ''SG'' values used in Equation W–18 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement. Do not report the volume of gas sent to sales if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare in the sub-basin (*i.e.,* if you did not use Equation W–18 for any wells with associated gas venting or flaring emissions in the sub-basin).

(7) If you had associated gas emissions vented directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(7)(i) through (viii) of this section for each sub-basin.

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

(ii) Indicate whether all of the associated gas volume vented in the sub-basin was measured using continuous flow monitors.

(iii) Indicate whether all associated gas streams vented in the sub-basin were measured with continuous gas composition analyzers.

(iv) Total volume of associated gas vented in the sub-basin, in standard cubic feet.

(v) Flow-weighted average mole fraction of CH_4 in associated gas vented in the sub-basin.

(vi) Flow-weighted average mole fraction of CO_2 in associated gas vented in the sub-basin.

(vii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(3) and (4).

(viii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(3) and (4).

(8) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(8)(i) through (xiii) of this section for each sub-basin.

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

(ii) Indicate whether the flare was monitored with a CEMS in accordance with § 98.233(n)(8). If a CEMS was used, then paragraphs (m)(8)(iii) through (x), (xii), and (xiii) of this section do not apply.

(iii) Indicate whether all of the associated gas volume routed to flares in the sub-basin was measured using continuous flow monitors.

(iv) Indicate whether all associated gas streams routed to flares in the sub-basin were measured with continuous gas composition analyzers.

(v) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(vi) Total volume of associated gas routed to all flares in the sub-basin, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(vii) Fraction of total flared associated gas in the sub-basin routed to un-lit flares (''Z_u'' in Equation W–19 of this subpart).

(viii) Average flare combustion efficiency, expressed as a fraction of associated gas combusted by a burning flare.

(ix) Flow-weighted average mole fraction of CH_4 in associated gas routed to flares in the sub-basin (''X_{CH4}'' in Equation W–19 of this subpart).

(x) Flow-weighted average mole fraction of CO_2 in associated gas routed to flares in the sub-basin (''X_{CO2}'' in Equation W–20 of this subpart).

(xi) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(5).

(xii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(5).

(xiii) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(m)(5).

(n) *Flare stacks.* You must indicate if your facility has any flare stacks to which emissions are routed from miscellaneous flared sources (*i.e.,* sources other than those subject to § 98.233(e), (g), (h), (j), (l), or (m), as applicable for the industry segment). If you have any miscellaneous flared sources, you must report the information specified in paragraph (n)(1) of this section for each flare used to control emissions from such sources. Additionally, for each flare at your facility, regardless of the source(s) controlled, you must report the information specified in paragraph (n)(2) of this section.

(1) For each flare stack used to control miscellaneous flared sources, you must report the information specified in paragraph (n)(1)(i) through (xiv) of this section.

(i) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

(ii) Indicate whether the flare stack has a continuous flow measurement device.

(iii) Indicate whether the flare stack has a continuous gas composition analyzer on feed gas to the flare.

(iv) Indicate whether only the default HHV, only a site-specific HHV(s), or both the default and site-specific HHVs (depending on the stream to the flare) were used in Equation W–40 to calculate N_2O emissions.

(v) Estimated fraction of total volume flared that was received from another facility solely for flaring (*e.g.,* gas separated from liquid at a production facility that is routed to a flare that is assigned to an onshore petroleum and natural gas gathering and boosting facility).

(vi) Volume of gas from miscellaneous flared sources sent to the flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(vii) Fraction of the feed gas sent to an un-lit flare (''Z_u'' in Equation W–19 of this subpart).

(viii) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare.

(ix) Flow-weighted average mole fraction of CH_4 in the feed gas from miscellaneous flared sources to the flare (''X_{CH4}'' in Equation W–19 of this subpart).

(x) Flow-weighted average mole fraction of CO_2 in the feed gas from miscellaneous flared sources to the flare (''X_{CO2}'' in Equation W–20 of this subpart).

(xi) Annual CO_2 emissions, in metric tons CO_2 (refer to Equation W–20 of this subpart). If gas from an acid gas removal unit is routed to the flare, then the CO_2 emissions to report should exclude the CO_2 emissions reported under paragraph (d)(1)(v) of this section to prevent double counting of emissions.

(xii) Annual CH_4 emissions, in metric tons CH_4 (refer to Equation W–19 of this subpart).

(xiii) Annual N_2O emissions, in metric tons N_2O (refer to Equation W–40 of this subpart).

(xiv) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used to measure emissions from the flare, then the information specified in paragraphs (n)(1)(ii) through (x), (xii), and (xiii) of this section do not apply for that flare; report only the CO_2 emissions as specified in paragraph (n)(1)(xi) of this section.

(2) For each flare stack at your facility, you must report the information specified in paragraphs (n)(2)(i) through (ix) of this section.

(i) Unique name or ID for the flare stack.

(ii) Indicate each emission source type that routed emissions to the flare stack during the reporting year (*i.e.,* dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, well testing venting and flaring, associated gas venting and flaring, miscellaneous flared sources).

(iii) Total volume of gas routed to the flare.

(iv) Indicate the type of flare (*i.e.,* open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare).

(v) Indicate the type of flare assist (*i.e.,* unassisted, air-assisted with single speed fan/blower, air-assisted with dual speed fan/blower, air-assisted with variable speed fan/blower, steam-assisted, or pressure-assisted).

(vi) Indicate whether the flare has a continuous pilot or autoigniter.

(vii) If the flare has a continuous pilot, indicate whether the presence of flame is continuously monitored.

(viii) If the flare has a continuous pilot and the presence of a flame is not continuously monitored, indicate how periods when the pilot is not lit are identified (*i.e.,* assumed pilot is always lit, assumed pilot was unlit for a fixed number of hours or fraction of operating hours, visual observations of flare flame, other (specify)).

(ix) Estimated fraction of the total volume routed to the flare when it was not lit.

(o) * * *

(1) *Compressor activity data.* Report the information specified in paragraphs (o)(1)(i) through (x) of this section, as applicable, for each centrifugal compressor located at your facility.

(i) Unique name or ID for the centrifugal compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) If you conducted volumetric emission measurements as specified in § 98.233(o)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate whether the compressor has blind flanges installed and associated dates.

(vii) Indicate whether the compressor has wet or dry seals.

(viii) If the compressor has wet seals, the number of wet seals.

(ix) If the compressor has dry seals, the number of dry seals.

(x) Power output of the compressor driver (hp).

(2) * * *

(i) * * *

(B) Centrifugal compressor source (wet seal, dry seal, isolation valve, or blowdown valve).

* * * * *

(ii) * * *

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion, or vapor recovery.

* * * * *

(5) * * *

(i) Report the following activity data.

(A) Total number of centrifugal compressors at the facility.

(B) Number of centrifugal compressors that have wet seals.

(C) Number of centrifugal compressors that have atmospheric wet seal oil degassing vents (*i.e.,* wet seal oil degassing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery).

(ii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(iii) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(p) * * *

(1) *Compressor activity data.* Report the information specified in paragraphs (p)(1)(i) through (vii) of this section, as applicable, for each reciprocating compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) If you conducted volumetric emission measurements as specified in § 98.233(p)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate whether the compressor has blind flanges installed and associated dates.

(vii) Power output of the compressor driver (hp).

(2) * * *

(ii) * * *

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion, or vapor recovery.

* * * * *

(3) * * *

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W–28 was used to calculate emissions in Equation W–27, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section.

* * * * *

(5) * * *

(i) Report the following activity data.

(A) Total number of reciprocating compressors at the facility.

(B) Number of reciprocating compressors that have rod packing emissions vented to the atmosphere (*i.e.,* rod packing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery).

(ii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors with rod packing emissions vented to the atmosphere.

(iii) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors with rod packing emissions vented to the atmosphere.

(q) * * *

(1) You must report the information specified in paragraphs (q)(1)(i) through (vii) of this section.

* * * * *

(iii) Except for natural gas distribution facilities, indicate whether any of the leak detection surveys used in calculating emissions per § 98.233(q)(2) were conducted for compliance with any of the standards in paragraphs (q)(1)(iii)(A) through (E) of this section. Report the indication per facility, not per component type, and indicate all that apply for the facility.

(A) The well site or compressor station fugitive emissions standards in § 60.5397a of this chapter.

(B) The well site or compressor station fugitive emissions standards in part 60, subpart OOOOb of this chapter.

(C) The well site or compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(D) The standards for equipment leaks at onshore natural gas plants in part 60, subpart OOOOb of this chapter.

(E) The standards for equipment leaks at onshore natural gas plants in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

* * * * *

(vi) Report whether emissions were calculated using Calculation Method 1 (leaker factor emission calculation methodology) and/or using Calculation Method 2 (leaker measurement methodology).

(vii) For facilities in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, report the number of major equipment (as listed in Table W–1A) by service type for which leak detection surveys were conducted and emissions calculated according to § 98.233(q).

(2) You must indicate whether your facility contains any of the component types subject to or complying with § 98.233(q) that are listed in § 98.232(c)(21), (d)(7), (e)(7) or (8), (f)(5), through (8), (g)(4), (g)(6) or (7), (h)(5), (h)(7) or (8), (i)(1), or (j)(10) for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero (''0'') for the information required according to paragraphs (q)(2)(ii) through (v) of this section. If you used Calculation Method 1 (leaker factor emission calculation methodology) for some complete leak surveys and used Calculation Method 2 (leaker measurement methodology) for some complete leak surveys, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section separately for component surveys using Calculation Method 1 and Calculation Method 2.

(i) Component type.

(ii) Total number of the surveyed component type that were identified as leaking in the calendar year (''x_p'' in Equation W–30 of this subpart for the component type or the number of leaks measured for the specified component type according to the provisions in § 98.233(q)(3)(i)).

(iii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of ''$T_{p,z}$'' from Equation W–30 of this subpart for the component type or average duration of leaks for the specified component type determined according to the provisions in § 98.233(q)(3)(ii)).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using Equation W–30 or § 98.233(q)(3)(vi) (for surveyed components only).

(v) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using Equation W–30 or § 98.233(q)(3)(vi) (for surveyed components only).

* * * * *

(r) * * *

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W–32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by equipment type and service type.

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the equipment type and service type.

* * * * *

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for each emission source type listed in the most recent BOEM study.

* * * * *

(y) *Other large release events.* You must indicate whether there were any other large release events from your facility during the reporting year. If there were any other large release events, you must report the total number of other large release events from your facility that occurred during the reporting year and, for each other large release event, report the information specified in paragraphs (y)(1) through (8) of this section.

(1) Unique release event identification number (*e.g.,* Event 1, Event 2).

(2) The approximate start date, start time, and duration (in hours) of the release event.

(3) A general description of the event. Include:

(i) Identification of the equipment involved in the release.

(ii) A description of how the release occurred, from one of the following categories: fire/explosion, gas well blowout, oil well blowout, gas well release, oil well release, pressure relief, large leak, and other (specify).

(iii) A description of the technology or method used to identify the release.

(iv) An indication of whether the release was identified under the provisions of part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(v) An indication of whether a portion of the natural gas released was combusted during the release, and if so, the fraction of the natural gas released that was estimated to be combusted.

(4) The total volume of gas released during the event in standard cubic feet.

(5) The volume fraction of CO_2 in the gas released during the event.

(6) The volume fraction of CH_4 in the gas released during the event.

(7) Annual CO_2 emissions, in metric tons CO_2, from the release event.

(8) Annual CH_4 emissions, in metric tons CH_4, from the release event.

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by § 98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xix), (a)(8)(i), or (a)(9)(xiii) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xix), (a)(8)(i), or (a)(9)(xiii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

* * * * *

(2) * * *

(i) The type of combustion unit. For internal fuel combustion units of any heat capacity that are compressor-drivers, you must also specify the design class as: 2-stroke lean-burn, 4-

stroke lean-burn, 4-stroke rich-burn, or other.

* * * * *

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(z)(1) through (3).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) through (3).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) through (3).

(aa) * * *

(3) For natural gas processing, if your facility fractionates NGLs and also reports as a supplier to subpart NN of this part, you must report the information specified in paragraphs (aa)(3)(ii) and (aa)(3)(v) through (viii) of this section. Otherwise, report the information specified in paragraphs (aa)(3)(i) through (viii) of this section.

(i) The quantity of natural gas received at the gas processing plant for processing in the calendar year, in thousand standard cubic feet.

* * * * *

(viii) Indicate whether the facility reports as a supplier to subpart NN of this part.

* * * * *

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (vi) of this section.

* * * * *

(v) The number of compressor stations in the facility.

(vi) The number of centralized oil production sites in the facility.

(11) * * *

(ii) The quantity of natural gas withdrawn from underground natural gas storage and LNG storage (regasification) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to underground natural gas storage and LNG storage (liquefied) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

* * * * *

(bb) For any missing data procedures used, report the information in § 98.3(c)(8) and the procedures used to substitute an unavailable value of a parameter, except as provided in paragraphs (bb)(1) and (2) of this section.

* * * * *

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i) or (ii), (g)(5)(iii)(A) or (B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(v), (l)(2)(v), (l)(3)(iv), (l)(4)(iv), or (m)(5) or (6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

■ 60. Amend § 98.238 by:

■ a. Adding a definition for ''Centralized oil production site'' in alphabetical order;

■ b. Revising the definitions for ''Compressor mode'' and ''Compressor source'';

■ c. Adding a definition for ''Compressor station'' in alphabetical order;

■ d. Removing the second definition for ''Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements'';

■ e. Revising the definitions for ''Flare stack emissions'' and ''Forced extraction of natural gas liquids''; and

■ f. Adding definitions for ''Other large release event,'' ''Routed to combustion'', ''Well blowout'', and ''Well release'' in alphabetical order.

The additions and revisions read as follows:

§ 98.238 Definitions.

* * * * *

Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads.

* * * * *

Compressor mode means the operational and pressurized status of a compressor. For both centrifugal compressors and reciprocating compressors, ''mode'' refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor source means the source of certain venting or leaking emissions from a centrifugal or reciprocating compressor. For centrifugal compressors, ''source'' refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, wet seal oil degassing vents, and dry seal vents. For reciprocating compressors, ''source'' refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and rod packing emissions.

Compressor station means any permanent combination of one or more compressors located on one or more contiguous or adjacent properties that are part of the onshore petroleum and natural gas gathering and boosting facility that move natural gas at increased pressure through gathering pipelines or into or out of storage.

* * * * *

Flare stack emissions means CO_2 in gas routed to a flare, CO_2 from partial combustion of hydrocarbons in gas routed to a flare, CH_4 emissions resulting from the incomplete combustion of hydrocarbons in gas routed to a flare, and N_2O resulting from operation of a flare.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include natural gas dehydration, the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid.

* * * * *

Other large release event means an unplanned, unexpected, and uncontrolled release to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies in § 98.233 to appropriately estimate these emissions. Other large release events include, but are not limited to, well blowouts, well releases, pressure relief valve releases from process equipment other than onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, and releases that occur as a result of an accident, equipment rupture, fire, or explosion. Other large release events also include failure of equipment or equipment components such that a single equipment leak or release has emissions that exceed the emissions calculated for that source using applicable methods in § 98.233 by the threshold in § 98.233(y).

* * * * *

Routed to combustion means, for onshore petroleum and natural gas production facilities, natural gas distribution facilities, and onshore petroleum and natural gas gathering and boosting facilities, that emissions are routed to stationary or portable fuel combustion equipment specified in § 98.232(c)(22), (i)(7), or (j)(12), as applicable. For all other industry segments in this subpart, routed to combustion means that emissions are routed to a stationary fuel combustion unit subject to subpart C of this part (General Stationary Fuel Combustion Sources).

* * * * *

Well blowout means a complete loss of well control for a long duration of time resulting in an emissions release.

* * * * *

Well release means a short duration of uncontrolled emissions release from a well followed by a period of controlled emissions release in which control techniques were successfully implemented.

* * * * *

■ 61. Revise table W–1A to subpart W of part 98 to read as follows:

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES

Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Population Emission Factors—Pneumatic Device Vents and Pneumatic Pumps, Gas Service [1]	
Continuous Low Bleed Pneumatic Device Vents [2]	6.8
Continuous High Bleed Pneumatic Device Vents [2]	21.2
Intermittent Bleed Pneumatic Device Vents [2]	8.8
Pneumatic Pumps [3]	13.3
Population Emission Factors—Major Equipment, Gas Service	
Wellhead	0.59
Separator	0.84
Meters/Piping	2.8
Compressor	10
Acid Gas Removal Unit	2.4
Dehydrator	3.1
Heater Treater	0.12
Storage Vessel	0.85
Population Emission Factors—Major Equipment, Crude Service	
Wellhead	0.14
Separator	0.43
Meters/Piping	2.5
Compressor	10
Acid Gas Removal Unit	2.4
Dehydrator	3.1
Heater Treater	0.35
Storage Vessel	0.56
Population Emission Factors—Gathering Pipelines by Material Type [4]	
Protected Steel	0.91
Unprotected Steel	8.0
Plastic/Composite	0.27
Cast Iron	8.2

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] Emission factor is in units of "scf/hour/device."
[3] Emission factor is in units of "scf/hour/pump."
[4] Emission factors are in units of "scf/hour/mile of pipeline."

Table W–1B to Subpart W of Part 98—Default Average Component Counts for Major Onshore Natural Gas Production Equipment and Onshore Petroleum and Natural Gas Gathering and Boosting Equipment for Reporting Year 2022 and Prior Reporting Years

■ 62. Revise the table heading for table W–1B to subpart W of part 98 to read as set forth above.

Table W–1C to Subpart W of Part 98—Default Average Component Counts for Major Crude Oil Production Equipment for Reporting Year 2022 and Prior Reporting Years

■ 63. Revise the table heading for table W–1C to subpart W of part 98 to read as set forth above.

Table W–1D to Subpart W of Part 98—Designation of Eastern and Western U.S. for Reporting Year 2022 and Prior Reporting Years

■ 64. Revise the table heading for table W–1D to subpart W of part 98 to read as set forth above.

■ 65. Revise table W–1E to subpart W of part 98 to read as follows:

TABLE W–1E TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING

Equipment components	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—All Components, Gas Service[1]			
Valve	4.9	3.5	16
Flange	4.1	2.2	11
Connector (other)	1.3	0.8	7.9
Open-Ended Line[2]	2.8	1.9	10
Pressure Relief Valve	4.5	2.8	13
Pump Seal	3.7	1.4	23
Other[3]	4.5	2.8	15
Leaker Emission Factors—All Components, Oil Service			
Valve	3.2	2.2	9.2
Flange	2.7	1.4	11
Connector (other)	1.0	0.6	9.1
Open-Ended Line	1.6	1.1	6.6
Pump[4]	3.7	2.6	15
Other[3]	3.1	2.0	2.9

[1] For multi-phase flow that includes gas, use the gas service emission factors.

[2] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.

[3] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).

[4] The pumps component type in oil service includes agitator seals.

■ 66. Remove table W–2 to subpart W of part 98 and add table W–2A and table W–2B to subpart W of part 98 in numerical order to read as follows:

TABLE W–2A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Onshore natural gas processing plants	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Compressor Components, Gas Service			
Valve[1]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter	19.33	12.39	79
Other[2]	4.1	2.63	17
Leaker Emission Factors—Non-Compressor Components, Gas Service			
Valve[1]	6.42	4.12	26
Connector	5.71	3.66	23
Open-Ended Line	11.27	7.22	46
Pressure Relief Valve	2.01	1.29	8.2
Meter	2.93	1.88	12
Other[2]	4.1	2.63	17

[1] Valves include control valves, block valves and regulator valves.

[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table.

TABLE W–2B TO SUBPART W OF PART 98—DEFAULT WHOLE GAS POPULATION EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Population emission factors—gas service onshore natural gas processing	Emission factor (scf whole gas/hour/device)
Continuous Low Bleed Pneumatic Device Vents	6.8
Continuous High Bleed Pneumatic Device Vents	32.4
Intermittent Bleed Pneumatic Device Vents	2.3

■ 67. Revise table W–3A to subpart W of part 98 to read as follows:

TABLE W–3A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Compressor Components, Gas Service			
Valve[1]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter or Instrument	19.33	12.39	79
Other[2]	4.1	2.63	17
Leaker Emission Factors—Non-Compressor Components, Gas Service			
Valve[1]	6.42	4.12	26
Connector	5.71	3.66	23
Open-Ended Line	11.27	7.22	46
Pressure Relief Valve	2.01	1.29	8.2
Meter or Instrument	2.93	1.88	12
Other[2]	4.1	2.63	17

[1] Valves include control valves, block valves and regulator valves.

[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(e)(8).

■ 68. Revise the table heading and table W–3B to subpart W of part 98 to read as follows:

TABLE W–3B TO SUBPART W OF PART 98—DEFAULT WHOLE GAS POPULATION EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Population emission factors—gas service onshore natural gas transmission compression	Emission factor (scf whole gas/hour/device)
Continuous Low Bleed Pneumatic Device Vents	6.8
Continuous High Bleed Pneumatic Device Vents	32.4
Intermittent Bleed Pneumatic Device Vents	2.3

■ 69. Revise table W–4A to subpart W of part 98 to read as follows:

TABLE W–4A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Storage Station, Gas Service			
Valve [1]	14.84	9.51	61
Connector (other)	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter and Instrument	19.33	12.39	79
Other [2]	4.1	2.63	17
Leaker Emission Factors—Storage Wellheads, Gas Service			
Valve [1]	4.5	3.2	18
Connector (other than flanges)	1.2	0.7	4.9
Flange	3.8	2.0	16
Open-Ended Line	2.5	1.7	10
Pressure Relief Valve	4.1	2.5	17
Other [2]	4.1	2.5	17

[1] Valves include control valves, block valves and regulator valves.

[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(f)(6) and (8).

■ 70. Revise the table heading and table W–4B to subpart W of part 98 to read as follows:

TABLE W–4B TO SUBPART W OF PART 98—DEFAULT POPULATION EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)
Total Hydrocarbon Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.1
Pressure Relief Valve	0.17
Open-Ended Line	0.03
Whole Gas Population Emission Factors—Other Components, Gas Service	
Continuous Low Bleed Pneumatic Device Vents [1]	6.8
Continuous High Bleed Pneumatic Device Vents [1]	32.4
Intermittent Bleed Pneumatic Device Vents [1]	2.3

[1] Emission Factor is in units of "scf whole gas/hour/device."

■ 71. Revise table W–5A to subpart W of part 98 to read as follows:

Table W–5A to Subpart W of Part 98—Default Methane Leaker Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG storage	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—LNG Storage Components, LNG Service			
Valve	1.19	0.23	4.9
Pump Seal	4.00	0.73	16
Connector	0.34	0.11	1.4
Other[1]	1.77	0.99	7.3
Leaker Emission Factors—LNG Storage Components, Gas Service			
Valve[2]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter and Instrument	19.33	12.39	79
Other[3]	4.1	2.63	17

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

[2] Valves include control valves, block valves and regulator valves.

[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(g)(6) and (7).

■ 72. Revise table W–6A to subpart W of part 98 to read as follows:

Table W–6A to Subpart W of Part 98—Default Methane Leaker Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission factor (scf/hour/component)		
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—LNG Terminals Components, LNG Service			
Valve	1.19	0.23	4.9
Pump Seal	4.00	0.73	16.
Connector	0.34	0.11	1.4
Other[1]	1.77	0.99	7.3
Leaker Emission Factors—LNG Terminals Components, Gas Service			
Valve[2]	14.84	9.51	61
Connector	5.59	3.58	23
Open-Ended Line	17.27	11.07	71
Pressure Relief Valve	39.66	25.42	163
Meter and Instrument	19.33	12.39	79
Other[3]	4.1	2.63	17

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

[2] Valves include control valves, block valves and regulator valves.

[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(h)(7) and (8).

■ 73. Revise table W–7 to subpart W of part 98 to read as follows:

TABLE W–7 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Natural gas distribution	Emission factor (scf/hour/component)	
	If you survey using method 21 as specified in § 98.234(a)(2)(i)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—Transmission-Distribution Transfer Station1 Components, Gas Service		
Connector	1.69	6.7
Block Valve	0.557	2.3
Control Valve	9.34	38
Pressure Relief Valve	0.27	1.1
Orifice Meter	0.212	0.87
Regulator	0.772	3.2
Open-ended Line	26.131	107

[1] Excluding customer meters.

■ 74. Add table W–8 to subpart W of part 98 to read as follows:

TABLE W–8 TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION

Natural gas distribution	Emission factor (scf/hour/component)
Population Emission Factors—Below Grade Transmission-Distribution Transfer Station Components and Below Grade Metering-Regulating Station1 Components, Gas Service[2]	
Below Grade T–D Transfer Station	0.30
Below Grade M&R Station	0.30
Population Emission Factors—Distribution Mains, Gas Service[3]	
Unprotected Steel	1.2
Protected Steel	2.3
Plastic	0.45
Cast Iron	2.8
Population Emission Factors—Distribution Services, Gas Service[4]	
Unprotected Steel	0.086
Protected Steel	0.0077
Plastic	0.0016
Copper	0.03

[1] Excluding customer meters.
[2] Emission Factor is in units of "scf/hour/station."
[3] Emission Factor is in units of "scf/hour/mile."
[4] Emission Factor is in units of "scf/hour/number of services."

■ 75. Add table W–9 to subpart W of part 98 in numerical order to read as follows:

TABLE W–9 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS-FIRED COMPRESSOR-DRIVERS

Compressor-driver engine design class	Emission factor (kg CH_4/mmBtu)
2-stroke lean-burn	0.658
4-stroke lean-burn	0.522
4-stroke rich-burn	0.045

Subpart X—Petrochemical Production

■ 76. 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).

■ 77. Amend § 98.244 by revising paragraph (b)(4)(iii) to read as follows:

§ 98.244 vMonitoring and QA/QC requirements.

* * * * *

(b) * * *

(4) * * *

(iii) ASTM D2505–88 (Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography (incorporated by reference, *see* § 98.7).

* * * * *

■ 78. Amend § 98.246 by revising paragraphs (a) introductory text, (a)(2) and (5), (a)(13) and (15), (b)(7) and (8), (c) introductory text, and (c)(3) and (4) and adding paragraph (c)(6) 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 EDC produced that is used in 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 of § 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, 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) of subpart Y of this part 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 (c)(6) of this section.

* * * * *

(3) Information listed in § 98.256(e) of subpart Y of this part 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).

* * * * *

(6) Name and annual quantity (in metric tons) of each product produced in each process unit.

Subpart Y—Petroleum Refineries

■ 79. Amend § 98.253 by:

■ a. Revising paragraph (b) introductory text, paragraph (c) introductory text, and paragraph (e) introductory text;

■ b. Revising Equation Y–18b in paragraph (i)(2);

■ c. Revising parameters ‘‘Mwater’’ and ‘‘Hwater’’ of Equation Y–18b in paragraph (i)(2);

■ d. Adding parameter ‘‘fcoke’’ to Equation Y–18b in paragraph (i)(2); and

■ e. Revising parameter ‘‘Msteam’’ of Equation Y–18f in paragraph (i)(5).

The revisions and addition 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: (1) gas used for the flare pilots, and (2) 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 (c)(5) of this section.

* * * * *

(e) For catalytic reforming units, calculate the CO_2 emissions from coke burn-off using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH_4 and N_2O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

* * * * *

(i) * * *

(2) * * *

$$M_{water} = \rho_{water} \times \left((H_{water}) \times \frac{\pi \times D^2}{4} - \frac{f_{coke} \times M_{coke}}{\rho_{particle}} \right) \quad \text{(Eq. Y-18b)}$$

* * * * *

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).

* * * * *

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.

* * * * *

(5) * * *

* * * * *

M_{steam} = Mass of steam generated and released per decoking cycle (metric tons/cycle) as determined in paragraph (i)(4) of this section.

* * * * *

■ 80. Amend § 98.254 by revising paragraph (d) introductory text and paragraph (e) introductory text to 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).

* * * * *

■ 81. Amend § 98.256 by revising paragraph (k)(6) to read as follows:

§ 98.256 Data reporting requirements.

* * * * *

(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 of this subpart). 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.

* * * * *

■ 82. Amend § 98.257 by:

■ a. Revising paragraphs (b)(45), (46), and (53); and

■ b. Removing and reserving paragraphs (b)(54), (55), and (56).

The revisions read as follows:

§ 98.257 Records that must be retained.

* * * * *

(b) * * *

(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 in § 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 in § 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 in § 98.253) for each delayed coking unit.

* * * * *

Subpart BB—Silicon Carbide Production

■ 83. 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.

■ 84. 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).

Subpart DD—Electrical Transmission and Distribution Equipment Use

■ 85. Amend § 98.300 by revising paragraphs (a) introductory text and (a)(3) and (7) to read as follows:

§ 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:

* * * * *

(3) Switchgear, including closed-pressure and hermetically sealed-pressure switchgear and gas-insulated lines containing fluorinated GHGs, including but not limited to SF6 and PFCs.

* * * * *

(7) Other containers of fluorinated GHG, including but not limited to SF6 and PFCs.

* * * * *

■ 86. Revise § 98.301 to read as follows:

§ 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 CO2e per year emission threshold in Table A–3, you must calculate emissions of each fluorinated GHG, including but not limited to SF_6 and PFCs, 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 of this subpart.

$$E = \sum_j \sum_i NC_{EPS,j} * GHG_{i,w} * GWP_i * EF * 0.000453592 \qquad \text{(Eq. DD-1)}$$

Where:

E = Annual emissions for threshold applicability purposes (metric tons CO2e).

$NC_{EPS,j}$ = the total nameplate capacity of insulating gas j-containing equipment (excluding hermetically sealed-pressure equipment) located within the facility plus the total nameplate capacity of insulting gas j-containing equipment (excluding hermetically sealed-pressure equipment) that is not located within the facility but is under common ownership or control

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in 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 in subpart A of this part is not required to report emissions under subpart DD of this part unless the total estimated emissions from fluorinated gas, including but not limited to SF6 and PFCs, containing equipment located at the facility, as calculated in Equation DD–2 for comparison to the 25,000 metric ton CO2e per year emission threshold in Table A–3 meets or exceeds 25,000 tons CO2e.

$$E = \sum_j \sum_i NC_{other,j} * GHG_{i,w} * GWP_i * EF * 0.000453592 \qquad \text{(Eq. DD-2)}$$

Where:

E = Annual emissions for threshold applicability purposes (metric tons CO2e).

$NC_{other,j}$ = For a facility other than an electric power system, the total nameplate capacity of insulating gas j containing equipment (excluding hermetically sealed-pressure equipment) located within the facility

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in 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.

■ 87. Revise § 98.302 to read as follows:

§ 98.302 GHGs to report.

You must report emissions of each fluorinated GHG, including but not limited to SF_6 and PFC, 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). For acquisitions of equipment containing or insulated with fluorinated GHG, you must report emissions from the equipment after the title to the equipment is transferred to the electric power transmission or distribution entity.

■ 88. Revise § 98.303 to read as follows:

§ 98.303 Calculating GHG emissions.

(a) *Mass-balance approach.* Calculate the annual emissions of each fluorinated GHG (including but not limited to SF_6 and PFC) using the mass-balance approach in Equation DD–3 of this section:

$$\text{User Emissions}_i = GHG_{i,w} * [(\text{Decrease in Insulating gas j Inventory}) + (\text{Acquisitions of Insulating gas j}) - (\text{Disbursements of Insulating gas j}) - (\text{Net Increase in Total Nameplate Capacity of Equipment Operated Containing Insulating gas j})] \qquad \text{(Eq. DD-3)}$$

Where:

User Emissions_i = Emissions of fluorinated GHG i from the facility (pounds).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in 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 Insulating gas j Inventory = (pounds of insulating gas j stored in containers, but not in energized equipment, at the beginning of the year) − (pounds of insulating gas j stored in containers, but not in energized equipment, at the end of the year).

Acquisitions of Insulating gas j = (pounds of each insulating gas j purchased from chemical producers or distributors in bulk) + (pounds of each insulating gas j purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear) + (pounds of each insulating gas j returned to facility after off-site recycling).

Disbursements of Insulating gas j = (pounds of each insulating gas j in bulk and contained in equipment that is sold to other entities) + (pounds of each insulating gas j returned to suppliers) + (pounds of each insulating gas j sent off site for recycling) + (pounds of each insulating gas j sent off-site for destruction).

Net Increase in Total Nameplate Capacity of Equipment Operated containing insulating gas j = (The Nameplate Capacity of new equipment containing insulating gas j in pounds, including hermetically sealed-pressure switchgear) − (Nameplate Capacity of retiring equipment containing insulating gas j in pounds, including hermetically sealed-pressure switchgear). (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 (b)(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 (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 and measure and calculate the total amount of covered 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 covered 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 covered 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. 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) Record the initial system pressure and vessel temperature prior to removing any insulating gas.

(ii) Convert the initial system pressure to a temperature-compensated initial system pressure by using the temperature/pressure curve for that 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 less than 90 percent of the temperature-compensated design operating pressure specified by the manufacturer (in absolute terms), use Equation DD–4 to calculate the nameplate capacity based on the mass recorded under paragraph (b)(5)(vi) of this section.

(iv) Follow one of the following processes, depending on the methodology being used to measure the amount of gas recovered:

(A) Connect a mass flow meter between the electrical equipment and a gas cart; or

(B) 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 the blank-off pressure unless the integrity of the electrical equipment has been compromised in such a way that air will be drawn into the electrical equipment and gas cart if the electrical equipment is drawn into a vacuum. If the integrity of the electrical equipment has been so compromised, recover the insulating gas until the pressure in the electrical equipment is no higher than zero pounds per square inch gauge (0 psig).

(vi) Record the amount of insulating gas recovered (pounds), either based on the reading from the mass flow meter, or 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–4.

(vii) If you are calculating the nameplate capacity pursuant to paragraph (b)(5)(iii)(B), use Equation DD–4 to do so.

$$NC_C = \frac{P_{NC}}{(P_i - P_f)} \times M_R \qquad \text{DD-4}$$

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.

■ 89. Amend § 98.304 by removing and reserving paragraph (a) and revising paragraphs (b)(1), (2), and (4).

The revisions read as follows:

§ 98.304 Monitoring and QA/QC requirements.

* * * * *

(b) * * *

(1) Review inputs to Equation DD–3 of this section 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.

* * * * *

(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.

* * * * *

■ 90. Revise § 98.305 to read as follows:

§ 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.

■ 91. Amend § 98.306 by revising paragraphs (a) introductory text, (d) through (l), and (n) introductory text and adding paragraphs (o) through (r) to read as follows:

§ 98.306 Data reporting requirements.

* * * * *

(a) Nameplate capacity of equipment (pounds) containing each insulating gas:

* * * * *

(d) Pounds of each insulating gas stored in containers, but not in energized equipment, at the beginning of the year.

(e) Pounds of each insulating gas stored in containers, but not in energized equipment, at the end of the year.

(f) Pounds of each insulating gas purchased in bulk from chemical producers or distributors.

(g) Pounds of each insulating gas purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear.

(h) Pounds of each insulating gas returned to facility after off-site recycling.

(i) Pounds of each insulating gas in bulk and contained in equipment sold to other entities.

(j) Pounds of each insulating gas returned to suppliers.

(k) Pounds of each insulating gas sent off-site for recycling.

(l) Pounds of each insulating gas sent off-site for destruction.

* * * * *

(n) The number of insulating gas containing pieces of equipment in each of the following equipment categories:

* * * * *

(o) 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.

(p) 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.

(q) For each unique insulating gas reported in paragraphs (a), (d) through (l), and (n) of this section, an ID number or other appropriate descriptor.

(r) For each ID number or descriptor reported in paragraph (q) 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.

■ 92. Revise § 98.307 to read as follows:

§ 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.

■ 93. Amend § 98.308 by revising the definition of ''Facility'' and adding in alphabetical order definitions for ''Energized'', ''Insulating gas'', ''New equipment'', and ''Retired equipment'' to read as follows:

§ 98.308 Definitions.

* * * * *

Facility, with respect to an electric power system, means the electric power system as defined in this paragraph. 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.

* * * * *

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 SF6 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 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. This includes equipment 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).

* * * * *

Retired equipment, for the purposes of this subpart, means 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. This includes equipment 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

■ 94. 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) * * *

MCFi = Moisture correction factor for the measurement period, volumetric basis.

= 1 when Vi and Ci are measured on a dry basis or if both are measured on a wet basis.

= 1-(fH2O)i when Vi is measured on a wet basis and Ci is measured on a dry basis.

= 1/[1-(fH2O)i] when Vi is measured on a dry basis and Ci is measured on a wet basis.

* * * * *

■ 95. 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

■ 96. 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 of this section. For electrothermic furnaces, carbon containing input materials include carbon electrodes and carbonaceous reducing agents. For Waelz kilns, carbon containing input materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R–1 of § 98.183.

* * * * *

■ 97. Amend § 98.336 by adding paragraph (a)(6) and revising paragraph (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

■ 98. Amend § 98.343 by revising paragraph (a)(2) 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 of 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 of this subpart. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. You may use the 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.

* * * * *

■ 99. Amend § 98.346 by adding paragraphs (i)(6)(i) and (ii) to read as follows:

§ 98.346 Data reporting requirements.

* * * * *

(i) * * *

(6) * * *

(i) The percentage of total recovered CH_4 that is sent to each measurement location (decimal, must total to 1 across all measurement locations at the facility).

(ii) For each measurement location, the percentage of total recovered CH_4 that is sent to a flare, a landfill gas to energy project, or an unknown option if gas is sent off-site for destruction and the type of destruction technology is unknown (decimal, must total to 1 for each measurement location).

* * * * *

■ 100. Revise table HH–1 to subpart HH of part 98 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)	0.17	Weight fraction, wet basis.
k (precipitation plus recirculated leachate[a] <20 inches/year)	0.055	yr^{-1}
k (precipitation plus recirculated leachate[a] 20–40 inches/year)	0.111	yr^{-1}
k (precipitation plus recirculated leachate[a] >40 inches/year)	0.142	yr^{-1}
DOC and k values—Modified bulk MSW option		
DOC (bulk MSW, excluding inerts and C&D waste)	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)	0.02 to 0.057[b]	yr^{-1}
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}

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS—Continued

Factor	Default value	Units
DOC and k values—Waste composition option		
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)	0.055 to 0.142	yr^{-1}
Other parameters—All MSW landfills		
MCF	1..	
DOC_F	0.5.	
F	0.5.	
OX	See Table HH–4 of 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 0.142 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.

Subpart OO—Suppliers of Industrial Greenhouse Gases

■ 101. Amend § 98.416 by revising paragraphs (c)(6) and (7) and (d)(4) and adding paragraph (k) to read as follows:

§ 98.416 Data reporting requirements.

* * * * *

(c) * * *

(6) Harmonized tariff system (HTS) code of the fluorinated GHGs, fluorinated HTFs, or nitrous oxide shipped.

(7) Customs entry summary number and importer number for each shipment.

* * * * *

(d) * * *

(4) Harmonized tariff system (HTS) code of the fluorinated GHGs, fluorinated HTFs, or nitrous oxide shipped.

* * * * *

(k) For nitrous oxide, saturated perfluorocarbons, and sulfur hexafluoride, report the end use(s) for which each GHG is transferred and the aggregated annual quantity of that GHG in metric tons that is transferred to that end use application, if known.

Subpart PP— Suppliers of Carbon Dioxide

■ 102. 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.

* * * * *

■ 103. 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.

■ 104. 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 in paragraph (a)(3).

* * * * *

(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.

* * * * *

■ 105. Amend § 98.426 by adding paragraph (i) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(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) 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.

(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.

■ 106. 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 SS—Electrical Equipment Manufacture or Refurbishment

■ 107. Revise § 98.450 to read as follows:

§ 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 (SF6) and perfluorocarbons (PFCs). The processes include equipment testing, installation, manufacturing, decommissioning and disposal, refurbishing, and storage in gas cylinders and other containers.

■ 108. Revise § 98.451 to read as follows:

§ 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 CO2e 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, including but not limited to SF6 and PFCs, and then sum the emissions of each fluorinated GHG resulting from manufacturing and refurbishing electrical equipment using Equation SS–1 of this subpart.

$$E = \sum_j \sum_i P_j * \text{GHG}_{i,w} * GWP_i * EF * 0.000453592 \qquad \text{(Eq. SS-1)}$$

Where:

E = Annual production process emissions for threshold applicability purposes (metric tons CO2e).

P_j = Total annual purchases of insulating gas j (lbs).

$\text{GHG}_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j if 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.

■ 109. Amend § 98.452 by revising paragraph (a) to read as follows:

§ 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. 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.

* * * * *

■ 110. Amend § 98.453 by:

■ a. Revising paragraph (a);

■ b. Removing and reserving paragraph (b); and

■ c. Revising paragraphs (c) through (g), (h) introductory text, and (i).

The revisions read as follows:

§ 98.453 Calculating GHG emissions.

(a) For each electrical equipment manufacturer or refurbisher, estimate the annual emissions of each fluorinated GHG using the mass-balance approach in Equation SS–2 of this section:

$$\text{User emissions}_i = GHG_{i,w} * [(\text{Decrease in insulating gas j Inventory}) + (\text{Acquisitions of insulating gas j}) - (\text{Disbursements of insulating gas j})] \quad \text{(Eq. SS-2)}$$

Where:

User emissions_i = Annual emissions of each fluorinated GHG i (pounds).

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in 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 insulating gas j Inventory = (Pounds of insulating gas j stored in containers at the beginning of the year) − (Pounds of insulating gas j stored in containers at the end of the year).

Acquisitions of insulating gas j = (Pounds of each insulating gas j purchased from chemical producers or suppliers in bulk) + (Pounds of each insulating gas j returned by equipment users) + (Pounds of each insulating gas j returned to site after off-site recycling).

Disbursements of insulating gas j = (Pounds of each insulating gas j contained in new equipment delivered to customers) + (Pounds of each insulating gas j delivered to equipment users in containers) + (Pounds of each insulating gas j returned to suppliers) + (Pounds of each insulating gas j sent off site for recycling) + (Pounds of each insulating gas j sent off-site for destruction).

* * * * *

(c) Estimate the disbursements of each insulating gas j (including, but not limited to SF_6 and PFCs) 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–3 of this section:

$$D_{GHG} = \sum_{p=1}^{n} Q_p \qquad \text{(Eq.SS-3)}$$

Where:

D_{GHG} = The annual disbursement of each 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 each 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 (including, but not limited to SF_6 and PFCs) 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–4 of this section:

$$Q_p = M_B - M_E - E_L \qquad \text{(Eq.SS-4)}$$

Where:

Q_p = The mass of each 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 each 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 each insulating gas j (including, but not limited to SF_6 and PFCs) disbursed to customers in new equipment or cylinders over the period p is determined using a flowmeter, estimate this quantity using Equation SS–5 of this section:

$$Q_p = M_{mr} - E_L \qquad \text{(Eq. SS-5)}$$

Where:

Q_p = The mass of each insulating gas j (including, but not limited to SF_6 and PFCs) 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 each insulating gas j that has flowed through the flowmeter during the period p.

E_L = The mass of each 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 each 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–6 of this section:

$$E_L = \sum_{j=0}^{n} F_{Ci} * EF_{Ci}$$

(Eq. SS-6)

Where:

E_L = The mass of each fluorinated GHG (including, but not limited to SF_6 and PFCs) or fluorinated GHG mixture 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_{Ci} = 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 each 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 (h)(2) of this section.

* * * * *

(i) Estimate the annual emissions of each 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–7 of this section:

$$EI = GHG_{i,w} * (M_F + M_C - N_I)$$

Eq. SS-7

Where:

EI = Total annual emissions of each insulating gas j from equipment installation at electric transmission or distribution facilities.

$GHG_{i,w}$ = The weight fraction of fluorinated GHG i in insulating gas j if 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 each 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 each 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.

■ 111. Amend § 98.454 by removing and reserving paragraph (a) and revising paragraphs (b), (d) through (f), and (h)(1) through (4).

The revisions read as follows:

§ 98.454 Monitoring and QA/QC requirements.

* * * * *

(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 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.

* * * * *

(d) For purposes of Equations SS–6 of this subpart, the emission factor for the valve-hose combination (EF_C) 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 EF_c (or use an industry-developed value) for each combination of hose and valve fitting, to use in Equation SS–6 of this subpart. The value for EF_C 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 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 insulating gas emitted downstream of the container or flowmeter during the period p.

(f) If the mass of each 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. 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 SF_6, 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.

* * * * *

(h) * * *

(1) Review inputs to Equation SS–2 of this subpart 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 insulating gas may be calculated as negative.

(3) Ensure that for each insulating gas, the beginning-of-year inventory matches the end-of-year inventory from the previous year.

(4) Ensure that for each insulating gas, in addition to the insulating gas purchased from bulk gas distributors, the insulating gas returned from equipment users with or inside equipment and the insulating gas returned from off-site recycling are also accounted for among the total additions.

■ 112. Amend § 98.456 by revising paragraphs (a) through (k) and (n) through (s) and adding paragraphs (u) and (v) to read as follows:

§ 98.456 Data reporting requirements.

* * * * *

(a) Pounds of each insulating gas stored in containers at the beginning of the year.

(b) Pounds of each insulating gas stored in containers at the end of the year.

(c) Pounds of each insulating gas purchased in bulk.

(d) Pounds of each insulating gas returned by equipment users with or inside equipment.

(e) Pounds of each 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 insulating gas returned to suppliers.

(i) Pounds of each insulating gas sent off site for destruction.

(j) Pounds of each insulating gas sent off site to be recycled.

(k) The nameplate capacity of the equipment, in pounds, delivered to customers with insulating gas inside, if different from the quantity in paragraph (f) of this section.

* * * * *

(n) The total number of fill operations for each hose and valve combination, or, F_{Ci} of Equation SS–6 of this subpart.

(o) If the mass of each 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 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 M_F, of Equation SS–7 of this subpart.

(r) Pounds of each insulating gas used to charge the equipment prior to leaving the electrical equipment manufacturer or refurbishment facility, or M_C, of Equation SS–7 of this subpart.

(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–7 of this subpart.

* * * * *

(u) For each unique insulating gas reported in paragraphs (a) through (j) and (o) through (r) of this section, an ID number or other appropriate descriptor.

(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.

■ 113. Revise § 98.458 to read as follows:

§ 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.

Subpart UU—Injection of Carbon Dioxide

■ 114. Amend § 98.470 by redesignating paragraph (c) as paragraph (d) and adding new paragraph (c) to read as follows:

§ 98.470 Definition of the source category.

* * * * *

(c) If you report under subpart VV of this part for a well or group of wells, you are not required to report under this subpart for that well or group of wells.

* * * * *

■ 115. Add subpart VV to read as follows:

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

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

§ 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 International Standards Organization (ISO) standard designated as CSA/ANSI ISO 27916:2019 (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 UU of this part.

(3) 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 (a)(2).

§ 98.481 Reporting threshold.

(a) You must report under this subpart if your CO_2-EOR project uses CSA/ANSI ISO 27916:2019 (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 27916:2019.

(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.

§ 98.482 GHGs to report.

You must report the following from Clause 8 of CSA/ANSI ISO 27916:2019 (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 27916:2019 (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 VV–1 of this section).

$$m_{\text{stored}} = m_{\text{input}} - m_{\text{loss operations}} - m_{\text{loss EOR complex}} \qquad \text{(Equation VV-1)}$$

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 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 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), 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 (c)(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 VV–2 of this section.

$$m_{\text{loss operations}} = m_{\text{loss leakage facilities}} + m_{\text{loss vent/flare}} + m_{\text{loss entrained}} + m_{\text{loss transfer}} \qquad \text{(Equation VV-2)}$$

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 27916:2019 (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 27916:2019 (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 ($m_{\text{loss operations}}$), 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) ($m_{\text{loss leakage facilities}}$).

(2) Loss of CO_2 from venting/flaring from production operations ($m_{\text{loss vent/flare}}$).

(3) Loss of CO_2 due to entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected ($m_{\text{loss entrained}}$).

(4) Loss of CO_2 due to any transfer of CO_2 outside the CO_2-EOR project ($m_{\text{loss transfer}}$).

(f) The total mass of CO_2 loss from the EOR complex ($m_{\text{loss EOR complex}}$).

(g) Annual documentation that contains the following components as described in Clause 4.4 of CSA/ANSI ISO 27916:2019 (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).

(2) The methods used to estimate missing data and the amounts estimated as described in Clause 9.2.

(3) The approach and method for quantification utilized by the operator, including accuracy, precision, and uncertainties (see Clause 8 and Annex B).

(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).

(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 m_{stored}, 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.

(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 27916:2019 (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)), 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 27916:2019 (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).

(2) The initial containment assurance (see Clause 6.1.2).

(3) The monitoring program (see Clause 6.2).

(4) The quantification method to be used (see Clause 8 and Annex B).

(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).

(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.

(a) Additional terms and definitions are provided in Clause 3 of CSA/ANSI ISO 27916:2019 (incorporated by reference, see § 98.7).

(b) All references in this subpart preceded by the word Clause refer to the Clauses in CSA/ANSI ISO 27916:2019.

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