ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2023–0234; FRL–10246–02–OAR]

RIN 2060–AV83

Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is amending requirements that apply to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is owed under the Waste Emissions Charge. The EPA is also amending certain requirements that apply to the general provisions, general stationary fuel combustion, and petroleum and natural gas systems source categories of the Greenhouse Gas Reporting Rule to improve calculation, monitoring, and reporting of greenhouse gas data for petroleum and natural gas systems facilities. This action also establishes and amends confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these amendments.

DATES: This rule is effective January 1, 2025, except for § 98.233 (amendatory instruction 12), § 98.236 (amendatory instruction 16), and § 98.238 (amendatory instruction 19) which are effective July 15, 2024. The incorporation by reference of certain material listed in this final rule is approved by the Director of the Federal Register as of January 1, 2025.

ADDRESSES: The EPA has established a docket for this action under Docket ID. No. EPA–HQ–OAR–2023–0234. All documents in the docket are listed in the *https://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *https://www.regulations.gov* or in hard copy at the EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Jennifer Bohman, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460; telephone number: (202) 343–9548; email address: *GHGReporting@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Program (GHGRP) website, *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 final rule will also be available through the WWW. Following the Administrator's signature, a copy of this final rule will be posted on the EPA's GHGRP website at *https://www.epa.gov/ghgreporting.*

SUPPLEMENTARY INFORMATION:

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

Table 1. Examples of Affected Entities by Category

Category	North American Industry Classification System (NAICS)	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211120	Crude petroleum extraction.
	211130	Natural gas extraction.

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

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

AGR acid gas removal unit
AMLD Advanced Mobile Leak Detection
API American Petroleum Institute

ASTM American Society for Testing and Materials
AVO audio, visual, and olfactory
BOEM U.S. Bureau of Ocean Energy Management
BRE Bryan Research & Engineering
BSER best system of emissions reduction
Btu/scf British thermal units per standard cubic foot
CAA Clean Air Act
CBI confidential business information
CE combustion efficiency
CEMS continuous emissions monitoring system
CenSARA Central States Air Resources Agency
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e carbon dioxide equivalent
CRR cost-to-revenue ratio
DE destruction efficiency
DI&M directed inspection and maintenance
DOE Department of Energy (DOE)
DRE destruction and removal efficiency
e-GGRT electronic Greenhouse Gas Reporting Tool
EG emission guidelines
EIA U.S. Energy Information Administration
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
FAQ frequently asked question
FLIGHT Facility Level Information on Greenhouse gases Tool
FR Federal Register
FTIR Fourier transform infrared
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GOR gas to oil ratio
gpm gallons per minute
GRI Gas Research Institute
GT gas turbines
HHV higher heating value
ICR information collection request
ID identification
IRA Inflation Reduction Act of 2022
IVT Inputs Verification Tool
kg/hr kilograms per hour
LDAR leak detection and repair
LDC local distribution company
LNG liquefied natural gas
m meters
MDEA methyl diethanolamine
MEA monoethanolamine
MMBtu/hr million British thermal units per hour
MMscf million standard cubic feet
mt metric tons
$mtCO_2e$ metric tons carbon dioxide equivalent
N_2O nitrous oxide
NAICS North American Industry Classification System
NGLs natural gas liquids
NRU nitrogen recovery unit
NSPS new source performance standards
NYSERDA New York State Energy Research and Development Authority
O&M operation and maintenance
OCS AQS Outer Continental Shelf Air Quality System
OEL open-ended line
OEM original equipment manufacturer
OGI optical gas imaging
OMB Office of Management and Budget
OTM other test method
PBI proprietary business information
PHMSA U.S. Pipeline and Hazardous Materials Safety Administration
ppm parts per million
ppmv parts per million by volume
PRA Paperwork Reduction Act
PRD pressure relief device
psig pounds per square inch gauge
PTE potential to emit
RFA Regulatory Flexibility Act
RFI Request for Information
RICE reciprocating internal combustion engines
RY reporting year
SCADA supervisory control and data acquisition
scf standard cubic feet
scf/hr/device standard cubic feet per hour per device
TCEQ Texas Commission on Environmental Quality
THC total hydrocarbon
TOC total organic carbon
TSD technical support document
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
VISR Video Imaging Spectro-Radiometry
VOC volatile organic compound(s)
WEC waste emissions charge
WWW World Wide Web

Table of Contents

I. Background
  A. How is this preamble organized?
  B. Executive Summary
  C. Background on This Final Rule
  D. Legal Authority
  E. Relationship to Other Clean Air Act Section 136 Actions
  F. Relationship to Clean Air Act Section 111
II. Overview and Rationale for Final Amendments to 40 CFR Part 98, Subpart W
  A. Revisions To Address Potential Gaps in Reporting of Emissions Data for Specific Sectors
  B. Revisions To Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodologies
  C. Revisions to Reporting Requirements To Improve Verification and Transparency of the Data Collected
  D. Technical Amendments, Clarifications, and Corrections
III. Final Amendments to Part 98 and Summary of Comments and Responses
  A. General and Applicability Amendments
  B. Other Large Release Events
  C. New and Additional Emission Sources
  D. Reporting for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Industry Segments
  E. Natural Gas Pneumatic Device Venting and Natural Gas Driven Pneumatic Pump Venting
  F. Acid Gas Removal Unit Vents
  G. Dehydrator Vents
  H. Liquids Unloading
  I. Gas Well Completions and Workovers With Hydraulic Fracturing
  J. Blowdown Vent Stacks
  K. Atmospheric Storage Tanks
  L. Flared Transmission Storage Tank Vent Emissions
  M. Associated Gas Venting and Flaring
  N. Flare Stack Emissions
  O. Compressors
  P. Equipment Leak Surveys
  Q. Equipment Leaks by Population Count
  R. Offshore Production
  S. Combustion Equipment
  T. Leak Detection and Measurement Methods
  U. Industry Segment-Specific Throughput Quantity Reporting
  V. Other Final Minor Revisions or Clarifications
IV. Effective Date of the Final Amendments
  A. Amendments That Are Effective on January 1, 2025
  B. Amendments That Are Effective July 15, 2024
V. Final Confidentiality and Reporting Determinations for Certain Data Reporting Elements
  A. EPA's Approach To Assess Data Elements
  B. Final Confidentiality Determinations and Emissions Data Designations
  C. Final Reporting Determinations for Inputs to Emission Equations
VI. Impacts of the Final Amendments
  A. Cost Analysis
  B. Cost-to-Revenue Ratio Analysis
VII. Statutory and Executive Order Reviews
  A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
  B. Paperwork Reduction Act (PRA)
  C. Regulatory Flexibility Act (RFA)
  D. Unfunded Mandates Reform Act (UMRA)
  E. Executive Order 13132: Federalism
  F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
  G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
  H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use
  I. National Technology Transfer and Advancement Act and 1 CFR part 51
  J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
  K. Congressional Review Act (CRA)
  L. Judicial Review
  M. Determination Under CAA Section 307(d)
  N. Severability

I. Background

A. How is this preamble organized?

The first section of this preamble contains background information on the August 1, 2023 proposed amendments (88 FR 50282, hereafter referred to as ''2023 Subpart W Proposal'') and on this final rule, as well as a summary of the final revisions. 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 (hereafter referred to as ''part 98''), generally and 40 CFR part 98, subpart W (hereafter referred to as ''subpart W'') in particular. This section also discusses the EPA's legal authority to make confidentiality determinations for new or revised data elements corresponding to these amendments or for existing data elements for which the EPA is finalizing a new determination. Section II. of this preamble describes the types of amendments included in this final rulemaking and includes the rationale for each type of change. Section III. of this preamble contains detailed information on the revisions to 40 CFR part 98, subpart A (General Provisions), subpart C (General Stationary Fuel Combustion Sources) and subpart W. Section IV. of this preamble explains the effective date of the final revisions and how the revisions are required to be implemented in reporting year (RY) 2024 and RY2025 reports. Section V. of this preamble discusses the final confidentiality determinations for new or substantially revised (*i.e.,* requiring additional or different data to be reported) data reporting elements, as well as for certain existing data elements for which the EPA is finalizing a new determination. Section VI. of this preamble discusses the impacts of the amendments. Finally, section VII. of this preamble describes the statutory and Executive Order requirements applicable to this action.

B. Executive Summary

In August 2022, Congress passed, and President Biden signed, the Inflation Reduction Act of 2022 (IRA) into law. Section 60113 of the IRA amended the CAA by adding section 136, ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.'' CAA section 136(c), ''Waste Emissions Charge,'' directs the Administrator to impose and collect a charge on methane (CH_4) emissions that exceed statutorily specified waste emissions thresholds from owners or operators of applicable facilities that report more than 25,000 metric tons carbon dioxide equivalent ($mtCO_2e$) pursuant to the Greenhouse Gas Reporting Rule's requirements for the petroleum and natural gas systems source category (codified as subpart W in the EPA's Greenhouse Gas Reporting Rule regulations). Further, CAA section 136(h) requires that the EPA shall, within two years after the date of enactment of section 60113 of the IRA, revise the requirements of subpart W to ensure the reporting under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH_4 emissions (and waste emissions) from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136.

On August 1, 2023, the EPA proposed revisions to subpart W consistent with the authority and directives set forth in CAA section 136(h) as well as the EPA's authority under CAA section 114 in the 2023 Subpart W Proposal. The EPA proposed revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported by facilities to subpart W. The EPA also proposed several revisions to add new or revise existing calculation methodologies to improve the accuracy of reported emissions, incorporate additional empirical data and to allow owners and operators of applicable facilities to submit empirical emissions data that could appropriately demonstrate the extent to which a charge is owed in future implementation of CAA section 136, as directed by CAA section 136(h). For example, the EPA proposed new calculation methodologies for equipment leaks and natural gas pneumatic devices to allow for the use of direct measurement. The EPA also proposed several revisions to existing reporting requirements to collect data that would improve verification of reported data, ensure accurate reporting of emissions, and improve the transparency of reported data. For example, the EPA proposed to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, with most emissions and activity data for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting being disaggregated to at least the well-pad site and gathering and boosting site level, respectively. The EPA also proposed other technical amendments, corrections, and clarifications that would improve understanding of the rule. These revisions primarily included revisions of requirements to better reflect the EPA's intent or editorial changes. The 2023 Subpart W Proposal also indicated that the EPA would be undertaking one or more separate actions in the future to implement the remainder of CAA section 136.

The EPA is finalizing revisions to part 98 included in the 2023 Subpart W Proposal, with some changes made after consideration of public comments. The final amendments include new reporting requirements with some revisions from what was proposed for other large release events, produced water storage tanks, nitrogen removal units, drilling mud degassing, and crankcase venting. The final amendments expand the applicability of certain emission sources to new industry segments as proposed. The final amendments also include new calculation methods, with some revisions to those proposed, that provide measurement or monitoring survey options, including for the calculation of emissions from equipment leaks, combustion slip, crankcase venting, associated gas, compressors, natural gas pneumatic devices, and equipment leaks from components at transmission company interconnect metering and regulating stations, to allow reporters to use appropriate empirical data for these emission sources as an alternative to population emission factors. We are also revising calculation methods, with some revisions based on comments received, to improve the accuracy or clarity of the existing calculation methods. This action also finalizes confidentiality determinations for the reporting of data elements added or substantially revised in these final amendments, and for certain existing data elements for which no confidentiality determination has been made previously or for which the EPA proposed to revise the existing determination.

In some cases, and as further described in section III. of this preamble, the EPA is not taking final action in this final rule on certain proposed revisions included in the 2023 Subpart W Proposal. For example, after review of comments received in response to the proposed requirements for reporters in the Onshore Petroleum and Natural Gas Production, Natural Gas Distribution, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline industry segments that have ownership changes in subpart A, the EPA is not taking action at this time on the revisions to subpart A regarding responsibilities for revisions to reports submitted in the years before the ownership transactions. In consideration of the relationship between revisions to annual reports for prior years and implementation requirements for CAA section 136(c) proposed on January 26, 2024 (89 FR 5318) (hereafter referred to as the ''2024 WEC Proposal''), the EPA intends to consider those proposed revisions in coordination with the development of the WEC final rule and take action, if finalized, on these requirements at the same time. In some cases, we are not taking final action at this time on certain revisions to the calculation or monitoring methodologies that would have revised how data are collected. For example, after review and consideration of the comments received in response to the proposed requirements for flares, we are not finalizing requirements to use continuous flow monitors or continuous parametric monitoring and continuous composition analyzers or quarterly sampling to determine flow and composition, respectively, of gas routed to flares. In several cases, we are also not taking final action at this time on proposed revisions to add reporting requirements. For example, we are not finalizing certain proposed reporting requirements for other large release events when the reporter receives a third-party notification because all Super-Emitter Program notifications will come from the EPA and the EPA will already have the information proposed to be reported.

Some of the final amendments, particularly those that allow reporters to choose from additional calculation methodologies and submit empirical emissions data will be effective immediately as optional methodologies. These amendments will apply to reports submitted by current reporters that are submitted in calendar year 2025 and subsequent years (*i.e.,* starting with reports submitted for RY2024 by March 31, 2025). The remaining final amendments will become effective on January 1, 2025. Those final revisions, which apply to both existing and new reporters, will be first implemented for reports prepared for RY2025 and submitted by March 31, 2026. Reporters who are newly subject to the rule will be required to implement all requirements to collect data, including any required monitoring and recordkeeping, on January 1, 2025.

These final amendments are anticipated to result in an overall increase in burden for part 98 reporters in cases where the amendments expand current applicability, add or revise reporting requirements, or require additional emissions data to be reported. The final revisions will affect approximately 567 new reporters and 2,510 existing reporters. The incremental implementation labor costs are $169.4 million per year over the next three years (RY2025 through RY2027), for a total of $508.3 million for the three years. There is an additional incremental annualized burden of $14.1 million for operation and maintenance (O&M) costs in RY2025 and in each subsequent year (RY2026 and RY2027), which reflects changes to monitoring for 2,510 existing reporters and the 567 additional reporters.

Labor costs increased from $41.4 million per year at proposal to $169.4 million per year at final, based in part on consideration of comments received on the estimated labor hours needed to comply with these amendments at proposal. As detailed in section VI.A. of this preamble and the *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule,* those labor hour estimates have been revised, leading to higher labor costs.

C. Background on This Final Rule

This final action builds on previous part 98 rulemakings. The Greenhouse Gas 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] Although reporting requirements for petroleum and natural gas systems were originally proposed to be part of part 98 (75 FR 16448, April 10, 2009), the final October 2009 rulemaking did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA re-proposed subpart W in 2010 (75 FR 18608; April 12, 2010), and a subsequent final rulemaking was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458) (hereafter referred to as the ''2010 Final Rule''). Following promulgation, the EPA finalized several technical and clarifying amendments to subpart W (76 FR 22825, April 25, 2011; 76 FR 53057, August 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 73866, November 29, 2011; 76 FR 80554, December 23, 2011; 77 FR 48072, August 13, 2012; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014; 80 FR 64262, October 22, 2015; and 81 FR 86490, November 30, 2016). These amendments generally added or revised requirements in subpart W, including revisions that were intended to improve quality, clarity, and consistency across the calculation, monitoring, and data reporting requirements, and to finalize confidentiality and reporting determinations for data elements reported under the subpart.

More recently, the EPA proposed amendments to subpart W on June 21, 2022 (87 FR 36920) (hereafter referred to as the ''2022 Proposed Rule''), including technical amendments to improve the quality and consistency of the data collected under the rule and resolve data gaps, amendments to streamline and improve implementation, and revisions to provide additional flexibility in the calculation methods and monitoring requirements for some emission sources. The 2022 Proposed Rule was developed prior to the enactment of the Inflation Reduction Act, which was signed into law on August 16, 2022, and its direction in CAA section 136(h) to revise subpart W. Consequently, in developing the 2023 Subpart W Proposal, the EPA considered the proposed amendments to subpart W from the 2022 Proposed Rule as well as the concerns and information submitted by commenters in response to that proposal. In the 2023 Subpart W Proposal, the EPA proposed to revise the subpart W provisions, including both (1) updates to the proposed revisions to subpart W that were in the 2022 Proposed Rule as well as (2) additional proposed revisions to comply with CAA section 136(h). The preamble to the 2023 Subpart W Proposal explained that the EPA did not intend to finalize the revisions to subpart W that were proposed in the 2022 Proposed Rule and that the final amendments to subpart W would include consideration of public comments on the 2023 Subpart W Proposal.

Additionally, the EPA opened a non-regulatory docket on November 4, 2022, and issued a Request for Information (RFI) seeking public input to inform program design related to CAA section 136.[2] As part of this request, the EPA sought input on revisions that should be considered related to subpart W. The comment period closed on January 18, 2023.

The EPA is finalizing amendments and confidentiality determinations in this action, with certain changes from

[1] Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128.

[2] Docket ID No. EPA–HQ–OAR–2022–0875.

the 2023 Subpart W Proposal following consideration of comments submitted and based on the EPA's updated assessment. The revisions reflect the EPA's efforts to improve calculation, monitoring, and reporting of greenhouse gas data for petroleum and natural gas systems facilities and to ensure that reporting is based on empirical data, accurately reflects total methane emissions and waste emissions from applicable facilities, and allows owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is owed under the Waste Emissions Charge. Responses to major comments submitted on the proposed amendments from the 2023 Subpart W Proposal considered in the development of this final rule can be found in section III. of this preamble. Documentation of all comments received as well as the EPA's responses can be found in the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule,* available in the docket to this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

While this final rule complies with and is consistent with directives in CAA section 136(h), this final rule does not address implementation of other portions of CAA section 136 (section 60113 of the Inflation Reduction Act), ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.'' The EPA noted in the preamble to the 2023 Subpart W Proposal that we intend to issue one or more separate actions to implement other requirements of CAA section 136, which could include revisions to certain requirements of subpart W for implementation purposes. Subsequently, the EPA published the 2024 WEC Proposal to implement CAA section 136(c), ''Waste Emissions Charge,'' or ''WEC,'' on January 26, 2024 (89 FR 5318).[3]

D. Legal Authority

The EPA is finalizing these rule amendments under its existing CAA authority provided in CAA section 114 and under its newly established authority provided in CAA section 136, as applicable. As noted in the preamble to the proposed rule for this rulemaking and in the preamble to the 2009 Final Rule (74 FR 56264, October 30, 2009), the EPA has consistently applied its authority under CAA section 114(a)(1) for over a decade to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out of a variety of CAA provisions. Thus, when promulgating amendments to the Greenhouse Gas Reporting Rule (40 CFR part 98), the EPA has assessed the reasonableness of requiring the information to be provided and explained how the data are relevant to the EPA's ability to carry out the provisions of the CAA. See the preambles to the proposed Greenhouse Gas Reporting Rule (74 FR 16448, April 10, 2009) and the 2009 Final Rule for further information. Additionally, in enacting CAA section 136, Congress implicitly recognized the EPA's appropriate use of CAA authority in promulgating the GHGRP. As noted in section I.B. of this preamble, the provisions of CAA section 136 reference and are in part based on the Greenhouse Gas Reporting Rule requirements under subpart W for the petroleum and natural gas systems source category and require further revisions to subpart W for purposes of supporting implementation of section 136. Under CAA section 136(h), Congress directed the Administrator to revise the requirements of subpart W to ensure that reporting of CH_4 emissions under subpart W (and corresponding waste emissions charges under CAA section 136) is based on empirical data, accurately reflects the total CH_4 emissions (and waste emissions) from applicable facilities, and allows owners and operators to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed under CAA section 136. Under CAA section 136, an ''applicable facility'' is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution). The revisions being finalized are consistent with these directives, ensuring that (1) reporting of methane emissions under subpart W are based on empirical data, (2) accurately reflect total methane emissions (and waste emissions) and (3) allow owners and operators to submit appropriate empirical data. The EPA appropriately applied its authority in this rulemaking in a manner consistent with CAA section 114 and the directives under CAA section 136. See section II. of this preamble for discussion of the rationale for these revisions, which includes that they can be used to support carrying out a range of future climate change policies and regulations under the CAA, including but not limited to information relevant to carrying out CAA section 136, provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs under the CAA, and see also section III. of this preamble and the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule,* available in the docket to this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234), for further detail on the revisions and their supporting rationale.

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

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

E. Relationship to Other Clean Air Act Section 136 Actions

The IRA adds authorities under CAA section 136 to reduce CH_4 emissions from the oil and gas sector. It accomplishes this in multiple ways. First, it provides incentives for CH_4 mitigation and monitoring. Second, it establishes a waste emissions charge for applicable facilities that exceed statutorily specified thresholds that vary by industry segment and are determined by the amount of natural gas or oil sent to sale. Third, CAA section 136(h) requires the EPA to revise subpart W. The first and second listed aspects of CAA section 136 are outside the scope of this rulemaking.

CAA section 136 provides $1.55 billion in incentives for CH_4 mitigation and monitoring, including through grants, rebates, contracts, loans, and other activities. Of these funds, at least $700 million is allocated to activities at

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

marginal conventional wells. There are several potential uses of funds. Use of funds can include financial and technical assistance to owners and operators of applicable facilities to prepare and submit GHG reports under subpart W. Financial assistance can also be provided for CH_4 emissions monitoring authorized under CAA section 103 subsections (a) through (c). Additionally, financial and technical assistance can be provided to: reduce CH_4 and other GHG emissions from petroleum and natural gas systems, including to mitigate legacy air pollution from petroleum and natural gas systems; improve climate resilience of communities and petroleum and natural gas systems; improve and deploy industrial equipment and processes that reduce CH_4 and other GHG emissions and waste; support innovation in reducing CH_4 and other GHG emissions and waste from petroleum and natural gas systems; permanently shut in and plug wells on non-Federal land; and mitigate health effects of CH_4 and other GHG emissions and legacy air pollution from petroleum and natural gas systems in low-income and disadvantaged communities, and support environmental restoration.

The EPA has partnered with the Department of Energy (DOE) to administer financial assistance under the Methane Emission Reduction Program. In 2023, DOE announced and conditionally awarded $350 million in funds to fourteen states to measure and reduce methane emissions from low-producing conventional wells.[4] In February 2024, the EPA and DOE announced intent to open a competitive funding opportunity to a broader range of applicants to reduce and monitor emissions from the oil and gas industry.[5]

The EPA and DOE are moving expeditiously to implement the incentives for CH_4 mitigation and monitoring and anticipate making announcements regarding next steps; however, as noted, those steps are outside the scope of this rulemaking. As relevant data become available from the funded activities, the EPA will consider how they can be used to improve reporting under subpart W.

CAA section 136(c) provides that the Administrator shall impose and collect a charge on CH_4 emissions that exceed an applicable waste emissions threshold under CAA section 136(f) from an owner or operator of an applicable facility that reports more than 25,000 $mtCO_2e$ per year pursuant to subpart W. CAA section 136 provides various flexibilities and exemptions relating to the waste emissions charge. The EPA proposed to add 40 CFR part 99 to implement the WEC in the 2024 WEC Proposal and has provided an opportunity for public comment on that proposal; therefore, as noted, implementation of the WEC is outside the scope of this rulemaking.

As noted earlier, CAA section 136(h) requires revisions to subpart W. The purpose of this final action is to meet directives set forth in CAA section 136(h) and to amend certain requirements that apply to the general provisions, general stationary fuel combustion, and petroleum and natural gas systems source categories of the Greenhouse Gas Reporting Rule to improve the calculation, monitoring, and reporting of greenhouse gas data for petroleum and natural gas systems facilities consistent with the EPA's authority.

F. Relationship to Clean Air Act Section 111

The EPA had also identified areas where additional revisions to part 98 would better align subpart W requirements with recently promulgated requirements in 40 CFR part 60 and part 62, allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs (and thereby limit burden), and improve the emission calculations reported under subpart W. On November 15, 2021 (86 FR 63110), the EPA proposed under CAA section 111(b) standards of performance for certain new, reconstructed, and modified oil and natural gas sources (40 CFR part 60, subpart OOOOb) (hereafter referred to as ''NSPS OOOOb''), as well as emissions guidelines under CAA section 111(d) for certain existing oil and natural gas sources (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''). On December 6, 2022, the EPA issued a supplemental proposal to update, strengthen and expand the standards proposed on November 15, 2021 (87 FR 74702). On March 8, 2024, the final NSPS OOOOb and EG OOOOc rule published in the **Federal Register** (89 FR 16820). While the standards in NSPS OOOOb will directly apply to new, reconstructed, and modified sources, the final EG OOOOc does not impose binding requirements directly on sources; rather it contains 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 CH_4 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. In addition, a Federal plan could apply to sources located on Tribal lands where the tribe does 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. 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 do not directly apply to sources, the final amendments to subpart W reference 40 CFR part 62.

We are finalizing revisions to certain requirements in subpart W relative to the requirements finalized for NSPS OOOOb and the presumptive standards in EG OOOOc (which will inform the standards to be developed and codified at 40 CFR part 62). The final amendments in this rule will allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs. These final standards will limit burden for subpart W facilities with affected sources that are also required to comply with the NSPS OOOOb or a state or Federal plan in 40 CFR part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods.

II. Overview and Rationale for Final Amendments to 40 CFR Part 98, Subpart W

As discussed in section I. of this preamble, in August 2022, Congress

[4] U.S. Environmental Protection Agency. (2023, December 15). Biden-Harris Administration Announces $350 Million to 14 States to Reduce Methane Emissions from Oil and Gas Sector as Part of Investing in America Agenda [Press Release]. *https://www.epa.gov/newsreleases/biden-harris-administration-announces-350-million-14-states-reduce-methane-emissions.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[5] U.S. Environmental Protection Agency. (2024, February 9). EPA and DOE announce intent to fund projects to reduce methane emissions from the oil and natural gas sectors as part of President Biden's Investing in America agenda [Press Release]. *https://www.epa.gov/newsreleases/epa-and-doe-announce-intent-fund-projects-reduce-methane-emissions-oil-and-natural-gas.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

passed, and President Biden signed, the IRA into law. Section 60113 of the IRA amended the CAA by adding section 136, ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.'' CAA section 136(h) requires that the EPA shall, within two years of the enactment of that section of the IRA, revise the requirements of subpart W to ensure the reporting under that subpart and calculation of charges under CAA section 136(e) and (f) are based on empirical data, accurately reflect the total CH_4 emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner prescribed by the Administrator, to demonstrate the extent to which a charge is owed. CAA section 136(d) defines the term ''applicable facility'' as a facility within the following industry segments as defined in subpart W: offshore petroleum and natural gas production, onshore petroleum and natural gas production, onshore natural gas processing, onshore gas transmission compression, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline.

Empirical data can be defined as data that are collected by observation and experiment. There are many forms of empirical data that can be used to quantify GHG emissions. For purposes of this action, the EPA interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of CH_4 emissions (*e.g.,* leak surveys) or measurement of associated parameters (*e.g.,* flow rate, pressure), and published data. The EPA reviewed available empirical data methods for accuracy and appropriateness for calculating annual unit or facility-level GHG emissions. The review included both the evaluation of technologies and methodologies already incorporated in subpart W for measuring and reporting annual source- and facility-level GHG emissions and the evaluation of the accuracy of potential alternative technologies and methodologies, with a focus on CH_4 emissions due to the directive in CAA section 136(h). The EPA also reviewed technologies and methodologies suggested by commenters during the public comment period for the 2023 Subpart W Proposal.

Currently, subpart W specifies emission source types to be reported for each industry segment and provides methodologies to calculate emissions from each source type, which are then summed to generate the total subpart W emissions for the facility. Current calculation methods can be grouped into five categories: (1) direct emissions measurement; (2) combination of measurement and engineering calculations; (3) engineering calculations; (4) leak detection and use of a leaker emission factor; and (5) population count and population emission factors. Subpart W emission factors (both population and leaker emission factors) include both those developed from published empirical data and those developed from site-specific data collected by the reporting facility. The EPA developed the current subpart W monitoring and reporting requirements to use the most appropriate monitoring and calculation methods, considering both the accuracy of the emissions calculated by the proposed method and the size of the emission source based on the methods and data available at the time of the applicable rule promulgation. Considering the directives set forth in CAA section 136, the EPA re-evaluated the existing methodologies to determine if they are likely to accurately reflect CH_4 and waste emissions at an individual facility, whether the existing methodologies used empirical data, and whether the existing methodologies should be modified or replaced or if additional optional calculation methods were available and appropriate and should be added to meet CAA section 136 directives. Even in cases where the EPA determined that an existing method that is not based on direct measurement or emission monitoring provides a reasonably accurate calculation of emissions for a facility, we also reviewed whether an appropriate direct emission measurement or emission monitoring method could be added to subpart W, if one was not already available, to give owners and operators the opportunity to submit empirical data. For example, intermittent bleed pneumatic devices are designed to vent during actuation only, but these devices are known to often malfunction and operate incorrectly, which causes them to release gas to the atmosphere when idle, leading to high degree of variance in emissions from pneumatic devices between facilities (see the technical support document *Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Final Rule—Petroleum and Natural Gas Systems,* hereafter referred to as the ''final subpart W TSD,'' available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234, for more information). For this example, the final amendments add several new optional calculation methods to allow reporters to account for the variability. The EPA also evaluated whether there were gaps in the emission source types reporting CH_4 emissions under subpart W and whether there were methodologies available to calculate those emissions.

The final amendments include:

• Revisions to expand reporting to include new emission sources, in order to accurately reflect total CH_4 emissions reported to the GHGRP.

• Revisions to add emissions calculation methodologies to expand options to allow owners and operators to submit empirical emissions data and improve the accuracy of reported emission data, including to expand options to allow owners and operators to submit empirical emissions data where the EPA determined appropriate methods were available.

• Revisions to refine existing emissions calculation methodologies to reflect an improved understanding of emissions, to incorporate additional empirical data or to incorporate more recent research on GHG emissions to improve the accuracy of reported emission data.

The EPA has also identified additional areas where revisions to part 98 will improve the EPA's ability to verify the accuracy of reported emissions and improve data transparency and alignment with other EPA programs and regulations. The EPA also identified areas where additional data or revised data elements may be necessary for future implementation of the Waste Emissions Charge under CAA section 136. The final revisions include:

• Revisions to report emissions and certain associated data from emission sources at facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments at the site level or well level instead of at the basin level, sub-basin level, or county level.

• Addition of data elements related to emissions from plugged wells.

• Addition or clarification of throughput-related data elements for subpart W industry segments.

• Revisions to data elements or recordkeeping where the current requirements are redundant or alternative data are more appropriate for verification of emission data.

• Revisions that provide additional information for reporters to better or more fully understand their compliance obligations, revisions that emphasize the EPA's intent for requirements that reporters appear to have previously misinterpreted to ensure that accurate data are being collected, and editorial corrections or harmonizing changes that will improve the public's understanding of the rule.

Sections II.A. through II.D. of this preamble describe the above changes in more detail and provide the EPA's rationale for the changes included in each category. Additional details for the specific amendments for each subpart are included in section III. of this preamble.

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

We are finalizing several amendments to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported per facility to subpart W. These final amendments ensure that the reporting under subpart W accurately reflects the total CH_4 emissions and waste emissions from applicable facilities, as directed by CAA section 136(h). In particular, based on recent analyses such as those conducted for the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (U.S. GHG Inventory), and data newly available from atmospheric observations, we have become aware of potentially significant sources of emissions for which there are no current emission estimation methods or reporting requirements within part 98. For subpart W, we are finalizing the addition of calculation methodologies and requirements to report GHG emissions for several additional sources. We are adding 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 covers events such as storage wellhead leaks, well blowouts,[6] and other large, atypical release events and will apply to all types of facilities subject to subpart W. Reporters will calculate GHG emissions using measurement data or engineering estimates of the amount of gas released and using measurement data, if available, or process knowledge (best available data) to estimate the composition of the released gas. We are also finalizing the addition of calculation methodologies and requirements to report GHG emissions for several other new emission sources, including nitrogen removal units, produced water tanks, mud degassing, and crankcase venting. None of these sources are currently accounted for in subpart W, and the EPA is adding them because they are likely to have a meaningful impact on reported total facility CH_4 emissions. We are also finalizing revisions to the existing methodologies and adding new measurement-based methodologies, consistent with section II.B. of this preamble, for determining combustion emissions from RICE and GT to account for combustion slip, which is not currently accounted for under the existing calculation methodologies for combustion emissions. We are also finalizing requirements to report existing emission sources for certain subpart W industry segments under additional industry segments. For example, we are requiring liquefied natural gas (LNG) import/export facilities to begin calculating and reporting emissions from acid gas removal unit (AGR) vents. Additional details of these types of final changes may be found in section III. of this preamble.

B. Revisions To Add New Emissions Calculation Methodologies or Improve Existing Emissions Calculation Methodologies

We are finalizing several revisions to add new or revise existing calculation methodologies to improve the accuracy of emissions data reported to the GHGRP, incorporate additional empirical data, and to allow owners and operators of applicable facilities to submit empirical emissions data that appropriately demonstrate the extent to which a charge is owed in future implementation of CAA section 136, as directed by CAA section 136(h). Subpart W specifies emission source types to be reported for each industry segment and provides methodologies to calculate emissions from each source type, which are then summed to generate the total subpart W emissions for the facility. Considering the directives set forth in CAA section 136, the EPA re-evaluated the existing methodologies for each source to determine if they are likely to accurately reflect CH_4 and waste emissions at an individual facility, whether the existing methodologies used empirical data (*e.g.,* direct emissions measurements or monitoring of CH_4 emissions; measurement of associated parameters), and whether the existing methodologies should be modified or replaced or if new optional calculation methodologies should be added to meet CAA section 136 directives. A summary list of the final emissions sources to be reported with the corresponding monitoring and emissions calculation methods is available in the final subpart W TSD, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. Many sources in subpart W already have or require calculation methodologies that use direct emission measurement, including AGR vents, large reciprocating compressor rod packing vents, large compressor blowdown vent valve leaks, and large compressor blowdown vent (unit isolation valve leaks), the latter three when leakage is detected via screening. In these final amendments, the EPA is finalizing the addition of new calculation methodologies to allow for the use of direct measurement, including for the calculation of emissions from equipment leaks, combustion slip, crankcase venting, associated gas, compressors, natural gas pneumatic devices, and equipment leaks from components at transmission company interconnect metering and regulating stations. The EPA is also finalizing new calculation methodologies to allow for the development of facility-specific emission factors for equipment leaks based on data collected from direct measurement at the facility. The EPA is also finalizing the option to use advanced technologies to measure data that are inputs to emissions calculations for flares and completions and workovers with hydraulic fracturing. These final amendments will provide owners and operators the opportunity to submit appropriate empirical data in their subpart W annual reports. We also reviewed whether some optional calculation methodologies would be appropriate to allow in RY2024, so that owners and operators would have the opportunity to submit appropriate empirical data in line with existing subpart W. As discussed in section IV. of this preamble, we are finalizing the addition of a number of new optional calculation methodologies that are relevant to existing subpart W sources effective July 15, 2024.

Similar to the 2016 amendments to align subpart W requirements with certain requirements in 40 CFR part 60, subpart OOOOa (hereafter referred to as ''NSPS OOOOa'') (81 FR 86500,

[6] We are finalizing as proposed the provision to define a well blowout in 40 CFR 98.238 as a complete loss of well control for a long duration of time resulting in an emissions release.

November 30, 2016), we are also finalizing revisions to certain requirements in subpart W relative to the requirements finalized for NSPS OOOOb and the presumptive standards in EG OOOOc (which will inform the standards to be developed and codified at 40 CFR part 62). As in the 2016 rule, the final amendments also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs. These final standards will limit burden for subpart W facilities with affected sources that are also required to comply with the NSPS OOOOb or a state or Federal plan in 40 CFR part 62 implementing EG OOOOc by allowing them to use data derived from the implementation of the NSPS OOOOb to calculate emissions for the GHGRP rather than requiring the use of different monitoring methods. Consistent with that goal, the final amendments to subpart W reference the final version of the method(s) in the NSPS OOOOb and EG OOOOc. These amendments also improve the emission calculations reported under the GHGRP by requiring the use of facility-collected measurement or survey data to calculate emissions where available and appropriate. Specifically, we are finalizing amendments to the subpart W calculation methodologies for atmospheric pressure storage tanks, flares, centrifugal and reciprocating compressors, and equipment leak surveys related to the final NSPS OOOOb and presumptive standards in EG OOOOc, and we are finalizing new reporting requirements for ''other large release events'' as defined in subpart W that reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62. These final amendments are described in sections III.B., N., O., and P. of this preamble; the effective dates of these final amendments are discussed in section IV. of this preamble. As reflected in section IV. of this preamble, the provisions of these final amendments that reference the NSPS OOOOb and approved state plans or applicable Federal plan in 40 CFR part 62 do 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 have the option to comply with the calculation methodologies that are required for sources subject to NSPS OOOOb or 40 CFR part 62, or they may comply instead with the applicable provisions of subpart W that apply to sources not subject to NSPS OOOOb or 40 CFR part 62. For example, for flare sources, subpart W facilities have the option to comply with the flare monitoring requirements in NSPS OOOOb even if the source is not yet subject to or will not be subject to those provisions. For the ''other large release events'' source category, emissions from other large release events are required to be calculated and reported starting in Reporting Year (RY) 2025; the requirements to calculate and report these emissions are not dependent on whether a source is subject to NSPS OOOOb or 40 CFR part 62. The specific changes that we are finalizing, as described in this section, are described in detail in section III. of this preamble.

We are also finalizing 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 revisions will reduce reporter errors. In other cases, we are revising the emissions estimation methodologies to incorporate recent studies on GHG emissions or formation that reflect updates to scientific understanding of GHG emissions sources. The final amendments will improve the quality and accuracy of the data collected under the GHGRP.

We are also finalizing revisions to several existing calculation methodologies to incorporate empirical data obtained at the facility. Emissions can be reliably calculated for sources such as atmospheric storage tanks and glycol dehydrators using standard engineering first principle methods such as those available in API 4697 E&P Tanks [7] and GRI–GLYCalc™ [8] when based on actual operating conditions. Using such software also addresses safety concerns that are associated with direct emissions measurement from these sources in certain circumstances. For example, sometimes the temperature of the emissions stream for glycol dehydrator vent stacks is too high for operators to safely measure emissions. Currently these methods in subpart W allow for use of best available data for all inputs to the model. However, the EPA has noted that in some cases, such as with reporting of emissions from some dehydrators, the data used to calculate emissions are not based on actual operating conditions but instead based on ''worst-case scenarios'' or other estimates. In these final amendments, for large glycol dehydrators and AGRs, we are requiring that certain input parameters be based on actual measurements at the unit level in order to ensure that emissions calculations are based on actual operating conditions and to improve the accuracy of the reported emissions for these sources.

In order to improve the accuracy of the data collected under the GHGRP, we are finalizing revisions to emission factors where improved measurement data has become available or we have received additional information from stakeholders. Some of the calculation methodologies provided in the GHGRP rely on the use of emission factors that are based on published empirical data. Default emission factors based on representative empirical data can provide a reasonably accurate estimate of facility-level emissions. The final rule includes revisions to emission factors for a number of emission source types where we have received or identified updated, representative measurement data.

We are finalizing updated emission factors for natural gas pneumatic devices, 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, and compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities in subpart W. The revised emission factors are more representative of GHG emissions sources and will improve the overall accuracy of the emission data collected under the GHGRP. Additional details of these types of final revisions may be found in section III. of this preamble.

As noted in section II.A. of this preamble, we are adding 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. Under these provisions in this final rule, the EPA is also finalizing the inclusion of emissions from other large emissions events and super-emitters in the subpart W reporting program. This addition will directly address the concerns identified by a multitude of studies about the

[7] E&P Tanks v3.0 software and the user guide (Publication 4697) formerly available from the American Petroleum Institute (API) website.

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

contribution of super-emitters to total emissions and help to ensure the completeness and accuracy of emissions reporting data. Advanced measurement approaches that have demonstrated their ability to detect, attribute the source at least to site-level, and accurately quantify emission rates of such events are a central feature of the finalized changes. Some advanced measurement approaches have a demonstrated ability to provide data useful for quantifying emissions from very large, distinct emission events, such as production well blowouts. In the U.S. GHG Inventory, the EPA has already incorporated emissions estimates developed from such approaches to calculate emissions from well blowouts.[9] In this final rule, we are requiring facilities to consider notifications of super-emitter emissions event under the super-emitter provisions of NSPS OOOO/OOOOa/OOOOb at 40 CFR 60.5371, 60.5371a, and 60.5371b or the applicable approved state plan or applicable Federal plan and calculate the associated emissions when they exceed the final threshold of 100 kg/hr CH4 if they are not already appropriately accounted for under another source category in subpart W. We expect that under the final methodology for other large release events, data from some advanced measurement approaches, including data derived from equipment leak and fugitive emissions monitoring using advanced screening methods conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62, in combination with other empirical data, could be used by reporters to calculate the total emissions from these events and/or estimate duration of such an event.

The EPA received numerous comments requesting that the EPA allow for the use of advanced technologies to quantify emissions from other emission sources in subpart W beyond ''other large release events.'' In response, we reviewed advanced measurement approaches that utilize information from satellite, aerial, drone, vehicle, and stationary platforms to detect and/or quantify methane emissions from petroleum and natural gas systems at different spatial and temporal scales for their potential use in estimating emissions of specific sources for the purposes of subpart W reporting. Advanced technologies have been a focus for research and emission monitoring strategies, and several technologies have progressed in recent years to provide valuable CH4 emission data. The spatial and temporal resolution of emission estimates varies widely, however, depending on the technology and platform.

Two general categories of advanced technologies were evaluated for their potential use in subpart W: remote sensing (*e.g.,* satellite, aerial) and continuous monitoring systems, which typically use gas sensors and/or imaging coupled with proprietary algorithms to detect emissions and/or provide emission rates. Remote sensing approaches typically use aerial or satellite-deployed infrared spectroscopy to survey areas for methane emission plumes. For remote sensing technologies, the size of the area monitored is typically inversely related to the detection levels. Satellite remote sensing technologies are deployed at altitudes of 400 to 800 kilometers and currently have CH4 detection limits of approximately 50 to 25,000 kilograms per hour (kg/hr),[10] and high altitude remote sensing (by airplane) measure at altitudes of 168 to 12,000 meters (m) with current CH4 detection limits of approximately 1 to 50 kg/hr.[11] We find that existing remote sensing approaches are suitable to supplement the other requirements for periodic measurement and calculation of annual emissions for large discrete events, as they are capable of having suitable detection limits for the identification of the presence of large anomalous events. However, our assessment at this time is that existing remote sensing approaches currently are not able to appropriately estimate annual emissions from other sources under subpart W. Most remote sensing measurements are taken over limited durations (a few minutes to a few hours) typically during the daylight hours and limited to times when specific meteorological conditions exist (*e.g.,* no cloud cover for satellites; specific atmospheric stability and wind speed ranges for aerial measurements). These direct measurement data taken at a particular moment in time may not be representative of the annual CH4 emissions from the facility, given that many emissions are episodic. If emissions are found during a limited duration sampling, that does not necessarily mean they are present for the entire year. And if emissions are not found during a limited duration sampling, that does not necessarily mean significant emissions are not occurring at other times. Extrapolating from limited measurements to an entire year therefore creates risk of either over or under counting actual emissions.

Additionally, while advanced measurement methods based on remote sensing, including satellite and aerial methods, have proven their ability to identify and measure large emissions events, their detection limits may be too high to detect emissions from sources with relatively low emission rates.[12] The data provided by some of these technologies are at large spatial scales, with limited ability to disaggregate to the facility- or emission source-level and have high minimum detection limits. So while these technologies can provide very useful information about emissions during snapshots in time, and thus help to greatly improve the completeness and accuracy of emission reporting, with the current state of these technologies they generally cannot by themselves estimate annual emissions.

[9] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2020: Updates for Anomalous Events including Well Blowout and Well Release Emissions.* April 2022. Available at *https://www.epa.gov/system/files/documents/2022-04/2022_ghgi_update_-_blowouts.pdf* and in the docket for this rulemaking, Docket ID. No. EPA-HQ-OAR-2023-0234.

[10] See GHGSat. GHGSat Media Kit. (2021). Available at *https://www.ghgsat.com/upload/misc/GHGSAT_MEDIAKIT_2021.pdf;* Pandey, S., *et al.* ''Satellite observations reveal extreme methane leakage from a natural gas well blowout.'' *Proceedings of the National Academy of Sciences,* Vol. 116, no. 52. Pp. 26376–26381, December 16, 2019, available at *https://doi.org/10.1073/pnas.1908712116;* Jacob, D.J., *et al.* ''Quantifying methane emissions from the global scale down to point sources using satellite observations of atmospheric methane.'' *Atmospheric Chemistry and Physics, Vol.* 22, Issue 14, pp. 9617–9646, July 29, 2022, available at *https://doi.org/10.5194/acp-22-9617-2022;* Anderson, V., *et al.* ''Technological opportunities for sensing of the health effects of weather and climate change: a state-of-the-art-review.'' *International Journal of Biometeorology,* Vol. 65, Issue 6, pp. 779–803, January 11, 2021, available at *https://doi.org/10.1007/s00484-020-02063-z.* The documents are also available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[11] See Conrad, B.M., Tyner, D.R. & Johnson, M.R. ''Robust probabilities of detection and quantification uncertainty for aerial methane detection: Examples for three airborne technologies.'' *Remote Sensing of Environment,* Vol. 288, p. 113499, available at *https://doi.org/10.1016/j.rse.2023.113499.* 2023; Duren, R.M., et al. ''California's methane super-emitters.'' *Nature,* Vol. 575, Issue 7781, pp. 180–184, available at *https://doi.org/10.1038/s41586-019-1720-3.* 2019; Thorpe, A.K., *et al.* ''Airborne DOAS retrievals of methane, carbon dioxide, and water vapor concentrations at high spatial resolution: application to AVIRIS–NG.'' *Atmos. Meas. Tech.,* 10, 3833–3850, available at *https://doi.org/10.5194/amt-10-3833-2017.* 2017; Staebell, C., *et al.* ''Spectral calibration of the MethaneAIR instrument.'' *Atmospheric Measurement Techniques,* Vol. 14, Issue 5, pp. 3737–3753, available at *https://doi.org/10.5194/amt-14-3737-2021.* 2021. The documents are also available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

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

Therefore, this rule finalizes allowing the use of these advanced measurement methods based on remote sensing to supplement the other requirements for periodic measurement and calculation of annual emissions for other large release events, as described in section III.B. of this preamble.

Continuous monitoring systems, which typically use one or more stationary sensors and/or imagers located on or near sites to frequently detect and/or quantify anomalous emissions, can have significant value for detecting anomalous emissions but are less suitable for the annual quantification that is required for purposes of the Greenhouse Gas Reporting Program and satisfying Congress's directive in the Inflation Reduction Act. Although these systems may continuously collect methane concentration data, emissions data from monitored sites are not typically continuous because methane emission plumes may not reach sensors or visual images may not detect plumes under certain meteorological and operational conditions. Recent studies evaluating the performance of several continuous monitors have reported that these systems can provide valuable data for detecting anomalous emissions (and generally faster than survey methods) and determining event duration, but typically have high uncertainty in quantifying total emissions.[13] Therefore, we determined that continuous monitoring systems currently are not suitable for quantifying emissions for subpart W reporting on their own but may provide data on the duration of large release events. Further discussion of our review of advanced technologies is available in the final subpart W TSD, available in the docket for this rulemaking.

Based on our review, we are finalizing the use of advanced measurement data, including both remote sensing technologies and continuous monitoring systems, to help identify and quantify super-emitter and other large emissions events. Commenters also requested that the EPA allow for the adoption of advanced technologies without having to go through a new rulemaking process, similar to the technology verification programs developed under the NSPS OOOOb and EG OOOOc even though many commenters acknowledged that with the current state of advanced technologies, it is not possible to accurately quantify annual emissions at the individual source level, particularly at low emission rates as would be needed to accurately quantify many subpart W sources. However, for reasons discussed below, this final rule does not include a general provision to incorporate the use of advanced measurement approaches at this time except in certain cases, such as large release events. It is worth noting that the NSPS OOOOb and EG OOOOc (and the technologies that are verified under that program), are focused on detecting leaks or identifying anomalous emissions that exceed certain action levels, which is more straightforward than accurately quantifying source emission rates over annual time periods. Furthermore, the EPA is not aware of a standardized protocol to accurately extrapolate from either continuous or discrete remote sensing measurement data to an annual, facility-level emission total. At this point in time, there are still many outstanding research questions associated with how best to combine advanced measurement data (sometimes called ''top-down'' methods) with bottom-up methods in a way that avoids double counting of emissions, including how frequently measurements would need to be conducted to be considered reliable or representative of annual emissions for reporting purposes, and what emissions simulation modeling would be necessary to accurately estimate annual emissions. As described previously in this section, the different types of measurement data have a wide range of detection limits and spatial resolution, which makes converting point estimates to an annual emission estimate as required by and necessary for the purposes of the GHGRP subpart W difficult. Therefore, this final rule does not include a general provision to incorporate the use of advanced measurement approaches for sources at this time and instead specifically allows its use in certain appropriate cases, including for other large release events, due to the limitations described earlier in this section.

The EPA notes that advanced measurement approaches are rapidly evolving, and expects that these approaches will continue to improve over time. Advanced measurement approaches are currently being used to generate a range of valuable information on emissions sources in the oil and natural gas sector and have great promise for playing a greater role in subpart W emissions reporting as experience with using them to quantify emissions grows. We will continue to closely monitor developments in advanced monitoring technologies and measurement approaches and engage with experts and stakeholders on how they can be used in subpart W reporting.

As these measurement approaches continue to develop, the EPA will, as appropriate, undertake notice-and-comment rulemaking to determine under what circumstances these approaches can be used for subpart W reporting of methane emissions, and how subpart W reporters can use these approaches to quantify annual emissions based on advanced technologies and the rapid evolution of such technologies. Given the wide variety of advanced measurement approaches and the methodological challenges described above, the EPA believes it is necessary to provide adequate notice and opportunity for comment on the use of advanced measurement approaches in order to incorporate such technologies into subpart W. We believe that such an approach is consistent with the historic implementation of the Greenhouse Gas Reporting Rule which has been revised over time to incorporate the latest data, updated scientific knowledge and additional measurement methods. In advance of such a rulemaking, the EPA intends to solicit input on the use of advanced measurement data and methods in subpart W through a request for information, workshop or white paper. We further intend to evaluate for potential future subpart W updates whether there are measurement approaches that could be used to estimate annual emissions for any source categories under subpart W or for facility-level emissions, what level of accuracy should be required for such use, and whether the development of standard protocols for estimating emissions from advanced measurement (either by the EPA or third-party organizations) could help inform this determination. We also intend to evaluate whether there are other appropriate uses of this data for the purposes of reporting under subpart W of the GHGRP, including for what types of emission sources and emission events and what specific measurement approaches use may be appropriate, especially in terms of spatial scale and minimum detection limits. We will also continue to evaluate how frequently measurements would need to be conducted to be considered reliable or representative of annual emissions for reporting purposes.

[13] See, *e.g.,* Bell, C., et al. ''Performance of Continuous Emission Monitoring Solutions under a Single-Blind Controlled Testing Protocol.'' *Environ. Sci. Technol.* 2023, 57, 14, 5794–5805. Published March 28, 2023. *https://doi.org/10.1021/acs.est.2c09235.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

C. Revisions to Reporting Requirements To Improve Verification and Transparency of the Data Collected

The EPA is finalizing several revisions to existing reporting requirements to collect data that will improve verification of reported data and improve the transparency of the data collected. Data reported under the GHGRP undergo comprehensive verification review. This process identifies errors that result in the over- or under- statement of emissions that are reported from individual facilities and leads to their correction. As such, amendments that improve the verification process are supportive of the directive under CAA section 136(h) to ensure that reporting under subpart W accurately reflects total methane emissions. Additionally, such revisions will better enable the EPA to obtain data that is of sufficient quality and granularity that it can be used to support a range of future climate change policies and regulations under the CAA, including but not limited to information relevant to carrying out CAA section 136, provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs under the CAA.

The final revisions include changes to the level of reporting of aggregated emissions and activity data that will improve the process of emissions verification and the transparency and granularity of the data. For example, we are finalizing requirements for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segment reporters to report emissions and associated activity data at the site level or well level instead of at the basin level, sub-basin level, or county level.

We are also finalizing additions or revisions to reporting requirements to better characterize the emissions for several emission sources. For example, we are collecting additional information from facilities with liquids unloadings to differentiate between manual and automated unloadings.

Other final revisions to the rule include changes that will better align reporting with the calculation methods in the rule. For example, we are finalizing revisions to 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 current 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 existing 40 CFR 98.236(j)(2)(i)(E) and (F) require reporters to delineate the counts used in equation W–15. The current reporting requirements are inadvertently inconsistent with the language used in the calculation methodology and are seemingly not inclusive of all equipment to be included. Therefore, we are revising 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 finalizing the removal of duplicative reporting elements within or across GHGRP subparts to reduce data inconsistencies and reporting errors. For example, we are eliminating 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 the electronic Greenhouse Gas Reporting Tool (e-GGRT). 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. For Local Distribution Companies (LDCs), both subpart W (under the Natural Gas Distribution segment) and subpart NN 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. The final amendments 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. These data elements are not the throughputs that are proposed to be used for WEC calculations; see section III.U. of this preamble and the 2024 WEC Proposal for more information on those throughputs. This revision will improve the EPA's ability to verify the reported data across subparts.

D. Technical Amendments, Clarifications, and Corrections

We are finalizing other technical amendments, corrections, and clarifications that will 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 changes result from consideration of questions raised by reporters through the GHGRP Help Desk or e-GGRT. In particular, we are finalizing amendments for several source types that will emphasize the original intent of certain rule requirements, such as reported data elements that have been misinterpreted by reporters. In several cases, the misinterpretation of these provisions may have resulted in reporting that is inconsistent with the rule requirements. The final clarifications will increase the likelihood that reporters will submit accurate reports the first time. For example, the EPA is finalizing revisions to the definition of variable ''T_t'' in existing equation W–1 (final equation W–1B) in 40 CFR 98.233 and the corresponding reporting requirements in final 40 CFR 98.236(b)(4)(ii)(D)(4), (b)(5)(i)(C)(2), and (b)(6)(ii) to use the term ''in service (*i.e.,* supplied with natural gas)'' rather than ''operational'' or ''operating.'' This revision emphasizes the EPA's intent that the average number of hours used in equation W–1 (final equation W–1B) 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). These final clarifications and corrections will also reduce the burden associated with reporting, data verification, and EPA review. Additional details of these types of final changes are discussed in section III. of this preamble.

We are also finalizing revisions to applicability provisions for certain industry segments and applicable calculation methods. For example, we are revising the definition of the Onshore Natural Gas Processing industry segment to remove the gas throughput threshold so that the applicable industry segment and calculation methods are defined 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. Therefore, as discussed in greater detail in section III.A.3. of this preamble, we are revising 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.,* NSPS OOOOa). This revision to the Onshore Natural Gas Processing industry segment definition will better define whether a processing plant is 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 will no longer have the potential to change from one year to the next simply based on the facility throughput.

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

Other minor changes being finalized include correction edits to fix typos, minor clarifications such as adding a missing word, harmonizing changes to match other final revisions, reordering of paragraphs so that a larger number of paragraphs need not be renumbered, and others as reflected in the redline regulatory text in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

III. Final Amendments to Part 98 and Summary of Comments and Responses

This section summarizes the specific substantive final amendments for subpart W (as well as subparts A and C), as generally described in section II. of this preamble. Major changes to the final rule as compared to the proposed revisions are identified in this section. The summary of the amendments in each section is followed by a summary of the major comments on those amendments and the EPA's responses to those comments. The document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule,* available in the docket to this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234), contains the full text of all the comments on the 2023 Subpart W Proposal, including the major comments responded to in this preamble. All final amendments, including minor corrections and clarifications, are also reflected in the final redline regulatory text in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

Section III.A of this preamble describes amendments that affect reporting responsibility or applicability. Sections III.B through III.U of this preamble describe technical amendments that affect specific source types or industry segments. Section III.V of this preamble lists miscellaneous technical corrections and clarifications.

A. General and Applicability Amendments

1. Ownership Transfer

a. Summary of Final Amendments

We are finalizing amendments to specific provisions to subpart A that will apply in lieu of existing 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.[14] The final provisions specify which owner or operator is responsible for current and future reporting years' reports following a change in owner or operator for specific industry segments in subpart W, beginning with RY2025 reports. As described in more detail in this section, the provisions vary based upon whether the selling owner or operator will retain any emission sources, the number of purchasing owner(s) or operator(s), and whether the purchasing owner(s) or operator(s) already report to the GHGRP in the same industry segment and basin or state (as applicable). These final revisions are expected to improve data quality as described in section II.C 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.D. of this preamble.

In this final rule, the EPA is not taking final action at this time on the proposed amendments related to responsibility for revisions to annual reports for reporting years prior to owner or operator changes for specific industry segments in subpart W. In consideration of the relationship between revisions to annual reports for prior years and proposed implementation requirements in the 2024 WEC Proposal, the EPA intends to consider those proposed revisions in coordination with the 2024 WEC rulemaking and take action, if finalized, on these requirements at the same time.

As discussed in the 2023 Subpart W proposal, we expect that transactions fall into one of four general categories, and we are finalizing provisions that specify the current and future reporting years' responsibilities for reporting for each of those general categories. First, to address transactions where an 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), we are finalizing as proposed that the facility's certificate of representation must be updated within 90 days of the transaction to reflect the new owner or operator. We are finalizing as proposed the requirement that the purchasing owner or operator will 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 will 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 must include any other applicable emission sources already owned by that purchasing owner or operator in the same geographic area as part of the purchased facility beginning with the reporting year in which the acquisition occurred. We proposed, but are not taking final action at this time on, a requirement that the purchasing owner or operator would also become responsible for responding to EPA questions and making any necessary revisions to annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. As noted above, we intend to consider those proposed revisions in coordination with the 2024 WEC rulemaking and take action on these requirements, if finalized, at the same time.

Second, to address transactions where 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), we are finalizing as proposed that the purchasing owner or operator will merge the acquired facility with their existing facility for purposes of reporting under the GHGRP. In other words, the acquired emission sources will become part of the purchaser's existing facility under the GHGRP and emissions for the combined facility will

[14] Specifically the Onshore Petroleum and Natural Gas Production, Natural Gas Distribution, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline industry segments.

be reported under the e-GGRT identifier for the purchaser's existing facility. We are finalizing as proposed a requirement that the purchaser will 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 will provide the e-GGRT identifier for the merged, or reconstituted, facility. Finally, the purchaser will 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 will be responsible for the report for that entire reporting year) and each reporting year thereafter. We proposed, but are not taking final action at this time on, a requirement that the purchasing owner or operator would also become responsible for responding to EPA questions and making any necessary revisions to annual GHG reports for the purchased facility for reporting years prior to the reporting year in which the acquisition occurred. Similarly, we are not taking final action at this time on a requirement that the acquired facility's certificate of representation be updated within 90 days of the transaction to reflect the new owner or operator. As noted above, we intend to consider those proposed revisions in coordination with the 2024 WEC rulemaking and take action on these requirements, if finalized, at the same time.

Third, to address transactions where 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 finalizing as proposed that the selling owner or operator will 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) will begin reporting as a new facility for the entire reporting year beginning with the reporting year in which the acquisition occurred. The new facility will include the acquired applicable emission sources as well as any previously owned applicable emission sources. We note that, under the provisions that are being finalized as proposed, because the new facility will contain acquired emission sources that were part of a facility that was subject to the requirements of part 98 and already reporting to the GHGRP, the purchasing owner or operator will follow the provisions of 40 CFR 98.2(i) and continue to report unless and until one of the criteria in 40 CFR 98.2(i) are met, instead of comparing the facility's emissions to the reporting threshold in 40 CFR 98.231(a) to determine if they should begin reporting. Each purchasing owner or operator that already reports to the GHGRP in that industry segment (and basin or state, as applicable) will add the acquired applicable emission sources to their existing facility for purposes of reporting under subpart W and will 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, to address transactions where 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 finalizing as proposed that the selling owner or operator for the existing facility will notify the EPA within 90 days of the transaction that all of the facility's emission sources were acquired by multiple purchasers. After consideration of comment, we are revising from proposal use of the term ''current owner or operator'' to instead read ''prior owner or operator'' in the final amendments. The purchasing owners or operators will 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 will 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 the third and fourth types of transactions, we proposed but are not taking final action at this time on a set of provisions to clarify responsibility for annual GHG reports for reporting years prior to the reporting year in which the acquisition occurred. As noted above, we intend to consider those proposed revisions in coordination with the 2024 WEC rulemaking and take action on these requirements, if finalized, at the same time.

We proposed that as part of the third and fourth types of ownership change described previously in this section, the selling owner or operator and each purchasing owner or operator would be required to select by an agreement binding on the owners and operators (following the procedures specified in 40 CFR 98.4(b)) a ''historic reporting representative'' that would be responsible for revisions to annual GHG reports for previous reporting years within 90 days of the transaction. The proposed historic reporting representative for each facility 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. As noted above, we are not taking final action at this time on the proposed provisions for past reporting years after a transaction, including the proposed historic reporting representative provisions, and intend to consider those proposed revisions in coordination with the 2024 WEC rulemaking and take action on these requirements, if finalized, at the same time.

We are finalizing as proposed amendments to 40 CFR 98.2(i)(3), the current provision that allows an owner or operator to discontinue reporting to the GHGRP when all applicable processes and operations cease to operate. Through correspondence with reporters via e-GGRT, we are aware that there have been times that an owner or operator divested a facility and was therefore no longer required to report the emissions from that facility, but even though the facility changed owners and did not cease operating, the selling owner or operator chose the provisions of existing 40 CFR 98.2(i)(3) as the reason they were ceasing to report because none of the other options fit the situation. The EPA's intent is that this reason for no longer reporting to the GHGRP should only be used in cases in which all the applicable sources permanently ceased operation. Therefore, we are finalizing as proposed amendments to clarify that 40 CFR 98.2(i)(3) will not apply when there is a change in the owner or operator for facilities in these four industry segments, unless the changes result in permanent cessation of all applicable processes and operations. We are finalizing a new paragraph at 40 CFR 98.2(i)(7) to specify that a selling owner or operator that completes the fourth transaction type discussed above (*i.e.,* all the emission sources from the reporting facility are sold to multiple owners or operators within the same reporting year) may discontinue reporting for the facility for the reporting years following the year in which the transactions occurred provided that notification is provided to the Administrator. Prior to the addition of this new paragraph, there was not a reason provided in the regulations to discontinue reporting under 40 CFR 98.2(i) that applied to this situation.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to ownership transfers.

Comment: Multiple commenters suggested that the EPA amend the reporting and ownership transfer provisions such that owners and operators would only be responsible for reporting emissions that occurred during their period of ownership or operation and that new owners should not be responsible for methane taxes generated by the prior owner. Commenters identified the WEC as a reason to reconsider reporting responsibilities. Under the structure suggested by commenters, in the case of transfer of a facility during a reporting year there would be a separate report submitted by each owner or operator. One commenter asserted that multiple reports from multiple reporters would be necessary to ensure accurate reporting as required by CAA section 136(h). The commenter further stated the proposed requirements for consolidated reporting by one owner would constitute a deviation from the IRA and increase the possibility of inaccurate reporting. Commenters further stated that new owners or operators should not be responsible for revisions to reports prior to their effective date of acquisition.

Response: The EPA is not taking action in this final rule on the existing subpart W requirement that the owner or operator of a facility as of December 31 is responsible for submitting a report including the entire calendar year's emissions by March 31 of the following calendar year.

The EPA disagrees with the assertion that multiple reports and reporters will be necessary to ensure accurate emissions reporting. The amendments affecting ownership transfers do not impact the existing requirement that the owner or operator of a facility as of December 31 is responsible for submitting a report by March 31 of the following calendar year. The commenter did not identify specific issues with this current structure leading to the inaccurate reporting of emissions data. Rather than ensure accurate reporting as the commenter claimed, the EPA believes that preparation and submission of multiple reports by different entities related to the same emission sources would lead to duplicative burden and raise the potential for inconsistencies in reported data. The EPA therefore believes it would be neither practical nor supportive of the CAA section 136(h) directive to ensure the accuracy of reported data for the reporting responsibility for a single facility to be duplicated in multiple reports among multiple owners and operators. For these same reasons, the EPA disagrees with commenters that this implementation deviates from the IRA.

With respect to the assertion that the existing reporting structure makes the new owner or operator responsible for the methane taxes generated by the prior owner, the EPA notes that the comment concerns the timing of ownership changes and the impact upon WEC obligations and that the EPA considers these to be outside the scope of this subpart W rulemaking and they are addressed in the 2024 WEC Proposal. With respect to the assertion that retaining this reporting structure would constitute ''deviating from the IRA,'' the EPA notes that full calendar year reporting under subpart W was required for the facility as of December 31 at the time of signature of the IRA. The EPA finds no indication in the text of CAA section 136 suggesting that revision to this structure was mandated or intended.

Comment: Multiple commenters opposed the proposed implementation of a historic reporting representative. Some commenters suggested that a historic reporting representative was unnecessary as owners and operators should only be responsible for emissions that occurred during their time of ownership or operation, although one commenter stated that the historic reporting representative was preferable to placing the responsibility for historic reporting on the new owner or operator. Some commenters stated that there is no certainty that a historic reporting representative would have access to the data and information needed to accurately respond to questions regarding prior year reports. One commenter suggested that in place of a historic reporting representative, the EPA implement a data freeze after one year from the original submittal date of a report.

One commenter supported the proposed use of a contractually determined reporting representative but asserted that some transactions may be too complicated to fit within the four categories of transactions that were proposed.

Response: The EPA is not finalizing the proposed requirements related to designation of a historic reporting representation at this time. To better facilitate implementation of the WEC under CAA section 136(c) and alignment with the final WEC rule, the EPA intends to finalize requirements related to the responsibility for historic reporting as part of a future rulemaking.

The EPA acknowledges that commenters expressed concern regarding whether the individual responsible for historic reporting would have access to data and information needed to accurately respond to questions regarding GHG reporting, including potentially confidential or sensitive information and correspondence. Similarly, in past correspondence regarding the GHGRP, facility representatives have expressed concern that providing an individual access to the data and information needed for historic reporting would also provide that individual access to potentially confidential or sensitive information and correspondence submitted to e-GGRT in future year reporting. The EPA notes that the EPA is considering updating e-GGRT to implement these proposed provisions if finalized in a future rulemaking. For example, one potential update could be that the individual that an owner or operator selects to be responsible for historic reporting would be provided access to a facility's reports and correspondence limited to the reporting years for which that owner or operator was responsible for reporting for the facility. This potential implementation would prevent the individual responsible for historic reporting from accessing potentially confidential or sensitive information and correspondence for reporting years following an ownership transaction.

The EPA is not implementing a data freeze for subpart W reporting as part of this final rulemaking. The EPA recognizes that resubmissions for historic reporting years have the potential to be complex due to changes in facility owners or operators, and further, that because assessment of the WEC is based upon subpart W reporting these revisions may carry financial obligations under the WEC program (compared to the GHGRP). In recognition of this potential complexity, in the 2024 WEC Proposal a deadline of November 1 was proposed for resubmission of WEC filings that would otherwise be required due to resubmission of a report under subpart W. While not at issue in this subpart W rulemaking, we note that as part of the 2024 WEC Proposal, we proposed that the EPA would retain the right to reevaluate WEC obligations in WEC filings after November 1 (*e.g.,* as part of an EPA audit of facility data). Similarly, the proposed November 1 deadline would not apply to adjustments to WEC obligations resulting from the process to resolve unverified data, proposed at 40 CFR 99.8, should that resolution occur after November 1. The EPA's proposed approaches for WEC filing requirements and data verification are intended to incentivize complete and accurate WEC filings under part 99, and thus corresponding reporting of complete and accurate data under part 98 to the extent it is relevant for purposes of WEC, by March 31 of each year. The EPA anticipates that there may be situations requiring resubmissions of subpart W reports after the proposed November 1 deadline for purposes of the GHGRP, but notes that these situations would not necessarily require resubmissions or trigger a change in WEC obligation under the proposed WEC rule. The EPA is not taking final action on the requested implementation of a data freeze for subpart W reporting under this final rule and considers the comment insofar as it relates to WEC timeframes under the proposed 40 CFR part 99 to be outside the scope of this subpart W rulemaking.

The EPA acknowledges the existence of complex asset transfers within the oil and gas industry but is not aware of, and the commenter did not provide an example of, a transfer that would not fit within the four categories proposed. The four categories have been finalized as proposed.

Comment: Multiple commenters stated that a new owner or operator should not be responsible for correcting or resubmitting reporters that were submitted and certified prior to their acquisition of a facility.

Response: The EPA is not taking final action on the proposed requirements related to designation of a historic reporting representation at this time. To better facilitate implementation of the WEC under CAA section 136(c) and align with the final WEC rule, the EPA intends to finalize requirements related to the responsibility for historic reporting as part of a future rulemaking.

Comment: One commenter noted that in the proposed 40 CFR 98.4(n)(1) and (2) it is not directly stated which party is responsible for filing the certificate of representation following the transfer of a facility. The commenter suggested clarifying amendment to specify this is the responsibility of the new owner or operator. Another commenter stated it is unclear what is meant by the term certificate of representation.

Response: The EPA is finalizing 40 CFR 98.4(n)(1) and (2) as proposed. The language referenced by the commenter is consistent with the existing language at 40 CFR 98.4(h) related to updates to the certificate of representation following a change in owner or operator in the general case (*i.e.,* for all facilities other than those specified in the final introductory paragraph at 40 CFR 98.4) and is consistent with the EPA's interpretation of that language (that such updates are the responsibility of the new owner or operator). As previously noted, the EPA plans to finalize amendments to historic reporting responsibilities in a future rulemaking. The EPA intends to consider any associated amendments related to the responsibility for updates to the certificate of representation at such time. Regarding the last comment, we note that the contents of a complete certificate of representation are listed at 40 CFR 98.4(i), which is not being amended as part of this rulemaking.

Comment: Multiple commenters addressed the impact of the proposed amendments on reporting and notification requirements for partial facility sales. One commenter opposed the proposed language at 40 CFR 98.4(n)(3) that would require both the existing and purchasing owner and operator to report for their respective emission sources until the criteria in 40 CFR 98.2(i) are met. The commenter requested that the EPA instead finalize a provision allowing the existing and purchasing owners and operators to compare their respective facility emissions to the reporting threshold in 40 CFR 98.231(a).

One commenter expressed general support for the proposed revisions but stated that the proposed language for reporting requirements under the scenarios addressed at 40 CFR 98.4(n)(3) and (4) are ambiguous. The commenter recommended that the EPA clarify that in scenarios of partial facility sales the criteria of 40 CFR 98.2(i) would apply. The commenter further recommended that the EPA finalize a requirement requiring notification when any type of transaction occurs.

Response: The EPA is finalizing as proposed the provisions related to continued reporting obligations following the sale of a portion of a facility's emission sources. The EPA believes the language of 40 CFR 98.4(n)(3) is clear regarding continued reporting obligations for both the existing and the purchasing owner or operator involved in a transaction. 40 CFR 98.4(n)(3) requires that the existing owner or operator continue to report for their retained emission sources unless and until the criteria of 40 CFR 98.2(i) are met. Similarly, 40 CFR 98.4(n)(3)(i) requires that a purchasing owner or operator that does not already have a reporting facility in the same industry segment continue to report for the new facility until one of the criteria in 40 CFR 98.2(i) are met. For a purchasing owner or operator that already has a reporting facility in the same industry segment, 40 CFR 98.4(n)(3)(ii) directs that the acquired emission sources must be included in their annual report. The EPA disagrees that the reporting threshold in 40 CFR 98.231(a) should be used in place of the provisions of 40 CFR 98.2(i) to determine continued reporting obligations. The commenter that expressed general support for the provisions stated that 40 CFR 98.2(i) contemplates continued reporting for operators whose facilities no longer meet the original definition of a applicable facility under subpart A—including after they have sold assets. The final amendments ensure that the applicable requirements to cease reporting for facilities involved in the transactions to which 40 CFR 98.4(n)(3) applies are the same as the applicable requirements to cease reporting for existing facilities.

The EPA did not propose, and is not finalizing, a requirement that notification is provided when any type of transaction occurs. As discussed above, the EPA believes this final rule establishes clear requirements regarding continued reporting for transferred assets. Further, the disaggregated reporting provisions finalized for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are expected to provide the EPA the ability to track the movement of assets without requiring specific notification of each asset transfer.

Comment: One commenter stated that the use of the word ''current'' in the proposed language of 40 CFR 98.4(n)(4) was ambiguous in the context of a transfer of ownership or operation and recommended that the EPA clarify that the new owner or operator should be required to notify the EPA of the acquisition of emission sources.

Response: The EPA acknowledges the potential for confusion with the term ''current owner or operator'' in the proposed 40 CFR 98.4(n)(4) and has instead finalized the term ''prior owner or operator'' in this context. The EPA has not adopted the commenter's suggestion that this requirement should instead be the responsibility of the new owner or operator. The intent of this notification is to inform the EPA that reporting will discontinue for the prior facility due to the sale of all emission sources to multiple purchasers. The EPA does not believe any single purchaser will necessarily know that all of the assets from the prior facility had been sold or the identity of other purchasers.

2. Definition of ''Owner'' and ''Operator''

Consistent with section II.D. of this preamble, the EPA is finalizing the proposal 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. The EPA received only supportive comments on this clarification.

3. Onshore Natural Gas Processing Industry Segment Definition

The EPA is finalizing several amendments to 40 CFR 98.230(a)(3) as described in this section. The EPA received only minor comments on the proposed requirements related to the definition of ''onshore natural gas processing'' in 40 CFR 98.230(a)(3). See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

According to existing 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 carbon dioxide (CO2) from natural gas, provided the annual average throughput at the facility is 25 MMscf per day or greater. The industry segment also currently includes all residue gas compression equipment owned or operated by natural gas processing facilities that is not located within the facility boundaries.

The EPA is finalizing as proposed an amendment to revise the definition of ''onshore natural gas processing'' in 40 CFR 98.230(a)(3) to specify that it includes forced extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both, similar to the definition of ''natural gas processing plant'' in NSPS OOOOa. The revised definition for natural gas processing also does not include the 25 MMscf per day threshold for facilities that separate NGLs from natural gas using forced extraction but do not fractionate NGLs. We are also finalizing the revisions to the term ''forced extraction of natural gas liquids'' in 40 CFR 98.238 as proposed to specify that forced extraction does not include ''a Joule-Thomson valve, a dewpoint depression valve, or an isolated or standalone Joule-Thomson skid.'' These amendments will improve the verification and transparency of the data, particularly across reporting years, consistent with section II.C. of this preamble, and it will provide reporters with certainty about the applicable industry segment for the reporting year, consistent with section II.D. of this preamble, allowing them to focus their efforts on collecting accurate monitoring data and emissions information needed for one applicable industry segment. As explained in the 2023 Subpart W Proposal, while we expect that the final revisions will result in some processing plants that have been reporting as part of onshore petroleum and natural gas gathering and boosting facilities to begin report as onshore natural gas processing facilities, and some onshore natural gas processing facilities beginning to report as part of onshore petroleum and natural gas gathering and boosting facilities, we do not expect that the overall coverage of the GHGRP will decrease.

4. Applicability of Proposed Subpart B to Subpart W Facilities

The EPA is not taking final action on the proposed addition of 40 CFR 98.232(n), which would have referred to subpart B of part 98 (Energy Consumption) that was proposed in the May 22, 2023, GHGRP supplemental proposed rule (88 FR 32852). For the reasons explained in section III.B. of the preamble to the GHGRP amendments that were signed by the EPA Administrator on April 3, 2024,[15] the EPA did not take final action on the proposed addition of subpart B of part 98. Therefore, we are not taking final action on proposed amendments to subpart W to clarify the intent for subpart W reporters to also report under subpart B. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for a complete listing of all comments and responses related to subpart B.

B. Other Large Release Events

1. Summary of Final Amendments

We are finalizing the inclusion of an additional emissions source, referred to as ''other large release events,'' to capture maintenance or abnormal emission events that are not fully accounted for using existing methods in subpart W, consistent with section II.A. of this preamble. We proposed to include calculation and reporting requirements for other large release events in the 2022 Proposed Rule and in the 2023 Subpart W Proposal. We are finalizing the definition of other large release event to include planned releases, such as those associated with maintenance activities, for which there are not emission calculation procedures in subpart W as proposed in the 2023 Subpart W Proposal, except that we are specifically excluding blowdowns for which emissions are calculated according to the provisions in 40 CFR 98.233(i) from the definition of other large release events, for reasons described later in this section. We are also finalizing the language in 40 CFR 98.233(y)(1)(ii), with modifications from proposal for clarity, that instructs the reporter to exclude emissions that would have been calculated for the source(s) of the other large release event during the timespan of the other large release event from source-specific emissions calculated under paragraphs 40 CFR 98.233(a) through (h), (j) through (s), (w), (x), (dd), or (ee), as applicable, to avoid double counting.

One primary difference in the requirements we are finalizing for other large release events and those in the 2023 Subpart W Proposal is we are limiting the threshold for other large release events to include only events under this source category with an instantaneous CH_4 emission rate of 100 kg/hr or higher or events with instantaneous CH_4 emission rates of 100 kg/hr greater than the emissions estimated using other subpart W methods (the latter of which is applicable for events associated with calculation methods elsewhere in subpart W), which aligns with the threshold for events under the Super-Emitter Program in NSPS OOOOb and EG OOOOc, rather than having both an aggregate 250 $mtCO_2e$ threshold and a 100 kg/hr methane instantaneous threshold with reporting required if either threshold was exceeded. We are also finalizing an additional clarifying sentence at 40 CFR 98.233(y)(1) to clearly state that emissions for the entire

[15] A copy of the final preamble and rule is available at *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

duration of the event must be reported as an other large release event, not just those time periods of the event in which emissions exceed the 100 kg/hr instantaneous rate threshold to ensure that the total emissions for the duration of the event are appropriately accounted for in subpart W. This clarification to the proposed provision was added to ensure that the emissions from the entire event are reported; on further review the EPA wants to ensure the requirement to calculate and report emissions from the event could not be misinterpreted, given the use of the 100 kg/hr instantaneous threshold in the final rule, as applying to only those periods when the emissions rate exceeded the 100 kg/hr emission rate threshold. Under the final provisions, we are also clarifying that events that meet or exceed the 100 kg/hr emission rate threshold when simultaneous emissions from multiple release points that have a common root cause are aggregated must be reported as a single other large release event. This approach aligns subpart W's other large release event provisions with the Super-Emitter Program, which uses remote sensing technologies that typically detect and measure the cumulative emissions from the site or facility. Even when more geospatially accurate methods are used, the measurements may still reflect the cumulative emissions from an aggregate plume created by several nearby sources within the site or facility.

We are not finalizing the proposed separately applicable 250 $mtCO_2e$ per event threshold. After consideration of comments and further consideration of available scientific literature, we determined that the single threshold is more straightforward to implement and more consistent with the emission events we sought to include than the 250 $mtCO_2e$ threshold, which could include emission events with relatively small emission rates that occur for prolonged periods of time. Our literature review reveals that tanks, unlit flares, and reciprocating compressors have been the majority of emission sources with emissions that may exceed 250 $mtCO_2e$ over the duration of the emissions event but are generally below 100 kg/hr. We already have calculation methods appropriate for these sources so the vast majority of these lower rate emission events would continue to be reported under the source-specific methods and would not be reported as an other large release event, even if the 250 $mtCO_2e$ threshold was retained. Thus, removing the 250 $mtCO_2e$ threshold should not meaningfully reduce the emissions that would have to be reported under the other large release event provisions.

Additionally, we are changing the requirements related to assessing incremental emission differences from the source-specific methodologies for blowdowns from what was proposed. Specifically, we are excluding blowdowns from the list of subpart W sources for which facilities must assess whether the incremental emissions threshold for an other large release event has been met or exceeded. Blowdowns can often have high, but short-lived, release rates that might otherwise be identified as other large release events; however, we are excluding such events from the other large release event source because our assessment is that the calculation methods for blowdown events under 40 CFR 98.233(i) are more accurate for this emission source, which has highly transient emissions. Specifically, the calculation methodology for blowdown vent stacks under 40 CFR 98.233(i) determines the total volume of between closed isolation valves and uses the pressure of the system at the start and end of the blowdown to calculate the amount of gas released, which we consider to be accurate even for large events. During a blowdown event, the emission rate will be highest at the start of the event (highest pressure) and consistently decline during the blowdown. Many remote measurements only determine the emission rate during a minute or two of observations, so projecting this instantaneous emission rate to estimate event emissions for blowdowns can be highly inaccurate. For these reasons, blowdowns will continue to be reported under blowdown vent stacks and not under other large release events, even for large emission rate events. We note that accidental ruptures of transmission pipelines at onshore natural gas transmission pipeline facilities and gathering pipelines at onshore petroleum and natural gas gathering and boosting facilities are not considered blowdowns if the isolation valves are not closed at the time of the incident because the volume of the gas released is not limited to the volume between the isolation valves that are subsequently closed to isolate the leak for repair. Considering the high pressures at which transmission pipelines operate, we expect these incidents are likely to have emissions exceeding 100 kg/hr and are most accurately assessed under the other large release event provisions.

Consistent with the 2023 Subpart W Proposal, for other large release events, we are finalizing calculation requirements that rely on measurement data, if available, or a combination of engineering estimates, process knowledge, and best available data, when measurement data are not available. The final calculation procedure consists of estimating the amount of gas released and the composition of the released gas. The amount of gas released would generally be calculated based on a measured or estimated emission rate(s) and an event duration. We are finalizing provisions as proposed that the start time of the duration must be determined based on monitored process parameters, when available, such as pressure or temperature, for which sudden changes in the monitored parameter signals the start of the event. If the monitored process parameters cannot identify the start of the event, we are finalizing the requirement that reporters must assume the release started on the date of the most recent monitoring or measurement survey, including advanced technology surveys or voluntary surveys, that confirms the source was not emitting at the rates above the other large release event reporting threshold or assume a start date of 91 days prior to the date of identification, whichever start date is the most recent. We are also finalizing provisions that for the purpose of estimating the total volume of the release during the event, monitoring or measurement survey includes any monitoring or measurement method in 40 CFR 98.234(a) through (d) as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying CH_4 emissions at 100 kg/hr, with a modification from proposal to add language specifying the screening method must be capable of identifying events at this threshold at a 90 percent probability of detection as demonstrated by controlled release tests. This revision in the final provision will ensure that appropriate advanced screening methods are used. We recognize that some release events may be identified using audio, visual, and olfactory (AVO) inspections. Therefore, we are finalizing additional provisions that specify that, when an event is identified using AVO methods, previous AVO inspections are considered monitoring surveys and can be used to limit the start date of an event.

One change from proposal in this final rule is to the default assumptions associated with the start date of an other large release event. If no monitoring data or measurement survey data are available, we are finalizing that reporters must assume that the event start date occurred 91 days (three months) prior to the event identification date. We proposed a 182-day default maximum duration and requested comment on a 91-day default duration. The available data suggest that the duration of emission events exceeding 100 kg/hr is highly variable, commonly lasting several hours to several weeks but occasionally lasting 182 days or longer, as noted by one commenter.[16] After reviewing the available information, we determined that a 91-day default more accurately reflects an average duration than the proposed 182-day default. We note that, consistent with the directives in CAA section 136(h), we provide default durations for other sources in the GHGRP, such as equipment leaks, where leaks identified are assumed to leak all year long (when annual surveys are conducted) or since the previous survey (with the option for reporters to conduct additional surveys). For other large release events, we similarly include several provisions that allow reporters to determine the start date based on their facility's specific data, including consideration of other monitoring conducted by the facility; however, we maintain that, in the absence of other facility-specific information, a default value is needed and that default should be appropriate based on available data of other large release events at this time so as to result in reasonably accurate reporting of total emissions for the facility, as discussed in the preamble of the 2023 Subpart W Proposal and in the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule,* available in the docket to this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234). Based on consideration of the comments received and for reasons discussed in section III.B.2. of this preamble, we are finalizing the default start date of the event, when other information is not available to support a shorter duration, would be 91 days from the time the event was first identified. We are aware that many events may be shorter than 91 days; under the final provisions operators may choose to gather and use other specified information to determine the actual duration, to avoid the potential need to apply a default start date for such events. As new data on event duration becomes available, we intend to evaluate if the default event should be updated in the future through a future rulemaking process. We are revising from proposal the language regarding this 91-day default start date to more clearly specify that it is used to establish the start date of the event. The 91-day default start date prior to the date of detection does not limit the cumulative duration of an event in cases where the repair or cessation of the emissions is delayed after the date of event detection. For example, if an event is immediately identified but takes 120 days to repair, the full duration of the event (120 days) must be used. The 91-day default only applies to the determination of the start date and not the cumulative duration. We are finalizing, as proposed, that the end time of the release event must be the date of the confirmed repair or confirmed cessation of emissions. There may be events that span across two separate reporting years. In such cases, we are finalizing as proposed that the volume of gas released specific to each reporting year would be calculated and reported for that reporting year starting with RY2025.

For explosions or fires where some of the gas may be combusted or partially combusted, we are finalizing that reporters must estimate the portion of the total volume of natural gas released that was combusted in the explosion or fire in order to determine the composition of GHG released to the atmosphere during the event. For the portion of natural gas released via combustion in an explosion or fire, we are finalizing as proposed that a maximum combustion efficiency of 92 percent be assumed. Because these releases are not through engineered nozzles that can be designed to promote mixing and combustion efficiency, the combustion efficiency of these releases can be highly variable and are expected to be less efficient than a flare designed to destroy methane. Since facilities must first estimate the fraction of the gas released via combustion, we expect that the total combustion efficiency, considering all gas released over the length of the event, will be much lower than 92 percent.

We are finalizing requirements for facilities to evaluate releases when there is monitoring or measurement data completed by the EPA or the facility. We are also finalizing requirements for facilities to evaluate releases when there is a notification from the EPA Super-Emitter Program in NSPS OOOO/OOOOa/OOOOb at 40 CFR 60.5371, 60.5371a, 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62. After consideration of comments received, as discussed in section III.B.2. of this preamble, and in alignment with the final provisions of the Super-Emitter Program in NSPS OOOO/OOOOa/OOOOb and EG OOOOc, we are not finalizing the proposed provision that subpart W reporters must consider other third-party information (*i.e.,* information from parties other than the EPA's or facility's sponsored monitoring events or notifications of large potential super-emitter events under the Super-Emitter Program in NSPS OOOO/OOOOa/OOOOb and EG OOOOc received by the facility from the EPA), and are accordingly not finalizing the use of the term ''credible information.'' Other third-party notifications are not assured of having the credibility and defined requirements that notifications from the EPA under the Super-Emitter Program, or data from monitoring or measurement conducted by the EPA or the facility, will have and the EPA has concluded that it is not appropriate to place a potentially large burden on subpart W reporters to respond to such information. The final provisions of the Super-Emitter Program in NSPS OOOO/OOOOa/OOOOb have robust assurances of credibility, reliability and transparency. The entities doing the super-emitter monitoring under NSPS OOOO/OOOOa/OOOOb must have the remote-sensing technology they are using (*e.g.,* satellites) certified by the EPA under the EPA's advanced methane detection technology program, including rigorous accuracy checks, where the EPA is certifying that the technology used is capable of providing accurate and reliable data within the requirements of the Super-Emitter Program. The entity filing the super-emitter report must also be certified by the EPA, to demonstrate that the third party has the training and expertise to interpret the data and identify a super-emitter event and has appropriate and reliable methods for identifying the owner or operator of the sites where the super-emitter event occurred. The third-party reports must be filed with the EPA

[16] Kairos Aerospace comments on the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems. Letter from Ryan Streams, Kairos Aerospace, to Jennifer Bohman and Mark DeFigueiredo, U.S. EPA, September 29, 2023. EPA Docket Id No. EPA–HQ–OAR–2023–0234–0240. ''However, Kairos has also noted instances where emissions that would qualify as ''Other Large Release Events'' do appear to be highly persistent in nature. Kairos analyzed our emission detections during 2022 across the Anadarko, Barnett, DJ, Eagle Ford, Haynesville, Permian, San Joaquin, San Juan, and Uinta Basins and observed 714 upstream sites that had emissions that persisted for at least 182 days. This does not represent a majority of Kairos detections—Kairos observes thousands of emissions per year, the majority of which persist for less than 182 days—but it does appear that long duration events can happen.''

within 15 days of detection, increasing the opportunity for the owners and operators to get timely notice, and must also meet specified reporting criteria and be filed under attestation that the information is true and accurate to the best of the notifier's knowledge. Once the super-emitter report is received by the EPA, the EPA evaluates the report for completeness and accuracy before sending a super-emitter notice to the owner or operator. The super-emitter notices, and the owner or operator's response, will all be posted to a public website. All of these requirements and the significant oversight role the EPA assumes in certifying both the technology and the reporter, as well as the checks performed once the reports are submitted to the EPA, demonstrate that the data underlying the EPA's notices are credible and reliable and thus support the EPA's conclusion that the emissions included in the super-emitter notices from the EPA must be evaluated for a facility's subpart W report. We note that our judgment regarding the revisions to requirements for each type of source within each subpart W industry segments reflects our determinations specific to considerations for each source in each industry segment, including other large release events. More specifically here, the revisions for other large release events are intended to be and are implementable even absent revisions to the other sources, and vice versa, as they each independently ensure that the emissions reported under subpart W for the given source or industry segment at issue are consistent with the directives in CAA section 136(h) and improve the subpart W provisions as described in section II. of this preamble. Furthermore, the other large release event requirements for facilities to evaluate releases when there is monitoring or measurement data completed by the EPA or the facility are intended to be and are implementable even absent the other large release event requirements for facilities to evaluate releases when there is a notification from the EPA Super-Emitter Program in NSPS OOOO/OOOOa/OOOOb at 40 CFR 60.5371, 60.5371a, or 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62. Accordingly, the EPA finds that these other large release event requirements are severable from each other, and that at minimum revisions for each source are severable from revisions to each of the other sources.

Under the Super-Emitter Program, the EPA may receive third-party notifications and in turn notify owners and operators of potential super-emitter events that are related to subpart W facilities, including subpart W facilities that either do or do not have NSPS OOOO/OOOOa/OOOOb or EG OOOOc affected facilities. Under subpart W, we are finalizing that owners and operators are required to report whether emission events identified in those notifications are included in their annual emissions report and if so, under which source category. We are clarifying in the final rule that facilities must include in the facility's annual emissions report emissions events identified in super-emitter notices received from the EPA unless the owners and operators can certify that the facility does not own or operate the equipment at the location identified in the notification or, in situations where there are multiple facilities that own and operate equipment within 50 meters of the location identified in the notification, the owners and operators can certify that their facility does not own or operate the emitting equipment at the location identified in the notification or unless the EPA has determined that the notification contains a demonstrable error. For consideration of demonstrable error, the facility must submit a statement of demonstrable error as specified by 40 CFR 60.5371, 60.5371a, or 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62.[17] We are finalizing additional requirements for actions the owners and operators must complete in order to be able to certify that the facility does not own or operate the emitting equipment at the location identified in the notification in situations where there are multiple facility owners and operators of equipment at the location. Specifically, the facility must complete an investigation of available data as specified in 40 CFR 60.5371b(d)(2)(i) through (iv) within 5 days of receiving the notification to identify the emission source related to the event. If this data investigation does not identify the emission source, the facility must conduct a complete leak survey of equipment within 50 meters of the location identified in the notification using any one of the methods provided in § 98.234(a)(1) through (3) within 15 days of receiving the notification. If the data investigation and the leak survey both fail to identify the source of the event, then the facility owner or operator can certify that they do not own the emitting equipment.

[17] Under the Super-Emitter Program, the owner or operator has 15 days to submit a report, which could include a statement of demonstrable error challenging the notification. Events occurring during a calendar year are not reported to the GHGRP until the following March. We also note that facilities have the ability to revise their annual reports after submission if errors are identified.

Further, we are finalizing as proposed definitions of 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.

Finally, we are finalizing a series of reporting requirements in 40 CFR 98.236(y) related to the type, location, duration, calculations, and emissions of each ''other large release event'' similar to those proposed. Specifically, we are finalizing as proposed that reporters provide the location, a description of the release (from a specified list that includes an ''other (specify)'' option for releases that are not otherwise described well with the list provided), a description of the technology or method used to identify the release, volume of gas released, volume fractions of CO_2 and CH_4 in the gas released, and CO_2 and CH_4 emissions for each ''other large release event.'' We are also finalizing that reporters would provide the start date and time of the release, duration of the release, and the method used to determine the start date and time (options would include a pressure monitor, a temperature monitor, other monitored process parameter, most recent monitoring or measurement survey showing no large release (and specify the type of monitoring or survey), or the default assumption that the release started 91 days prior to the event identification date). As previously explained in this section, the 91 days start date would be the required assumption if the facility does not have empirical data, such as monitored process parameter data or leak inspections or advanced technology monitoring or measurement surveys, to identify the release start date, a reduction from the 180 days proposed. These provisions are otherwise being finalized as proposed except for minor revisions to reflect the revisions and clarifications pertaining to the default assumption start date. We are also finalizing as proposed that reporters provide a general description of the event and indicate whether the ''other large release event'' was also identified as a potential super-emitter event under the super-emitter event provisions of NSPS OOOO/OOOOa/OOOOb at 40 CFR 60.5371, 60.5371a, or 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62.

We are finalizing that reporters that received super-emitter event notifications from the EPA would be required to report certain information on each release notification with some revisions from proposal. We are adding language to limit reporting requirements for super-emitter event notifications to those for which the EPA does not determine that the notification contains a demonstratable error. For consideration of demonstrable error by the EPA, facilities must describe the demonstrable error in their Super-Emitter Program report according to the provisions of NSPS OOOO/OOOOa/OOOOb at 40 CFR 60.5371, 60.5371a, or 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62. We are finalizing that for each EPA notification received via the Super-Emitter Program (for which the EPA does not subsequently determine that the notification contains a demonstrable error), facilities would report the type of event resulting in the emissions as one of the following types of events: normal operations, a planned maintenance event, leaking equipment, malfunctioning equipment or device, or undetermined cause. Because all Super-Emitter Program notifications will come from the EPA, we are not finalizing certain proposed reporting requirements regarding the notification since the EPA will already have this information (*e.g.,* name of notifier, method used, date of measurement, and emission rate and uncertainty bounds). We are finalizing that facilities must indicate whether the emissions identified from the event are included as an other large release event, as another source required to be reported under subpart W, or not included. The only exception to the requirement to include emissions identified via the notification in emissions reported by the facility under subpart W is if the facility is able to make a determination, and then certify to the EPA that the facility does not own or operate the equipment at the location identified in the Super-Emitter Program notification. We are not finalizing the proposed requirement that the reporter provide a reason for not including the emissions from the event in their annual emissions report, as all emission events identified under the Super-Emitter Program that are the subject of a notice from the EPA to the owner/operator must be quantified unless the exception applies and the owner or operator of the facility certifies that the exception applies. This information would support EPA verification and ensure accuracy of the emissions reported under other large release events and the facility's total reported emissions.

We are not finalizing several of the proposed reporting requirements under subpart W regarding notifications under the Super-Emitter Program because all of the Super-Emitter Program notifications will be issued by the EPA and the EPA will already have records of the information we had proposed to require be submitted under subpart W. Specifically, we are not finalizing requirements proposed at 40 CFR 98.236(y)(11)(ii) to report the latitude and longitude of the release as reported in the notification. Also, we are not finalizing requirements proposed at 40 CFR 98.236(y)(11)(iv) to report whether the release was received under the super-emitter event provisions of NSPS OOOO/OOOOa/OOOOb at 40 CFR 60.5371, 60.5371a, or 60.5371b or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 or another notifier, and, if the notification was from another notifier, the reporter would provide the name of the notifier, the remote sensing method used, the date and time of the measurement, the measured emission rate, and uncertainty bounds on the emission rate. These changes from proposal align with the final requirements in the Super-Emitter Program under NSPS OOOO/OOOOa/OOOOb and EG OOOOc and ensure we are not finalizing duplicative reporting requirements.

Finally, we are adding a reporting requirement to provide an indication if you received a super-emitter release notification from the EPA after December 31 of the reporting year for which investigations are on-going such that the annual report that has been submitted may be revised and resubmitted pending the outcome of the super-emitter investigation. This reporting element is provided in recognition of the fact that some super-emitter notifications received in 2026 may impact the 2025 reporting year annual report and there may not be sufficient time to revise the 2025 annual report prior to the March 31 deadline. This reporting element allows the reports to be certified as accurate for submission while noting the potential need for revision depending on the outcome of the super-emitter release notification investigation.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add the other large release events source category.

Comment: We received numerous comments on the proposed thresholds for defining a reportable other larger release event. Several commenters supported both of the thresholds included in the 2023 Subpart W Proposal and some commenters recommended smaller reporting thresholds, specifically reducing the 100 kg/hr to 14 kg/hr. However, a majority of the comments received opposed one or both of the thresholds. Commenters opposing the 250 $mtCO_2e$ threshold generally considered it to be too small, especially considering the proposed 182-day default start date. One commenter stated ''. . . it would take approximately 90 days for a 4.7 kg/hr CH_4 leak to exceed the proposed 250 $mtCO_2e$ threshold. . . A 'large release event' should be just that, not a small release over a long period of time.'' Many of these commenters suggested that the EPA adopt the Pipeline and Hazardous Materials Safety Administration (PHMSA) threshold for a reportable incident of 3 MMscf (approximately 6 times higher that the proposed threshold).

Regarding the 100 kg/hr threshold, a few commenters suggested this emission rate was too high and that a lower threshold should be adopted but most of the commenters recommended that a time component was needed with this threshold because in their view high rate, short duration events would still have small contributions to a facility's annual emissions. Many of the commenters making this argument specifically cited blowdowns as sources with high release rates and short durations and indicated that these types of events should not be considered under the other large release event provisions.

Several of the commenters indicated that the EPA should use a combined threshold (exceed 250 $mtCO_2e$ AND 100 kg/hr methane) rather than the two independent thresholds proposed (exceed 250 $mtCO_2e$ OR 100 kg/hr methane). These commenters noted that this would address issues with low rate, long duration events being considered as other large release events as well as setting a minimum emission quantity for high release events, so short duration, high rate releases such as blowdowns would not be considered under the other large release event provisions. A few of the commenters suggesting a combined threshold also suggested increasing thresholds levels.

Response: After considering comments received, we are finalizing the 100 kg/hr threshold as proposed, but we are not finalizing the proposed 250 $mtCO_2e$ threshold. We determined that the single threshold will be more straightforward for operators to implement, aligns more directly with the EPA's Super-Emitter Program, and is more consistent with the emission events we sought to include in the other large release events source than the 250 $mtCO_2e$ limit. Furthermore, based on our literature review of emission sources with emissions below 100 kg/hr, tanks, unlit flares, and reciprocating compressors were the majority of these smaller rate emitters. In this final rule, we have calculation methods appropriate for these sources that accurately estimate emissions from events with emission rates less than 100 kg/hr and determined that removing the 250 $mtCO_2e$ threshold would not significantly reduce the emissions that would have to be reported under the other large release event provisions because these sources would always be reported under the source-specific reporting requirements, as amended, rather than under other large release event provisions.

We disagree with commenters requesting a smaller 14 kg/hr methane emission rate threshold. First, this emission rate is at or below the level of detection for several remote sensing methods. Second, this would cause a disconnect between the final other large release event threshold and the NSPS Super-Emitter Program requirements.

Regarding commenters suggesting that the 100 kg/hr threshold alone is not appropriate because high rate, short events may have low cumulative emissions and commenters suggestion that the EPA implement one combined threshold exceeding both the 100 kg/hr and the 250 $mtCO_2e$ limit, we disagree that these high emission rate events should not be reported when they are from sources not otherwise subject to reporting under subpart W or from sources for which the source-specific method significantly understates the emissions. We also disagree that the 250 $mtCO_2e$ threshold should be applied to limit the number of releases exceeding 100 kg/hr that should be accounted for within the subpart W other large release event reporting requirements. CAA section 136(h) directed the EPA to revise subpart W to accurately reflect total methane (and waste emissions). Combining the thresholds would cause a disconnect between the Super-Emitter Program and the GHGRP reporting requirements where some NSPS OOOOb or EG OOOOc super-emitter events would not be reported under the subpart W and result in the underreporting of methane emissions to subpart W. Several of the commenters provided hypothetical calculations of mass emissions that would occur for events right at the 100 kg/hr rate for 1 to 5 minutes but offer no data to support that such events are prevalent. We also note that remote detection of high release events relies on an adequate pathlength concentration being present, which would not be the case for these hypothetical short duration events. These methods generally make flux calculations using wind speeds and/or dispersion models that typically assume a developed plume, but the plume would not be fully developed for these hypothetical short events. Even if the emission event can be detected and quantified by the monitoring technique used, it is highly unlikely that the remote monitoring measurement would occur precisely at the time of the 1- to 5-minute release. As such, we find the commenter's concern regarding the need to evaluate numerous very short events is largely unfounded. Nonetheless, we did evaluate potential release events that may be of short duration, as described in the following paragraph.

When commenters provided an example of high-rate, short events, they all pointed to blowdown events. However, blowdowns have their own calculation method, which we consider to be accurate across the duration of the event. Specifically, the blowdown methodology determines the total volume of natural gas between closed isolation valves and uses the pressure of the system at the start and end of the blowdown to calculate the amount of gas released. During the blowdown event, the emission rate will be highest at the start of the event (highest pressure) and consistently decline during the blowdown. Many remote measurements only determine the emission rate during a minute or two of observations. Projecting this instantaneous emission rate to estimate event emissions for blowdowns can be highly inaccurate. Therefore, in the final provisions we have removed the proposed cross-reference to 40 CFR 98.233(i) for blowdowns in the definition of other large release events so no additional calculations are necessary for the emissions from blowdown activities. If a facility fails to close an isolation valve and an intended blowdown event is actually a continuous venting event, such an event is not a blowdown and would have to be reported as an other large release event if it exceeds the 100 kg/hr threshold.

Besides blowdowns, the other likely high rate, short duration release event is pressure relief device (PRD) openings. Currently, PRDs are included under equipment leaks to account for periods when there is a leak past the PRD valve while it is in the closed position, but pressure relief events (periods when the valve intentionally opens due to an over-pressuring of the process vessel or equipment) are not accounted for under most circumstances. For uncontrolled production storage tanks, the calculation method assumes all dissolved methane in fluids from the separator are emitted from the tank. For controlled tanks, we require facilities to assume a zero percent capture/control efficiency over the time period the thief hatch is open (which commonly works as a PRD for the storage tank). Because large, direct PRD releases are not captured elsewhere in subpart W except for storage tanks, we maintain that these emissions must remain reportable as other large release events when the applicable threshold is met to accurately reflect methane emissions from the facility. We note that CAA section 136(h) requires that the EPA revise the requirements of subpart W to accurately reflect the total methane emissions from applicable facilities.

We expect that most short duration events will be adequately captured under source-specific provisions of subpart W, as included in the final rule. Additionally, with the 100 kg/hr emission rate threshold and exclusion of blowdowns, we expect that there will be a limited number of events that qualify under the provisions of other large release events. However, we maintain that the emissions from large emission rate events that are currently not required to be reported or that are not well-characterized under other provisions of subpart W must be reported as other large release events as directed under CAA section 136(h).

Comment: Numerous commenters opposed the proposed requirement that ''. . . if you have credible information that demonstrates the release meets or exceeds one of the thresholds or credible information that the release may reasonably be anticipated to meet or exceed (or to have met or exceeded) one of the thresholds in paragraph (y)(1) of this section, then you must calculate the event emissions and, if the thresholds are confirmed to be exceeded, report the emissions as an other large release event.'' Some commenters expressed concern that this requirement would create a disincentive to voluntary, site-wide monitoring. The commenters also stated that ''credible information'' is poorly defined. Additionally, commenters opposed the proposed reporting requirements that reporters must consider and report on ''third-party notifications'' because unqualified third-party notifications could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The commenters also challenged the legality of this requirement. According to the commenters, CAA section 114 authorizes the EPA only to collect information and it does not authorize the EPA to impose a mandatory reporting obligation that would be triggered by third-party observations or assertions. The commenters also state that any third-party data should be thoroughly vetted by the EPA and should require assessment of persistence of the observed emissions rather than relying on a single observation. One commenter expressed concern that without a robust structure in place, third party notices could be received on March 30 that require revisions to annual reports due on March 31, which the commenter considered unreasonable. Other commenters stated that the EPA must define ''credible evidence,'' allow operators to account for telemetry malfunctions, and remove requirements for reporters to respond to third-party notifications.

Response: We agree with commenters that the EPA should have a role in authorizing third-party measurement systems and collecting and submitting notifications that trigger a reporting obligation under subpart W. Under the Super-Emitter Program, third parties must be EPA-certified entities, who must use EPA-approved remote sensing technologies and approaches. Under the Super-Emitter Program, the EPA will play an important oversight role, including notifying owners and operators after reviewing third-party notifications of events received under the Super-Emitter Program. It is within our authority for this subpart W rule to require reporters to assess the information that we have vetted and sent to them as notifications through the Super-Emitter Program, as it is data that we will have assessed as robust as part of that program, is based on empirical data, and is relevant to accurate calculations of emissions for the facility. Owners and operators identified through the Super-Emitter Program will also investigate and report all sources that they suspect may have caused or contributed to the super-emitter event specified in the EPA notice that they have received. Regarding our authority for the NSPS Super-Emitter Program itself, that is outside the scope of this rulemaking; please see the discussion of our authority in the NSPS OOOOb final rule (see 89 FR 16876–16879, March 8, 2024).

In this final rule, we are not finalizing the proposed term ''credible information'' and simply describing in 40 CFR 98.233(y) the types of information that must be considered. Specifically, we are requiring that facilities consider both EPA-verified notifications provided under the Super-Emitter Program in NSPS OOOOb or federal or state plans consistent with EG OOOOc and any EPA- or facility-funded monitoring data that identify high emission events. Facility owners and operators are required to assess whether those emission events meet the definition of other large release event or are adequately reported under other provisions of subpart W. Owners or operators are not required to consider any other third-party monitoring data besides those received through a notification from the EPA or funded by EPA or the facility, but may consider other third-party data at their discretion. This eliminates the concerns noted by the commenters regarding unvetted and unsolicited third-party notifications.

If a company-sponsored monitoring event (whether voluntary or regulatorily required) indicates an other large release event and site operation staff confirm the release, such emissions should be reported, particularly given the direction under CAA section 136(h). Commenters raised concerns that this may discourage facilities from conducting voluntary site-wide monitoring; however, we consider that the structure of directives Congress gave the EPA under CAA section 136(h), which the EPA acted consistent with in this final rule, provides an incentive for routine monitoring. Routine or continuous monitoring allows a facility to both reduce waste emissions and identify an accurate number and duration of other large emission events. The EPA recognizes that the option for reporters to submit additional empirical data for a given facility may lead to reporters taking additional voluntary actions for subpart W reporting, including for the purpose of demonstrating the extent to which a charge under CAA section 136(c) is owed. To the extent this approach ''incentivizes'' additional actions by the reporter, the EPA considers this to be inherent in the directives Congress gave the EPA in CAA section 136(h). The EPA considers this approach consistent with the directives Congress specified in CAA section 136(h), as it ensures that reporting is based on empirical data and accurately reflects total methane emissions while also allowing reporters to submit appropriate empirical emissions data. We also note that facilities must still act on EPA-provided notifications (from the Super-Emitter Program) about large release events.

With respect to concerns about notifications impacting soon to be submitted or previously submitted annual reports, we first note that the 15-day maximum timeframe for third-party notifiers to submit information to the EPA under the Super-Emitter Program will ensure facilities will be notified of super-emitter events in a timely manner. For events for which start times can be determined, which we expect to be most events, notifications received in late March are unlikely to require revisions of the annual report due at the end of March because it is likely that the facility is already aware of the event from data regularly monitored by the facility. Second, with the revised default start date being 91 days from event identification rather than 182 days, it is much less likely that notifications received at the end of March 2026, for example, would impact the emission totals for the 2025 reporting year, which ends 89 days before the report due date. However, we acknowledge that there may be circumstances that notifications are received near the March 31 due date and there would not be time to evaluate the notification prior to the reporting deadline. In this circumstance, facilities should submit their report to the best of their knowledge. We added a reporting element at 40 CFR 98.236(y)(11)(v) for reporters to provide an indication of whether they have received a super-emitter release notification after December 31 of the reporting year for which an investigation is on-going and might result in the need to revise and resubmit the annual report pending the outcome of the super-emitter investigation. If upon determining the start date and duration of the event, the some of the event's emissions are reportable for the report already submitted, facilities are able to amend the previously submitted annual report to include the applicable event emissions and resubmit that annual report. We note that facilities have 45 days under 40 CFR 98.3(h)(1) to resubmit and correct their annual report after identifying a substantive error, which would afford them additional time to evaluate the event.

While persistence is not specifically included in the Super-Emitter Program notification requirements, many of the remote sensing technologies use multiple determinations (*e.g.,* multiple transects at different heights) to meet required accuracy assessments. [18] [19] For

[18] Karion, A., *et al.,* ''Aircraft-Based Estimate of Total Methane Emissions from the Barnett Shale Region.'' *Environ. Sci. Technol.* 2015, 49, 8124–8131. *https://pubs.acs.org/doi/10.1021/acs.est.5b00217.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

a super-emitter notification that the EPA determines is complete and does not contain information that the EPA finds to be inaccurate to a reasonable degree of certainty, we maintain that it is reasonable to require facilities to report these emissions, even when they may be short-lived. Because some remote measurements may identify an aggregate emission rate from the site or facility that exceeds 100 kg/hr but would not have the spatial resolution to identify the specific source or sources, reporters will need to investigate and identify the source of the emissions. We note that in certain situations, such as a process unit over-pressuring, there may be multiple release points (such as several different PRDs opening at the same time). For these types of releases, we find it reasonable to aggregate the emissions from all release points that have a common root-cause and consider that a single ''event'' because this would more closely tie reported emissions to the available monitoring data.

Comment: Several commenters supported the 182-day default duration. One commenter noted that they had observed 714 upstream sites that (1) had emissions that would qualify as an other large release event under the subpart W proposal, and (2) persisted for at least 182 days. While the majority of the site-level emission detected by the commenter persisted for less than 182 days, the commenter noted that long duration events can occur. On the other hand, numerous commenters opposed the 182-day default duration. These commenters argued that the 182-day duration would effectively require facilities to do more frequent monitoring to avoid having to use the 182-day default duration. Several of these commenters indicated that the 91-day default duration that the EPA requested comment on was more appropriate. Other commenters suggested a default duration of 30 or 45 days may be more appropriate given the typical duration of large release events. Other commenters recommended that reporters be permitted to use a wide variety of methods, including audio, visual and olfactory methods, optical gas imaging (OGI) surveys, flyovers, process parameters, and Supervisory Control and Data Acquisition (SCADA) systems, to determine the start and end time of such events. Some commenters suggested process knowledge and engineering estimates be allowed to determine event duration.

Response: After reviewing comments, we have decided to finalize the default start date of an event to be 91 days prior to event identification rather than the proposed 182 days. While we also inadvertently referred to this as a default duration in our 2023 Subpart W Proposal, we intended this to be the default start date (in the absence of any monitored process data, survey or remote sensing data suggesting a more recent start date). As further indication of our intent, we note that the paragraph at 40 CFR 98.233(y)(2)(ii) is specific to determining the start date of the event and a separate paragraph—40 CFR 98.233(y)(2)(iii)—provides the provision for the end time. Nonetheless, based on comments received, it appears some commenters may have interpreted this to be a maximum event duration; therefore, we are clarifying in the final provisions in 40 CFR 98.233(y)(2)(ii) that, in the absence of monitored process parameter data indicating the start date, the event must be assumed to start on the date of the most recent monitoring or measurement survey that confirms the source was not emitting at or above the rates specified in 40 CFR 98.233(y)(1) or assumed to have started 91 days prior to the date the event was first identified, whichever start date is most recent. Therefore, we are limiting how far back in time the default start date is from the date the event was first identified, but we are not limiting the maximum duration of the event. For example, the Aliso Canyon event was identified soon after it started since the natural gas contained odorant, but the leak took months to repair and had a total duration of about 112 days. In a case with these facts under the final provisions, the duration of the event must still be reported as 112 days based on the identified start date and the confirmed repair date of the leak.

The literature study data we reviewed, as detailed in the subpart W TSD for the final rule (included in Docket ID. No. EPA–HQ–OAR–2023–0234), suggest that the duration of emission events exceeding 100 kg/hr is typically short and that a 91-day default more accurately reflects the typical range of observed durations expected to be reported under this source category than the proposed 182-day default. For example, well blowouts, which is a source of emissions that will be reported under other large release events, often persist for an extended period of time. We disagree with commenters that the default duration should be reduced further, for example to 30 days, because this could in many cases result in under-reporting, and will also disincentivize facilities from trying to pinpoint actual start dates for events that may have started 30 or more days prior to event detection. We also expect that most short duration events will be adequately captured under source-specific provisions of subpart W, as included in the final rule. We also note that, as discussed above, blowdowns, the often-cited example of high-rate, short events, have been excluded from the final provisions for assessment as an other large release events and are required to be reported under the provisions at 40 CFR 98.233(i) for blowdown vent stacks. We also have strong evidence that longer duration events do occur, as noted by one commenter. With the clarification that this default relates only to the start date of the event, we maintain that emissions from longer duration events will still be accurately characterized when using this 91-day default event start date because this default does not limit the total duration of the event in cases where it may take days to several months or longer to correct the issue. While we revised from proposal the default start date, we still expect that this default start date provisions will not be used often and that most facilities will be able to identify a start time based on monitored process parameter data or routine monitoring surveys.

We intentionally provided flexibility for using monitored process parameters for determining the start time of a release in the proposed rule without trying to limit the types of parameters that could be monitored to identify the start date of an event. We note that data from SCADA systems are considered monitored process parameters. If a facility has a continuous monitoring network, they can also use that data to identify the start time. If a facility conducts frequent advanced technology or remote sensing surveys, these can be used to more directly assign a start date, provided that the advanced screening method is capable of identifying events with CH4 emission rates of 100 kg/hr at a 90 percent probability of detection as demonstrated by controlled release tests. We allow process knowledge and engineering estimates in the review of the process data to identify the event start date. However, we maintain that monitored parameters must be used to make these assessments. The comments received could be construed to suggest the facility should be able to pick a start date in the absence of monitored process parameters. This is inconsistent with our intent when allowing process knowledge or engineering estimates for

[19] Schwietzke, S., *et al.,* ''Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements.'' *Environ. Sci. Technol.* 2017, 51, 7286–7294. *https://pubs.acs.org/doi/10.1021/acs.est.7b01810.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

other reporting elements. To ensure clarity on the use of process knowledge or engineering estimates, we are retaining the proposed language that the start time must be determined based on monitored process parameters and adding that ''sound engineering principles'' are to be used to determine the start time based on the monitored process parameter.

We note that most of the monitoring methods suggested by commenters to identify the start date were already proposed at 40 CFR 98.233(y)(2)(iv). At proposal, we did not include AVO monitoring in the list of monitoring inspections provided in 40 CFR 98.233(y)(2)(iv) because the ability of AVO to identify a large event is highly dependent on the height, location, and characteristics of the release. However, we also recognize that on-site AVO inspections may identify some other large release events. If the event is identified via AVO methods, then we think that it logically follows that it is reasonable to allow the use of previous AVO inspections conducted for that equipment to limit the default assumed start date that would otherwise apply (if no monitoring process parameter data or other monitoring or measurement survey is available). Therefore, we are adding an additional sentence to final 40 CFR 98.233(y)(2)(iv) that states that AVO inspections are considered monitoring surveys if and only if the event was identified via an AVO inspection.

Reporters are allowed under the final rule and may prefer to undertake more frequent surveys and submit empirical emissions data because such an approach could shorten the estimated duration of the event. The EPA recognizes that the option for reporters to submit additional empirical data for a given facility may lead to reporters taking additional voluntary actions for subpart W reporting, including for the purpose of demonstrating the extent to which a charge under CAA section 136(c) is owed. As previously explained in response to comment earlier in this section, to the extent this approach ''incentivizes'' additional actions by the reporter, the EPA considers this to be inherent in the directives Congress gave the EPA in CAA section 136(h). The EPA also notes that, as discussed in Section I.E of this preamble, Congress also provided other provisions under CAA section 136, outside the scope of this rulemaking, that were intended to be and may provide incentives; for example, CAA section 136 provides $1.55 billion in incentives for various specified purposes related to CH4 mitigation and monitoring, including through grants, rebates, contracts, loans, and other activities.

Comment: One commenter supported the proposed reporting requirements for other large release events and supported provisions ensuring that reporters can only exclude from reported emissions those coming from third-party notifiers when the reporter provides valid, well-documented reasons for doing so. To do this, according to the commenter, the reporter should be required to submit evidence of a site survey occurring shortly after the notification proving that the event did not occur or come from their site, including time-stamped parametric data from the site showing that normal operating conditions existed. If there is imagery that clearly shows an event at the reporter's site with a quantified, time-stamped emission rate, it should not be rebuttable by the reporter according to this commenter. Several commenters stated that the EPA's proposed reporting requirements for other large release events are nearly identical to the proposed super-emitter response program reporting requirements in NSPS OOOOb and EG OOOOc. According to these commenters, reporting elements such as the unique notification identification number under the Super-Emitter Program, latitude/longitude of release, a description of the technology or method used to identify the release, and the total number of super-emitter release notifications received from a third-party for the facility have no bearing or impact on the reporting of GHG emissions. According to these commenters, GHGRP reporters should not have to bear the burden of retransmitting that information through a separate reporting program as it is already being provided to the EPA through the NSPS program.

Response: As noted previously in this section, we are limiting from proposal the responsibilities of facilities to respond to third-party notifications, but we are finalizing many of the proposed reporting requirements in 40 CFR 98.236(y)(11) for other large release event reporting pertaining to Super-Emitter Program (under the final NSPS OOOOb and EG OOOOc) notifications that come from the EPA. We are finalizing reporting requirements under subpart W for reporters to indicate the results of any assessment or investigation triggered by the notification, including the type of event and whether the identified emissions are included in the subpart W report for a specific source type or as an other large release event. We are clarifying in the final rule that facilities must quantify and include in the facility's annual emissions report emissions events identified in Super-Emitter Program notices received from the EPA (and the EPA has not determined that the notification contains a demonstrable error) unless the owners and operators can certify that the facility does not own or operate the equipment at the location identified in the notification or, in situations where there are multiple facilities that own and operate equipment at the location identified in the notification, the owners and operators can certify that their facility does not own or operate the emitting equipment at the location identified in the notification if they complete certain actions. We are finalizing additional requirements at 40 CFR 98.233(y)(6) for the actions required by the owners and operators in order for to certify that their facility does not own or operate the emitting equipment in cases where there are multiple oil and gas facilities within 50 meters of the location identified in the notification. Specifically, owners and operators must conduct investigations of available data as specified in 40 CFR 60.5371b(d)(2)(i) through (iv) to identify the emissions source related to the event notification within 5 days of receiving the notification. If these investigations do not identify the emissions source, owners and operators must conduct a complete leak survey of their equipment within 50 meters of the location identified in the notification using any one of methods provided in 40 CFR 98.234(a)(1) through (3) within 15 days of receiving the notification. If that survey also fails to identify the emissions source, the facility may certify that they took these required actions and that they do not own or operate the emitting equipment at the location identified in the notification. Note that, if the reporter owns and operates the equipment at the location identified in the notification and there are no other owners or operators of equipment at the location identified in the notification, then that reporter must account for the emissions from that event within their subpart W report. With respect to reporting requirements, if the emissions are not included in the subpart W report, we are finalizing a reporting requirement that the facility must have determined, and then must certify, that the emissions identified in the notification were not from assets under common ownership or control of the facility. In this manner, we are requiring that the emissions from all notifications be accounted for within the subpart W report unless the facility can demonstrate that it does not own or operate the equipment or, if applicable, the emitting equipment at the location identified in the notice from the EPA.

As previously noted in this section, we are also finalizing that only for each EPA notification received via the Super-Emitter Program for which the EPA has not determined that the notification contains a demonstratable error, the facility would be required to report information related to the notification. We note, however, that because the EPA will have vetted and sent to the notifications through the Super-Emitter Program, we expect that demonstrable errors will be rare.

Because all Super-Emitter Program notifications will be coming from the EPA for the subpart W other large release event reporting requirements, we have reduced the reporting requirements under 40 CFR 98.236(y)(11) to focus on those details that the EPA would not already have regarding the super-emitter event. Specifically, we are eliminating from the final rule proposed reporting requirements for latitude and longitude in the notification [at 40 CFR 98.236(y)(11)(ii)] and information on the notifier and method used to detect emissions by the notifier [at 40 CFR 98.236(y)(11)(iv)]. We maintain that the remaining reporting elements are important for understanding which releases are reported as other large release events and which are reported under other provisions of subpart W.

C. New and Additional Emission Sources

Sources of emissions that are required to be reported to subpart W are listed in 40 CFR 98.232 for each industry segment, with the methodology and reporting requirements for each source provided in 40 CFR 98.233 and 98.236, respectively. The EPA is finalizing as proposed the addition of several emission sources that are anticipated to have a meaningful impact on reported emissions, are commonplace in the oil and gas industry, and/or have existing emission calculation methodologies and reporting provisions in the current subpart W regulatory text. For some of these emission sources, discussed in additional detail in section III.C.1. of this preamble, reporting is currently required for some, but not all, industry segments in which they exist. Other emission sources, discussed in additional detail in sections III.C.2 through 5 of this preamble, are not currently required to be reported for any industry segments in which they exist. The addition of sources to subpart W is expected to enhance the overall quality of the data collected under the GHGRP and improve the accuracy of total emissions reported from facilities, consistent with section II.A. of this preamble.

The following sections detail the final additions of emission sources to subpart W.

1. Current Subpart W Emission Sources Proposed for Additional Industry Segments

a. Summary of Final Amendments

Upon review of the U.S. GHG Inventory and the 2021 API Compendium, as well as other publications,[20] the EPA determined that several of the emission sources included in at least one industry segment in subpart W are not currently required to be reported by facilities in all the industry segments in which those sources exist. As such, consistent with section II.A. of this preamble, we are finalizing as proposed the addition of requirements to report CO_2, CH_4, and nitrous oxide (N_2O) emissions (as applicable for the source type) from the following sources under 40 CFR 98.232 and 98.236(a):[21]

- Onshore petroleum and natural gas production: Blowdown vent stacks.
- Onshore natural gas processing: Natural gas pneumatic device venting, Hydrocarbon liquids and produced water storage tank emissions.
- Onshore natural gas transmission compression: Dehydrator vents.
- Underground natural gas storage: Dehydrator vents, Blowdown vent stacks, Condensate storage tanks.
- LNG storage: Blowdown vent stacks, Acid gas removal unit vents.
- LNG import and export equipment: Acid gas removal unit vents.
- Natural gas distribution: Natural gas pneumatic device venting, Blowdown vent stacks.
- Onshore natural gas transmission pipeline: Equipment leaks at transmission company interconnect metering-regulating stations, Equipment leaks at farm tap and/or direct sale metering-regulating stations, Transmission pipeline equipment leaks.

We are also finalizing several revisions that would facilitate implementation of the final provisions that require reporting of these emission sources from additional industry segments. We are finalizing revisions as proposed to change the name of the emission source type ''onshore production and onshore petroleum and natural gas gathering and boosting storage tanks'' to ''hydrocarbon liquids and produced water storage tanks'' and change ''storage tank vented emissions'' to ''hydrocarbon liquids and produced water storage tank emissions'' throughout subpart W. Additionally, we are finalizing revisions as proposed to the emission source type name in 40 CFR 98.233(k) and 98.236(k) from ''transmission storage tanks'' to ''condensate storage tanks.''[22]

We are also finalizing revisions to the calculation methodologies and/or emissions reporting structure for each of these emission source/industry segment combinations that would be needed in 40 CFR 98.233 and 98.236, respectively. For industry segments for which we are finalizing provisions to additionally require reporting of emissions from AGR vents, dehydrator vents, hydrocarbon liquids and produced water storage tank emissions, and condensate storage tank emissions, we are finalizing as proposed that reporters would use the same calculation methods and report the same information as reporters in the industry segments in which those source types are already reported. The remainder of this section describes additional amendments to 40 CFR 98.233.

For the addition of natural gas pneumatic device venting as an emission source for the Onshore Natural Gas Processing industry segment, we are finalizing as proposed that those facilities would use the calculation methodologies as described in section III.E. of this preamble. For any reporters to the Onshore Natural Gas Processing industry segment that would use Calculation Methodology 3, we are finalizing as proposed the use of the same emission factors as those used for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments. See section III.E. of this preamble for additional details about the calculation methodologies for natural gas pneumatic devices.

As noted earlier in this section, we are finalizing the addition of blowdown vent stack reporting as proposed for the Onshore Petroleum and Natural Gas Production, Underground Natural Gas Storage, LNG Storage, and Natural Gas Distribution industry segments. Subpart

[20] For example, 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–2023–0234.

[21] It should be noted that the EPA did not identify any subpart W emission sources missing from the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment.

[22] Revisions are also finalized as proposed to 40 CFR 98.232(e)(3) to reference the source as ''condensate storage tanks.''

W currently requires reporting of blowdowns either using flow meter measurements (existing 40 CFR 98.233(i)(3)) or using unique physical volume calculations by equipment or event types (existing 40 CFR 98.233(i)(2)). To allow reporters in the new industry segments to calculate emissions by equipment or event types, the EPA is finalizing as proposed the specification of the appropriate list of equipment or event types for each new segment. We are finalizing as proposed that facilities in the Onshore Petroleum and Natural Gas Production, Underground Natural Gas Storage, and LNG Storage industry segments following the methodology in 40 CFR 98.233(i)(2) are required to categorize blowdown vent stack emission events into the seven categories provided in 40 CFR 98.233(i)(2)(iv)(A), as the types of blowdown vent stack emission events for these segments are similar to those for the segments currently required to categorize under this provision. We are finalizing as proposed that facilities in the Natural Gas Distribution industry segment are required to categorize blowdowns into the eight categories listed in proposed 40 CFR 98.233(i)(2)(iv)(B), as the types of blowdowns that occur in the Natural Gas Distribution industry segment are pipeline blowdowns similar to those in the Onshore Natural Gas Transmission Pipeline industry segment. After consideration of public comments, we are also finalizing two revisions to 40 CFR 98.233(i) to provide additional provisions for Natural Gas Distribution blowdowns. First, we are revising 40 CFR 98.233(i) to specify that blowdowns in the Natural Gas Distribution industry segment with a unique physical volume of less than 500 cubic feet are not required to be reported, due to the fact that distribution mains and services operate at much lower pressures than other pipelines. Second, we are revising 40 CFR 98.233(i)(1) to require the calculation of the distribution pipeline unique physical volume in cases where a pipeline does not have isolation valves and revising the definition of the term ''V'' in equation W–14A and ''V_p'' in equation W–14B to remove the phrase ''between isolation valves.''

We are finalizing one other amendment as proposed related to the calculation of emissions from blowdown vent stacks. The EPA previously determined that for reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment using the methodology provided in existing 40 CFR 98.233(i)(2) and equation W–14A, it is reasonable to allow engineering estimates based on best available information when determining temperature and pressure for emergency blowdowns, due to the geographically dispersed nature of the facilities in this industry segment. As discussed in section III.J.3. of this preamble, we are finalizing as proposed to also allow engineering estimates based on best available information when determining temperature and pressure for emergency blowdowns for the Onshore Natural Gas Transmission Pipeline industry segment, as facilities in this industry segment are also geographically dispersed. Due to the fact that facilities in the Onshore Petroleum and Natural Gas Production and Natural Gas Distribution industry segments are similarly geographically dispersed, we are finalizing as proposed that reporters in those industry segments using the methodology provided in 40 CFR 98.233(i)(2) and equation W–14A would also be allowed to use engineering estimates based on best available information available when determining temperature and pressure for emergency blowdowns.

For the Onshore Natural Gas Transmission Pipeline industry segment, as noted earlier in this section, we are finalizing the addition of reporting of emissions from equipment leaks from transmission pipelines, transmission company interconnect metering-regulating stations, and farm tap and/or direct sale stations. The EPA is finalizing as proposed the addition of these sources to the calculation methodologies provided in 40 CFR 98.233(r) using population emission factors, with associated updates to the variable definitions in equation W–32A to include components in the Onshore Natural Gas Transmission Pipeline industry segment. We are also finalizing the addition of default CH_4 population emission factors for the components specified in this paragraph at facilities in the Onshore Natural Gas Transmission Pipeline industry segment in table W–5 to subpart W as proposed. The EPA derived these final emission factors using the 1996 Gas Research Institute (GRI)/EPA study *Methane Emissions from the Natural Gas Industry* (hereafter referred to as ''the 1996 GRI/EPA study''), specifically Volumes 9 and 10.[23] The precise derivation of the final 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–2023–0234.

After consideration of comments and consistent with CAA section 136(h) and the overall intent of this rulemaking for reporting to be based on empirical data, we are also providing the option for facilities to survey equipment components, measure leaks, and report the resulting emissions for transmission company interconnect metering-regulating stations and farm tap and/or direct sale stations using the equipment leak survey method in 40 CFR 98.233(q)(3). For the leak survey option, we are finalizing that a leak survey for transmission company interconnect metering-regulating stations and farm tap and/or direct sale stations will be considered a complete leak survey for the purposes of subpart W if all the subject equipment leak components at a station are included. We are finalizing this characterization of a complete leak survey such that a facility could survey some stations and utilize the population count method at other stations so long as every station quantifies equipment leak emissions using one of the provided methods in 40 CFR 98.233(q) or (r). This approach is consistent with the approach taken in this final rule for facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments that elect to conduct leak surveys in accordance with the provisions of 40 CFR 98.233(q) (see section III.P.3. of this preamble). For the leak survey method in 40 CFR 98.233(q), we are also finalizing that transmission pipeline facilities can develop a facility-specific leaker factor in accordance with 40 CFR 98.233(q)(4) using the leak measurements obtained in accordance with 40 CFR 98.233(q)(3). This approach is consistent with the approach for other industry segments subject to 40 CFR 98.233(q) who elect to conduct leak measurements in accordance with 40 CFR 98.233(q)(3). As explained in more detail in section III.P.4. of this preamble, the facility-specific leaker factor approach requires facilities to accumulate at least 50 measurements by component type to calculate the facility-specific leaker factor to ensure a statistically robust emission factor and accurate accounting of emissions. In response to comments, we are also finalizing a definition for the term ''transmission company interconnect

[23] *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report* (GRI–94/0257.26 and EPA–600/R–96–080i) and *Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution, Final Report* (GRI–94/0257.27 and EPA–600/R–96–080j). Gas Research Institute and U.S. Environmental Protection Agency. June 1996. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

metering-regulating station'' as well as correcting some cross-referencing errors and making minor technical corrections in the final provisions.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed addition of existing emission source types for various industry segments.

Comment: Commenters noted that distribution pipelines operate at pressures much lower than transmission pipelines, and as a result, the volume of gas blown down and emissions from a 50 cubic foot section of distribution pipe would be significantly less than the volume of gas and emissions from a transmission pipeline blowdown. One commenter noted that pressures are about a factor of 10 less than transmission pipelines, so blowdowns of equipment less than 500 cubic feet (rather than 50 cubic feet) should be exempt from reporting.

Response: To evaluate this comment, the EPA reviewed the memorandum documenting the development of the 50 cubic foot threshold, *Equipment Threshold for Blowdowns.*[24] The analysis in that memorandum was based on the volume of emissions from a typical large processing or transmission compressor operating at a pressure of 750 psig to 800 psig. In contrast, distribution systems operate at lower pressures, with gas mains typically averaging around 60 psig and small service lines that deliver gas to individual homes operating as low as 0.25 psig.[25] Therefore, because the distribution pipeline operating pressures are about a factor of 10 less than the equipment upon which the 50 cubic foot threshold was based, we are finalizing a threshold of 500 cubic feet for blowdowns in the Natural Gas Distribution industry segment.

Comment: One commenter stated that isolation valves are uncommon in the distribution segment, so it is not possible to derive a unique physical volume, and without a unique physical volume, equations W–14A and W–14B are each missing required inputs. The commenter stated that distribution line dig-in emissions are typically mitigated by pinching off the pipeline until a full repair can be completed.

Response: The EPA agrees that the requirements in 40 CFR 98.233(i)(1) for calculating unique physical volume do instruct reporters to calculate the volume between isolation valves. However, lack of isolation valves does not mean that reporters cannot calculate the physical volume of the pipeline that was isolated from operation. For example, the commenter indicated that operators typically pinch off both ends of the section of pipeline that needs repair. In this case, the reporter could use the diameter of the pipeline and the distance between the two points where the pipeline is pinched off to determine the physical volume of that section of pipeline. Therefore, we have revised 40 CFR 98.233(i)(1) to specify that for natural gas distribution pipelines without isolation valves, reporters should calculate the unique physical volume of the distribution pipeline that was isolated from operation using engineering estimates based on best available data. For other industry segments with isolation valves, the ''unique physical volume'' does not change and can be calculated prior to any blowdowns, so that the reporter knows which unique physical volumes are 50 cubic feet or greater. While a natural gas distribution reporter may not have isolation valves to pre-define a permanent unique physical volume, the reporter can determine, for each pipeline diameter they operate, what length of pipeline would result in a physical volume of 500 cubic feet or more. If the distance between the two points where the pipeline is pinched off for a repair is greater than that length, the blowdown would be required to be reported.

We are also amending the definitions of the term ''V'' in equation W–14A and ''V_p'' in equation W–14B to remove the phrase ''between isolation valves'' to account for this alternative pipeline isolation method for natural gas distribution pipelines. We note that the equations W–14A and W–14B are intended to calculate emissions for each unique physical volume, allowing for the summation of multiple blowdowns from one unique physical volume. Because the pinch-off points are not likely to be in the same location every time, reporters may have to calculate emissions from each blowdown separately. In other words, the term ''N,'' the number of occurrences of blowdowns for each unique physical volume in the calendar year, will most likely be equal to 1 for each ''unique physical volume.''

Comment: Commenters requested that direct measurement be provided as an option for transmission interconnect meter-regulating stations and farm tap/ direct sale stations. Commenters stated that providing a measurement option would result in improved accuracy of the emissions estimates for these emission sources and align with the objectives in the IRA to use empirical data. Commenters also explained that the current measurement methods could be used with the components on these stations. Some commenters suggested that companies could survey their stations using the existing subpart W methods and apply leaker factors for detected leaks in proposed table W–4 to subpart W, which are provided for transmission and underground storage stations, since the component types are similar. The commenter also suggested that facilities could perform annual surveys of their stations or the EPA could provide an option to survey stations over a multi-year survey cycle.

Response: As noted by the commenters, the only option provided in the 2023 Subpart W Proposal for transmission company interconnect metering and regulating stations and direct sale or farm tap stations was the population count method, which requires the count of stations and the use of a default population count emission factor developed using data from the 1996 GRI/EPA studies. In this rulemaking, the EPA seeks to provide calculation methods for equipment leaks from subject emission sources that are supported by available data or by providing reporters with a direct measurement option, where appropriate. Providing these options allows facilities to determine which method may be most appropriate to accurately estimate emissions while factoring the burden of the method. Generally, it is understood that direct measurement would provide the most accurate estimate of emissions, but could require significant resources to perform surveys depending on the survey method and the number of emission sources. Similarly, the use of a default population count emission factor does not provide the same level of accuracy as direct measurement, but requires lower burden (*e.g.,* count of stations and annual operating times) to estimate emissions. The EPA's ability to provide the leaker method and the population count method for estimating equipment leaks from emission sources requires the development of default leaker or default population count emission factors. The development of these emission factors is dependent

[24] U.S. EPA, *Equipment Threshold for Blowdowns,* November 2010. Available as EPA–HQ–OAR–2009–0923–3581 and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[25] American Gas Foundation, *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure,* January 2005. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

upon the availability of study data from which they can be derived.

We agree with commenters that equipment leak components at transmission company interconnect metering and regulating stations or direct sale or farm tap stations could be surveyed and directly measured using one of the methods provided in 40 CFR 98.234(a). Therefore, we are finalizing amendments in 40 CFR 98.232(m), 98.233(q), and 98.236(q) to provide that transmission pipeline companies may survey, measure, quantify and report equipment leaks from components (*i.e.,* valves, connectors, open ended lines, pressure relief valves, and meters) at transmission company interconnect metering and regulating stations or direct sale or farm tap stations using the methods in 40 CFR 98.234(a). We are finalizing that a leak survey for transmission company interconnect metering-regulating stations and farm tap and/or direct sale stations will be considered a complete leak survey for the purposes of subpart W if all the subject equipment leak components at a station are included. We are not requiring the use of the leak survey and measurement method in 40 CFR 98.233(q), rather it will be an option in addition to the population count method. Separately, we are finalizing as proposed the station level default population count emission factors in 40 CFR 98.233(r), as discussed in section III.Q. of this preamble.

However, at this time, the EPA does not have the data necessary to provide a default leaker emission factor approach for equipment leaks from stations at transmission pipeline companies (*i.e.,* transmission company interconnect metering and regulating stations; direct sale or farm tap) as the commenters have requested. While one commenter suggests that transmission pipeline companies could utilize the leaker emission factors in table W–4 to subpart W with the count of leakers at transmission company interconnect metering and regulating stations and direct sale or farm tap stations, based on our assessment, we find that the leaker emission factors in table W–4 may not be representative of the leaks from these transmission pipeline emission sources. The emission factors in table W–4 were developed and intended for components at transmission compressor stations and underground natural gas storage stations. Therefore, we are not finalizing a leaker approach for these emission sources that would use a default leaker emission factor, but we may consider providing this approach in a future rulemaking if data becomes available that could inform a default leaker emission factor set.

We also reviewed the 1996 GRI/EPA study upon which the final default population count factors for transmission company interconnect metering and regulating stations and direct sale or farm tap stations are based to determine if a default leaker emission factor could be derived from the study data. However, the study data are presented as station-level leaks rates (*i.e.,* scf/station-day). Component level leak rates were not provided in the study. Component level leak rates are needed to develop default leaker emission factors analogous to those in Subpart W for other equipment leak emissions sources.

Comment: Commenters stated that the EPA should provide additional flexibility in the quantification of emissions from transmission pipelines, including allowing a leaker emission factor approach and/or direct measurement of leak emissions.

Response: The EPA evaluated potential empirical methods for quantifying transmission pipeline leaks and determined that there is insufficient data available to develop subpart W methods that either directly quantify emissions or apply leaker emission factors to detected leaks. Although we are not aware of any published studies that include transmission pipeline leak data, Yu *et al.* (2022) [26] used quantitative aerial remote sensing surveys to quantify gathering pipeline leaks with emission rates greater than 10 to 20 kilograms of CH_4 per hour. Quantitative aerial remote sensing theoretically could be used to quantify transmission pipeline leak emissions but a direct method based on quantitative remote sensing would have very high uncertainty due to lack of data on the emission rate distribution of transmission pipeline leaks. Directly quantifying emissions would exclude an unknown fraction of total emissions that were below the survey method's detection limit. Similarly, we evaluated the available data to determine whether a leaker factor approach could be developed. As noted above, we are not aware of appropriate data for developing leaker factors for transmission pipelines. We also note that the accuracy of leaker emission factors is dependent on the method detection limit and therefore likely would need to be specific to each survey approach. The EPA intends to evaluate any data available in the future on transmission pipeline leak emission rates and determine if an empirical method can be incorporated in future updates. Another issue with quantitative remote sensing is that individual measurements of leak emission rates can have high uncertainty. Repeat measurements reduce the uncertainty, but it is not currently clear what methodology, including number of measurements, would be appropriate for accurately estimating emissions from transmission pipeline leaks. The EPA also intends to evaluate future pipeline leak data to determine what level of uncertainty and/or number of measurements is needed to accurately quantify emissions.

Comment: Commenters requested clarification of the proposed terms: Interconnect, Farm Tap and Direct Sale. The commenters requested that the EPA either provide definitions and examples of these terms in the regulatory text or in a FAQ document.

Response: The term ''Farm Tap'' is already defined in 40 CFR 98.238. The definition provided is, ''*Farm Taps* are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. In some cases, a nearby LDC may handle the billing of the gas to the customer(s).'' We note in the rule that table W–5 to subpart W groups ''Direct Sale or Farm Tap Station'' indicating that we expect the terms to be interchangeable or sufficiently carrying the same meaning, that is a station where there is a direct connect (*i.e.,* sale) from the transmission pipeline to the customer.

In reviewing Volume 10 of the 1996 GRI/EPA study upon which the final default population count emission factors are based, we find that the emission factor included in table W–5 for ''Transmission Company Interconnect M&R Station'' is based on data collected from stations, which are ''interconnects with other transmission companies to allow for flexibility of supply. The stations can flow in either direction.'' The 1996 GRI/EPA study specifically excludes transmission stations where gas is delivered to distribution companies as these are covered in the distribution segment, just as they are in subpart W where natural gas distribution companies report equipment leak emissions from transmission-distribution transfer stations. The ''Transmission Company Interconnect M&R Station'' is intended to be stations that are transmission-to-transmission interconnect points. Furthermore, these stations are characterized in the 1996 GRI/EPA study as performing metering and

[26] Yu, J., *et al.* ''Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin.'' *Environ. Sci. Technol. Lett.* 2022, 9, 969–974. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

pressure regulating with an inlet pressure above 100 psig. In order to provide clarity to the meaning of the term ''Transmission Company Interconnect M&R Station'', we are finalizing the following definition in 40 CFR 98.238: *Transmission Company Interconnect M&R Station* means a metering and pressure regulating station with an inlet pressure above 100 psig located at a point of transmission pipeline to transmission pipeline interconnect.

Comment: Commenters pointed out that there was a mismatch between equation W–32A and the emission factors provided in table W–5 to subpart W. Commenters stated that the emission factors provided in table W–5 are default methane population emission factors. Commenters stated that the variable ''GHGi'' for transmission pipeline sources provided in 40 CFR 98.233(r) was proposed as equaling 0.975 for CH_4 and 0.011 for CO_2. Commenters requested that the EPA revise the equation or the factors for consistency and clarity.

Response: We agree with commenters that there was an inadvertent error in adding onshore natural gas transmission pipeline to the list of sources in the variable ''GHGi'' of equation W–32A in 40 CFR 98.233(r). We are finalizing a correction that will move the addition of ''onshore natural gas transmission pipeline'' to be grouped with a methane concentration of 1 and a carbon dioxide concentration value of 0.011 in the variable ''GHGi'' of equation W–32A in 40 CFR 98.233(r), consistent with the application of the default methane emission factors, which we are finalizing as proposed.

2. Nitrogen Removal Units

The EPA is finalizing as proposed revisions to 40 CFR 98.232, 98.233(d), and 98.236(d) to add calculation and reporting requirements for CH_4 emissions from nitrogen removal units used in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Petroleum Natural Gas Gathering and Boosting, LNG Storage, and LNG Import and Export Equipment industry segments. Nitrogen removal units remove nitrogen from the raw natural gas stream to meet pipeline requirements and for compressing natural gas into LNG.[27] [28] The nitrogen removal unit typically follows in series after other process units that remove acid gas (*e.g.,* CO_2, hydrogen sulfide), water, and heavy hydrocarbons. The EPA received only minor comments regarding the addition of nitrogen removal units. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

The EPA is finalizing as proposed the definition of ''nitrogen removal unit'' in 40 CFR 98.238 as a process unit that separates nitrogen from natural gas using various separation processes (*e.g.,* cryogenic units, membrane units). The EPA is finalizing a definition of ''nitrogen removal unit vent emissions'' as the nitrogen gas separated from the natural gas and released with CH_4 and other gases to the atmosphere. The proposed definition of this term also included nitrogen gas released to a flare or other combustion unit, similar to the definition of ''acid gas removal unit vent emissions.'' However, as described later in this section, gas from a nitrogen removal unit routed to a flare or routed to combustion will be reported separately as flared emissions or combustion emissions, respectively, so the final definition of ''nitrogen removal unit vent emissions'' includes only the vent gas released to the atmosphere. The EPA is finalizing as proposed the amendments to 40 CFR 98.232(c)(17), 98.232(d)(5), 98.232(g)(10), 98.232(h)(9), and 98.232(j)(3) to add nitrogen removal unit vents to the list of source types for which the industry segments previously specified will be required to report emissions and is finalizing as proposed the corresponding additions at 40 CFR 98.236(a) to add nitrogen removal units to the list of equipment and activities that will be reported for each of these industry segments.

The EPA is finalizing CH_4 emission calculation methodologies for nitrogen removal units that are nearly identical to the final calculation methodologies in 40 CFR 98.233(d) for AGRs. These methods include use of vent meters, engineering calculations based upon flow rate and composition of gas streams, or calculation using simulation software. The final amendments to the AGR calculation methodologies are largely the same as proposed, with some additional clarifications regarding applicability of the calculation methods and provisions to address vents routed to vapor recovery systems. The only difference between the final calculation methodologies for CH_4 emissions from AGRs and nitrogen removal units is that any nitrogen removal unit with a vent meter installed must use Calculation Method 2; the new provision allowing use of Calculation Method 4 for AGRs with a vent meter does not apply to nitrogen removal units. Comments on and a more detailed discussion regarding the amendments to the AGR calculation methodologies, which are relevant to nitrogen removal units calculation methodologies as well, are addressed in section III.F.1. of this preamble. Further, the EPA is finalizing as proposed the addition of relevant reporting elements for CH_4 emissions from nitrogen removal units to 40 CFR 98.236(d) for each of the allowable calculation methodologies.

The EPA is finalizing as proposed the requirements that emissions from nitrogen removal unit vents routed to a flare (CO_2, CH_4, and N_2O) will be reported under 40 CFR 98.236(n) separately from vented nitrogen removal unit emissions (CH_4). We note that, as explained in section III.N. of this preamble, the EPA is finalizing requirements for determining the flow and composition of the gas routed to a flare that differ from those proposed in 40 CFR 98.233(n) that also affect AGRs and nitrogen removal units. Under the final rule, the flared nitrogen removal unit emissions are included with ''other'' flared source types for purposes of the disaggregation provisions in 40 CFR 98.233(n)(10) and 40 CFR 98.236(n)(19), as proposed. See section III.N. of this preamble for more information on the flaring calculation and reporting provisions, including changes from the proposed requirements that affect AGRs and nitrogen removal units.

3. Produced Water Tanks

a. Summary of Final Amendments

As discussed in the 2023 Subpart W proposal, in the 2022 U.S. GHG Inventory emissions estimate for 2020, the EPA estimated approximately 140,300 metric tons of CH_4 emissions from produced water tanks associated with natural gas wells and 88,600 metric tons of CH_4 emissions from produced water tanks associated with oil wells. Therefore, consistent with section II.A. of this preamble, the EPA is finalizing as proposed amendments to 40 CFR 98.233(j) to require reporters with

[27] Kuo, J.C., K.H. Wang, C. Chen. Pros and cons of different Nitrogen Removal Unit (NRU) technology. 7 (2012) 52–59. *Journal of Natural Gas Science and Engineering.* July 2012. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[28] Park, J., D. Cho. Decision methodology for nitrogen removal process in the LNG plant using analytic hierarchy process. *Journal of Industrial and Engineering Chemistry.* 37 (2016) 75–83. 2016. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

atmospheric pressure storage tanks receiving produced water to calculate CH_4 emissions using any of the three calculation methodologies specified in 40 CFR 98.233(j)(1) through (3). Industry segments required to report emissions from produced water tanks would include Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Processing. The EPA is finalizing the definition of ''produced water'' as proposed, which is the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

For facilities with produced water storage tanks electing to model their CH_4 emissions consistent with 40 CFR 98.233(j)(1), the EPA is finalizing revisions as proposed to allow facilities to select any software option that meets the requirements currently stated in 40 CFR 98.233(j)(1) (*i.e.,* to select a modeling software that uses the Peng-Robinson equation of state, models flashing emissions from produced water, and speciates CH_4 emissions that result when the produced water from the separator or non-separator equipment enters an atmospheric pressure storage tank). We are finalizing revisions to 40 CFR 98.233(j)(1) as proposed to state that API's E&P Tanks should only be used for modeling atmospheric storage tanks receiving hydrocarbon liquids.

For stuck dump valve emissions associated with produced water tanks, we proposed that calculation of these emissions would not be required when using Calculation Method 3. Additionally, no correction factor was proposed for use in equation W–16 to calculate stuck dump valve emissions associated with produced water tanks in Calculation Methods 2 and 3. Therefore, and after consideration of comments received, the EPA is revising from proposal the introductory paragraph in 40 CFR 98.233(j) to, at this time, only require calculation and reporting of emissions from hydrocarbon liquid stuck dump valves per 40 CFR 98.233(j)(5).

As described in section III.K.5. of this preamble, the EPA is finalizing that reporters would collect measurements of the simulation input parameters listed under 40 CFR 98.233(j)(1) for produced water tanks, with changes from proposal described in section III.K.5. of this preamble. In addition, after consideration of comments received and the technical challenges with measuring entrained oil in produced water, the EPA is finalizing updates from proposal that facilities may elect to use a representative hydrocarbon liquid composition and assume oil entrainment of 1 percent or greater rather than collecting a produced water sample.

The EPA is finalizing as proposed the addition of CH_4 emission factors to 40 CFR 98.233(j)(3) that were developed as part of the 1996 GRI/EPA study, which is consistent with the factors used by the U.S. GHG Inventory. The final emission factors were sourced from the 2021 API Compendium (table 6–26), which provides emission factors from the 1996 GRI/EPA study converted from units of million pounds per year to units of metric tons per thousand barrels (based upon the assumption of 497 million barrels of produced water annual production). Average emission factors are provided for pressures of 50, 250, and 1,000 pounds per square inch. The EPA expects that these factors, which were developed using process simulation at different pressures, are sufficiently representative of produced water tank emissions. Furthermore, the EPA is not aware of any other emission factors for produced water tank emissions, nor are we aware of studies or data that would allow us to develop different emission factors.

We are also finalizing reporting requirements for produced water tanks as proposed. We are finalizing revisions to 40 CFR 98.236(j)(1) as proposed to refer to both hydrocarbon liquid and produced water atmospheric storage tanks. Additionally, we are finalizing the addition of 40 CFR 98.236(j)(2) as proposed to require reporting of total annual produced water volumes for each pressure range, estimates of the fraction of produced water throughput that is controlled by flares and/or vapor recovery, counts of controlled and uncontrolled produced water tanks, and annual CH_4 emissions vented directly to atmosphere from produced water tanks.

The EPA is also finalizing as proposed the revision of the emission source type name in 40 CFR 98.233(j) and 40 CFR 98.236(j) from ''onshore production and onshore petroleum and natural gas gathering and boosting storage tanks'' to ''hydrocarbon liquids and produced water storage tanks'' to reflect the proposed addition of produced water tanks. Consistently, the EPA is also finalizing as proposed revisions to the source type provided in 40 CFR 98.232(c)(10) and 40 CFR 98.232(j)(6) to ''Hydrocarbon liquid and produced water storage tank emissions,'' which reflect the addition of produced water tanks.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add produced water tanks as an emission source for the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments.

Comment: One commenter proposed limiting the required emission calculations for produced water tanks to emissions associated with stuck dump valves. Another commenter additionally noted that the EPA provides a stuck dump valve emission factor for produced water tanks if Calculation Method 1 or 2 is used, but no factor is provided for tanks using Calculation Method 3.

Response: The EPA does not agree that produced water tank emissions should be limited to only those emissions associated with stuck dump valves. In the 2022 U.S. GHG Inventory emissions estimate for 2020, the EPA estimated approximately 140,300 mt CH_4 emissions from produced water tanks associated with natural gas wells and 88,600 mt CH_4 emissions from produced water tanks associated with oil wells. These emissions would not be fully represented in subpart W by only requiring reporting of emissions from produced water tanks with stuck dump valves; in other words, this approach would not result in accurate reporting of total emissions.

As proposed, calculation of emissions from stuck dump valves per 40 CFR 98.233(j)(5) would not be required for produced water tanks using Calculation Method 3. Additionally, the EPA has reviewed the inputs to equation W–16 and notes that the correction factor, CF_{dv}, is provided for only separators in crude oil and condensate production for Calculation Methods 1 and 2. Finally, the EPA is not aware of published methodologies for estimating stuck dump valve emissions associated specifically with produced water tanks. Therefore, after consideration of comments received, the EPA is revising from proposal the introductory paragraph in 40 CFR 98.233(j) to not require at this time calculation of emissions from stuck dump valves for produced water tanks using any of the three calculation methodologies and only require calculation and reporting of emissions from hydrocarbon liquid stuck dump valves per 40 CFR 98.233(j)(5).

Comment: Several commenters noted burden associated with collection of pressurized liquid samples and other measurements from produced water storage tanks. Additionally, one commenter recommended allowing operators to assume that produced water tanks contain 1 percent of the oil content. They noted that this would allow for consistency with Texas Commission on Environmental Quality (TCEQ) Emissions Representation for Produced Water guidance,[29] which describes that oil or condensate floats on top of the water phase and contributes to the partial pressure within the tank.

Response: The EPA is finalizing a revision from the proposal for a reduced frequency schedule for composition and Reid vapor pressure sampling and analysis from each well, separator, or non-separator equipment. Reporters must sample and analyze hydrocarbon liquids or produced water composition and Reid vapor pressure at least once every 5 years. Additional details are provided in section III.K.5. of this preamble.

Additionally, for produced water tanks, the EPA recognizes that industry standard is to assume one percent oil entrainment for produced water.[30 31] The premise behind the one percent assumption is that entrainment from upstream separation introduces hydrocarbon liquids into the produced water tank. This entrained material forms a layer of hydrocarbons that float on top of the water in the tank and is expected to increase total emissions, and the EPA recognizes that it is technically challenging to accurately measure the entrained oil content in the water fed to the tank. Thus, facilities often use the produced water flowrate and the composition of the associated hydrocarbon streams when performing the flash emission calculations. Flash emissions from produced water tanks are then determined by multiplying the flash emission calculation results by one percent.

The EPA agrees with requests from commenters that one percent entrainment is an acceptable assumption to represent flashing emissions from produced water tanks given the difficulty with accurately quantifying oil entrainment in produced water. We are therefore adding language in 40 CFR 98.233(j)(1)(vii) and 40 CFR 98.233(j)(2)(i) of the final rule that for produced water composition, reporters may elect to use a representative hydrocarbon liquid composition and assume oil entrainment of 1 percent or greater rather than collecting a produced water sample every 5 years.

4. Mud Degassing

a. Summary of Final Amendments

The EPA is adding a new emission source type to subpart W for emissions from drilling mud degassing. The term ''drilling mud,'' also referred to as ''drilling fluid,'' refers to a class of viscous fluids used during the drilling of oil and gas wells. As drilling mud circulates through the wellbore, natural gas and heavier hydrocarbons can become entrained in the mud. Mud degassing refers to the practice of extracting the entrained gas from drilling mud once it is outside the wellbore. The new provisions add calculation and reporting requirements for CH_4 emissions from mud degassing associated with well drilling for onshore petroleum and natural gas production facilities in 40 CFR 98.232(c), 98.233(dd), and 98.236(dd). In addition, several new definitions for terms related to mud degassing are being added to 40 CFR 98.238. The EPA is only requiring the reporting of CH_4 emissions from this source because CH_4 is the primary GHG emitted from this source, while emissions of CO_2 are expected to be very small.

The EPA is finalizing the revision to 40 CFR 98.232(c) as proposed, and the revisions to 98.233(dd) and 98.236(dd) with changes to those proposed, including the addition of a third calculation method that must be used in certain circumstances and corresponding reporting requirements, so that reporters have three calculation methods that apply as specified in those provisions to calculate emissions from mud degassing in new 40 CFR 98.233(dd).

More specifically, the final provision includes two important changes from proposal for the requirement to use Calculation Method 1 when the reporter has taken mudlogging measurements. First, the final rule adds the further qualification that Calculation Method 1 is required when measurements are taken once the first hydrocarbon bearing zone has been penetrated until drilling mud ceases to be circulated in the wellbore, because natural gas is unlikely to become entrained in drilling fluids until the first hydrocarbon zone is penetrated. Second, the final rule adds that Calculation Method 1 is required when gas-trap derived gas concentration from mudlogging measurements is reported in parts per million (ppm) or is reported in units from which ppm can be derived.

Additionally, the final Calculation Method 1 includes several additional changes from proposal. We have replaced the term ''at the same approximate depth'' with ''within the equivalent stratigraphic interval'' to use more widely recognized geologic terminology and to recognize that formation properties are more directly related to stratigraphy than to depth below surface. We are also adding this term to 40 CFR 98.238, Definitions, and defining the term as ''the depth of the same stratum of rock in the Earth's subsurface.'' Other changes to Calculation Method 1 include clarifications in the definitions of ''T_r'' in equations W–41 and W–42, and ''T_p'' in equation W–43 to specify that total time that drilling mud is circulated in the well begins with initial penetration of the first hydrocarbon-bearing zone rather than when the well is spudded at the surface, and until drilling mud ceases to be circulated in the wellbore. We are also amending the term X_n in equation W–41 to be the ''average'' gas concentration. The use of the average gas concentration should ensure consistency with the use of the average mud rate in equation W–41 and result in emissions calculations that are representative of average conditions throughout the drilling cycle.

Consistent with the proposal, the final Calculation Method 1 requires the reporter to calculate CH_4 emissions and a CH_4 emissions rate from mud degassing for a representative well and then to apply that rate to other wells in the sub-basin and within the equivalent stratigraphic interval. To qualify as a representative well, we are finalizing that the well is required to be drilled in the same sub-basin and within the equivalent stratigraphic interval from the surface (instead of at the same approximate total depth, as proposed) as the wells for which it is representative.

Under the final provisions, as proposed, the operator is required to identify and calculate natural gas emissions for a representative well at least once every 2 years for each sub-basin and equivalent stratigraphic interval within the facility to ensure that the emissions from representative wells are representative of the operating and drilling practices within each applicable sub-basin in the facility. In the first year of reporting, however, the operator may use measurements from the prior

[29] *Emission Representations for Produced Water.* Texas Commission on Environmental Quality. Available at: *https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/produced-water.pdf* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[30] *Id.*

[31] *Are Produced Water Emission Factors Accurate?* Bryan Research & Engineering, Inc. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

reporting year if measurements from the current reporting year are not available.

Under the final provisions, if mudlogging measurements were not taken or were taken but did not produce gas concentration in ppm or in units from which ppm can be derived, reporters must use Calculation Method 2 to determine emissions from mud degassing using equation W–44, which incorporates the nationwide emission factors provided by the CenSARA study.[32] Specifically, emissions are calculated using an emission factor of 0.2605 mt CH_4 per drilling day per well for water-based mud and a factor of 0.0586 mt CH_4 per drilling day per well for oil-based and synthetic drilling muds. After consideration of comments, the EPA is finalizing Calculation Method 2 with two notable changes from the proposal. The final equation W–44 now includes an adjustment to local conditions by taking the ratio of the local CH_4 mole fraction, which will consist of the average mole fraction of CH_4 in produced gas for the sub-basin reported under 40 CFR 98.236(aa)(1)(ii)(I), (X_{CH4}), to the nationwide mole fraction of 83.35 used to derive the emission factors. This adjustment for local conditions will more accurately reflect facility-specific emissions compared to relying solely on nationwide emission factors as originally proposed. The second change affects the number of drilling days, DD_p, in equation W–44. Entrainment of gas in drilling mud and resulting emissions are unlikely if mud is not circulating, which can occur for many reasons during the drilling of a well; for example, if drilling ceases due to a well workover, implementation of health and safety protocols, equipment failure, or for other reasons. Therefore, in the final rule, the number of drilling days used in equation W–44 is the actual number of days drilling mud is circulated in the wellbore.

In addition to the two calculation methods that were proposed, we are finalizing Calculation Method 3, which must be used when mudlogging measurements are taken during some, but not all, of the time the well bore has penetrated the first hydrocarbon bearing zone and until drilling mud ceases to be circulated in the wellbore. Under Calculation Method 3, Calculation Method 1 must be used to calculate emissions for the cumulative amount of time mudlogging measurements were taken and Calculation Method 2 must be used for the cumulative amount of time mudlogging measurements were not taken. The emissions derived from each are added together for Calculation Method 3.

In addition to the calculation requirements, the EPA is finalizing corresponding reporting requirements for emissions by well in 40 CFR 98.236(dd) as proposed, except that reporters using Calculation Method 1 must report the target hydrocarbon-bearing stratigraphic formation to which the well is drilled in addition to the total vertical depth of the well to allow for adequate verification of reported mud degassing emissions. We have added a definition for target hydrocarbon-bearing stratigraphic formation in 40 CFR 98.238 to mean the stratigraphic interval intended to be the primary hydrocarbon producing formation. The final reporting requirements for mud degassing also include reporting requirements for reporters using Calculation Method 3, which require the reporter to indicate if this method was used and to report the required Calculation Method 1 data elements for the time periods when Calculation Method 1 was used and the required Calculation Method 2 data elements when Calculation Method 2 was used.

The other change from the proposed reporting requirements affects several data elements in Calculation Method 1, based on the EPA's review and consideration of public comments. The EPA proposed that all of the Calculation Method 1 data elements identified as inputs to emission equations should be directly reported without a 2-year delay. In the final rule, there are several Calculation Method 1 inputs to emission equations for which reporting may be delayed by 2 years. Specifically, the Average concentration of natural gas in the drilling mud (X_n), the Measured mole fraction of CH_4 the natural gas (GHG_{CH4}), and the Total time that drilling mud is circulated in the well (T_r in equations W–41 and W–42 and T_p in equation W–43) are eligible for the 2-year delay for any well that is a wildcat and/or delineation well. The 2-year delay is also available for the Average mud rate (MR_r) and the Calculated CH_4 emissions rate ($ER_{sCH4,r}$) when one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42) is applied is a wildcat and/or delineation well. In addition, reporting of the Total time that drilling mud is circulated in the well (Tr in equations W–41 and W–42) may be delayed for 2 years for the representative well if one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42) is applied is a wildcat and/or delineation well. Wildcat and delineation wells are considered exploratory wells in the oil and gas industry, and data from these wells are generally considered sensitive information by the industry. State oil and gas commissions commonly hold such data from public release for two years. Therefore, the EPA has determined that these inputs to emission equations should be directly reported but are subject to a 2-year delay for exploratory wells to acknowledge the sensitive nature of the data and to ensure that the data cannot be back calculated prior to the end of the 2-year delay. However, we emphasize that this information would be considered to be emission data under CAA section 114 that is not eligible for confidential treatment upon submission to the agency, and thus will be made available to the public upon submission. Furthermore, emissions from any well with well degassing must still be reported annually and we further note that we have other information that will allow verification of reported emissions. Moreover, the EPA intends to be diligent in reviewing and reconciling delayed data with reported emissions data, and we also stress that, although the delayed data may not be reported in the initial reporting year, reporters must maintain records supporting their emission calculations and these records are subject to review by the EPA. Finally, the EPA intends to further evaluate whether this information will be required and, if so, may require reporting without delay in a future rulemaking.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add mud degassing as an emission source for onshore petroleum and natural gas production facilities.

Comment: Some commenters supported the addition of mud degassing as a source, while other commenters questioned the inclusion of mud degassing as an emissions source of CH_4 and CO_2, stating that the EPA has not taken due account of the difficulties and costs associated with measuring methane emissions from drilling mud degassing. In addition, one commenter suggested that the EPA has not considered the ability of reporters to

[32] 2011 *Oil and Gas Emission Inventory Enhancement Project for CenSARA States.* Produced by ENVIRON International Corporation for Central States Air Resources Agencies. November 2011. Available at *https://www.deq.ok.gov/wp-content/uploads/air-division/EI_OG_Final_Report_CenSara_122712.pdf* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

accurately capture such emissions as required by the IRA. The commenters recommended that the EPA not finalize mud degassing in subpart W.

Response: At this time, we agree with the commenters that CO_2 emissions are unlikely to be significant from this source, and the EPA did not propose and is not finalizing requirements to calculate and report CO_2 emissions from drilling mud degassing in this final rule. Under the final provisions, only CH_4 emissions will be reported for drilling mud degassing from the onshore production segment as the EPA considers mud degassing to be a potentially significant source of CH_4 emissions from the onshore production segment. Several notable guidelines on oil and gas emission sources include mud degassing emissions as a source of GHG emissions and provide calculation methods for estimating mud degassing emissions from the onshore production segment, including API, the Central States Air Resources Agencies (CenSARA), and the New York State Energy Research and Development Authority (NYSERDA). The EPA further notes that CenSARA and NYSERDA guidelines use the same emission factors, which are based on a paper published by the EPA in 1977 entitled ''Atmospheric Emissions from Offshore Oil and Gas Development and Production.'' This paper estimated two total hydrocarbon (THC) emission factors (EFs), for water-based mud and oil-based mud degassing. Thus, we believe that it should be included as an emissions source in reporting for the onshore production segment to best ensure accurate reporting of total methane emissions from the facilities. We are, therefore, finalizing that onshore production reporters are required to report CH_4 emissions from drilling mud degassing.

Regarding the commenter's assertion that the EPA has not considered the ability of reporters to accurately capture such emissions, we note that when proposing and finalizing the rule, the EPA considered the potential challenges associated with taking measurements from mud degassing. We understand that field and operational conditions may impact a reporter's ability to take measurements at the well site or there may be instances when mud logging is not used. Consistent with the proposal, the final rule does not require measurement of CH_4 emissions from mud degassing, but only that measured data be used to calculate emissions using Calculation Method 1 if measurements are taken. When measurement data are not available, the proposed and final rule provide additional flexibility by allowing reporters to use the engineering equations in Calculation Method 2 with default emission factors for oil-based, water-based and synthetic drilling muds. In addition, as discussed in the response to comments later in this section, the EPA is providing additional flexibility by finalizing a new Calculation Method 3, which requires use of Calculation Method 1 when mudlogging measurements are taken at intermittent time periods during mud circulation while requiring use of Calculation Method 2 for those time intervals when mudlogging measurements are not taken.

Comment: The EPA received several comments requesting clarification of the term ''same approximate total depth'' as it was used in the proposed rule for Calculation Method 1 and how to determine same approximate depth.

Response: The EPA agrees with the commenters that the term ''same approximate total depth'' as used in the proposed rule could be further clarified. We are finalizing the rule with the term ''equivalent stratigraphic interval'' instead of the proposed term ''same approximate total depth'' to provide more certainty to the meaning of the term. ''Equivalent stratigraphic interval'' is a term and concept that should be familiar to professionals in the oil and gas industry and others with a basic understanding of geology. It refers to the depth to a specific layer of rock in the Earth's subsurface. Since the depth of a specific strata can vary due to ground elevation, layer dip, or subsurface discontinuities, it is often useful to refer to the equivalent stratigraphic interval as opposed to true vertical depth, sub-sea depth or more general terms including approximate depth. More importantly, it clearly reflects the intent of the regulations in using this term, which is to measure and apply the emissions rate from a representative well to all others in the same producing formation. We also note that stratigraphic depth can be correlated with geophysical data such as seismic data. Additionally, the term ''equivalent stratigraphic interval'' is defined in the final rule as ''the depth of the same stratum of rock in the Earth's subsurface.'' In the final provisions, we have replaced ''same approximate total depth'' with ''equivalent stratigraphic interval'' where the term appeared in 40 CFR 98.233(dd) and 98.236(dd) of the proposed rule. In addition, we added the definition of equivalent stratigraphic interval to 40 CFR 98.238, Definitions. Complimentary to this change, in 40 CFR 98.236(dd)(1) of the final rule we are requiring reporters to report the target hydrocarbon-bearing stratigraphic formation for each well, including the representative well, when Calculation Method 1 is used. We have also added a definition for this term in 40 CFR 98.238 to mean the stratigraphic interval intended to be the primary hydrocarbon producing formation. This reporting requirement will allow for adequate verification of mud degassing emissions.

Comment: Commenters stated that the EPA has proposed that operators must use mudlogging measurements taken during the reporting year, and therefore calculate emissions using Methodology 1. The commenters disagreed with this requirement, claiming that it is possible a mudlogging measurement is taken at the very early stages of a drilling operation, and that measurement may not ultimately be reflective of the entire duration of the drilling operation. The commenters recommended allowing reporters to use Calculation Method 2 for all active drilling and proposed a third option in the event that some mudlogging data is available. Commenters stated that the third option would allow operators to use a combination of the two methodologies when a varying level of directly measured data is available. Commenters stated that, in this third option, mudlogging measurements would be used based on Method 1 for the period in which the data are available, and Method 2 would be used for the remaining period of drilling activity where mudlogging data are not available.

Response: The EPA did not propose that operators must use mudlogging equipment, only that if mudlogging equipment is used then reporters must use Calculation Method 1 and this approach is adopted in the final rule. In response to a comment that is addressed later in the preamble, we are providing additional clarity in the final rule with respect to applicability of Calculation Method 1. The final rule adds that Calculation Method 1 is required when reporters have taken mudlogging measurements, including mud pumping rate and gas trap-derived gas concentration that is reported in parts per million (ppm) or is reported in units from which ppm can be derived. Consistent with the proposal, the final rule requires the reporter to use emission factors if mudlogging measurements are not taken.

The EPA also disagrees with the commenter that mudlogging measurements are not representative of the drilling cycle because they may only be taken at the early stages of drilling. Proposed equation W–41 used the average mud rate for the representative well, r, in gallons per minute, rather than a single point measurement to determine methane emissions from mud degassing. In considering this comment, however, the EPA determined that the definition of the term X_n in equation W–41 should be the ''average'' gas concentration in the drilling mud as measured by the gas trap, in parts per million (adding ''average'' to the proposed term in the final equation). The final provisions to use the average gas concentration should ensure consistency with the use of the average mud rate (MR_r), resulting in emissions calculations that are based on average measurements that allow for fluctuations in concentrations and flows inherent in field operations.

The EPA disagrees with the commenter's suggestion that all reporters be allowed to use Calculation Method 2 regardless of whether mudlogging was performed for at least one well. Consistent with CAA section 136(h), the overall intent of this rulemaking is for reporting to be based on empirical data and have greater accuracy of total emissions data from facilities. Therefore, the final provisions include a modification from proposal to require that reporters use Calculation Method 1 if they take mudlogging measurements for the entire time period from the penetration of the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore. This requirement applies only if the mudlogging measurements provide a gas concentration in ppm or in units from which ppm can be derived. If a reporter does not use mudlogging, then reporters must use the emission factors in Calculation Method 2. After considering this comment, the EPA is finalizing a third method that requires operators to use a combination of the two methodologies when a varying level of directly measured data is available. For example, where mudlogging was only used at certain intervals during drilling an individual well, the third method would apply and the reporter would use Calculation Method 1 during those intervals while applying Calculation Method 2 to the other drilling periods. The EPA is finalizing this hybrid method as a new Calculation Method 3 in 40 CFR 98.233(dd)(3), that requires use of Calculation Method 1 when mudlogging measurements are available and use of Calculation Method 2 for the remaining period of drilling activity where mudlogging data is not available.

Comment: Commenters requested that the EPA clarify that the total time that drilling mud is circulated in the representative well in Calculation Method 1 should be calculated based on circulating time in the hydrocarbon bearing zones only (*i.e.,* excluding surface holes drilled by a spudder rig when no hydrocarbons are present).

Response: The EPA agrees that the final definition of T_r and T_p in Calculation Method 1, ''Total time that drilling mud is circulated in the representative well in minutes,'' should be amended from proposal to reflect that time of mud circulation in equations W–41, W–42, and W–43 does not begin until the first hydrocarbon-bearing zone is penetrated by the well bore. This change is consistent with the first day of drilling days, DD_p, in Calculation Method 2, which is the first day that the borehole penetrated the first hydrocarbon-bearing zone. The final rule reflects these changes from proposal to Calculation Method 1.

The EPA disagrees with the suggestion to clarify that ''total time that drilling mud is circulated in the representative well'' should be calculated based on circulating time in the hydrocarbon bearing zones only. Hydrocarbons can still become entrained in drilling mud even after the well bore moves out of the hydrocarbon-bearing zone. The use of an average mud rate and average natural gas concentration combined with the change from proposal just described, to only consider the start of mud circulation to be the time when the first hydrocarbon zone is penetrated, should appropriately address the commenter's concerns.

Comment: Commenters stated that a further complication of the proposed method for quantifying methane emissions from drilling mud degassing is that the concentration of natural gas (or methane) in drilling mud is not currently specifically measured and is difficult to obtain. Further, commenters stated it is not measured by mud loggers in units of ppm, as the measurement instrument used is in units that are not representative of methane concentration.

Response: The EPA acknowledges that some mudlogging equipment may use units that are not convertible to ppm. Therefore, we have further qualified the use of Calculation Method 1 to be required if you have taken mudlogging measurements from the penetration of the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore, including mud pumping rate and gas trap-derived gas concentration that is reported in parts per million (ppm) or is reported in units from which ppm can be derived. We further note that reporters must use Calculation Methodology 2 emission factors if they do not take mud logging measurements as described above. The EPA disagrees that the concentration of natural gas in drilling mud is not specifically measured and is difficult to obtain. Mudlogging equipment capable of measuring gas concentration and in ppm is available. Even when other available mudlogging equipment does not produce data in these units, the mudlogging equipment may use specific units based on their sensors and calibration that are convertible to percent or ppm. Therefore, the final rule retains the requirement to use these measurements when available under Calculation Method 1 or Calculation Method 3.

Comment: Commenters expressed concern that the proposed emission factors in Calculation Method 2 are dated and based on offshore wells. Commenters suggested that the EPA instead adopt emission factors for drilling mud degassing in the American Petroleum Institute's (API) Compendium.[33] Commenters also expressed concern that the proposed rule did not allow for adjustments to emission factors in Calculation Method 2 based on local conditions. Commenters noted that mud weight is critical in controlling formation pressure and the flow of hydrocarbons into the well bore during the drilling process and the various methods do not account for this. A commenter also suggested that the emission factors should be derived as a function of well dimensions to better represent mud degassing emissions. The commenter stated that, otherwise, proposed Calculation Methodology 2 should be revised based on drilling time in the hydrocarbon hole section, and not overall event days. The commenter stated that there can be multiple days in a hydrocarbon hole section where the pumps are not circulating.

Finally, a commenter noted that the EPA proposes to define the number of drilling days differently than the CenSARA study. The commenter stated that rather than considering the first drilling day to be the day the well is spudded, the EPA proposed that the total number of drilling days is the sum of all days from the first day that the borehole penetrates the first

[33] *Compendium of Greenhouse Gas Emissions Methodologies For The Natural Gas And Oil Industry.* Produced by URS Corporation for American Petroleum Institute. November 2021. Available at *https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

hydrocarbon-bearing zone through the completion of all drilling activity.

Response: In proposing emission factors for drilling mud degassing, the EPA considered the sources available with published emission factors. As the commenter notes, API does include emission factors in Section 6.2.1 of its Compendium of Greenhouse Gas Emission Methodologies for the Natural Gas Industry. The API emission factors are lower than those included in the CenSARA guidelines; however, the factors are based on API member comments on a letter from API submitted to the EPA in 2020 with respect to mud degassing emission factors being considered for the U.S. Inventory of Greenhouse Gas Emissions. See Section 6.2.1 of the API Compendium. The commenter has not submitted documentation to support the recommended emission factors other than reference to the API Compendium based on API member comments. This does not allow the EPA to further investigate the derivation of the API emission factors. In contrast, the basis for emission factors used in the CenSARA and NYSERDA guidelines is a 1977 study by the EPA's Office of Air Quality Planning and Standards, which derived emission factor based on engineering equations. The methodology is public and has been subject to review. We acknowledge that the factors are based on offshore operations; however, we believe they present a reasonable approximation of onshore emissions. We note that the final rule provides reporters with the option to take site-specific measurements and use measured data if they do not believe the emission factors, adjusted for local conditions, accurately represent emissions from mud degassing from their wells. Therefore, our assessment of the available information is that the proposed emission factors (from the published CenSARA study) are appropriate and we are including them in the final provisions.

For Calculation Method 2, the EPA generally agrees with the commenter that adjustment for local conditions may more accurately reflect emissions at the facility than reliance solely on nationwide emission factors. The CenSARA guidelines allow for local adjustment of CH_4 emissions by applying the ratio of the measured CH_4 mole fraction to the mole fraction used to develop the emission factor, 83.85,[34] although the guidelines do not specify how the measurement is derived. The EPA believes allowing for adjustment to local conditions is a reasonable approach when using an emission factor and is finalizing the rule with such an adjustment from proposal to Calculation Method 2. Specifically, we are adding two data inputs to equation W–44. The first is X_{CH4}, which is the CH_4 mole fraction in the sub-basin. The CH_4 mole fraction used in equation W–44 will be the mole fraction for the sub-basin as reported for the onshore production facility in 40 CFR 98.236(aa)(ii) because, for a reporter using Calculation Method 2, the reporter has not taken mudlogging measurements including gas concentration. The second data input is the nationwide CH_4 mole fraction of 83.85. Reporters using Calculation Method 2 will multiply the number of drilling days by the appropriate emission factor as defined in equation W–44. That value will then be multiplied by the ratio of X_{CH4} to 83.35 to derive emissions from mud degassing.

The EPA disagrees with the commenters that mud weight should be considered in the emission factors in Calculation Method 2 and in Calculation Method 1. Calculation Method 1 effectively takes mud weight into account because it uses direct measurement. For example, if mud weight is high, or overbalanced, the amount of gas entering the mud stream is reduced and the average gas concentration will decrease. If mud weight is low, or underbalanced, the gas concentration in the drilling mud will increase. For Calculation Methodology 2, none of the available methodologies identify the mud weight used to determine the emission factors; therefore, it is not possible to modify the emission factors by applying a specific mud weight to the emission factor. Separate emission factors for water-based, oil-based and synthetic drilling muds should address the commenters' concern.

The EPA does not agree with the commenter's suggestion for Calculation Method 2 to consider well dimensions to better represent mud degassing emissions. Well dimensions alone do not determine the quantity of emissions that may result from mud degassing. Use of separate emission factors for water-based, oil-based and synthetic muds and allowing use of site-specific CH_4 mole fractions provide flexibility to develop more site-specific emissions for mud degassing using Calculation Method 2. However, the EPA does agree with the commenter that the definition of drilling days, DD_p, in equation W–44 should be revised to reflect the actual number of days drilling mud is circulated in the wellbore. This change is consistent with how the EPA defines the last drilling day, which is the day drilling mud ceases to be circulated in the wellbore. Entrainment of gas in drilling mud and resulting emissions are unlikely if mud is not circulating. There are many reasons why an operator may stop mud pumping on a well site including mechanical reasons, well workovers, health and safety issues, and other reasons.

With respect to the number of drilling days in Calculation Method 2 and the comment that the EPA had changed the start of drilling days from CenSARA definition (which is the date the well is spudded), the EPA proposal intended to add clarity to Calculation Method 2 by proposing the first drilling day as the day that the borehole penetrated the first hydrocarbon-bearing zone and the last drilling day is the day drilling mud ceases to be circulated in the wellbore. The objective of the proposal was to more accurately calculate emissions using Calculation Method 2 by limiting the number of days multiplied by the emission factor to the days when mud is actually circulating in hydrocarbon-bearing zones when the potential for gas entrainment exists. If spudding is the standard for determination of the first day, this may add days to the emissions calculation when CH_4 is not actually entrained in the mud. Likewise, including days when the drill bore is retreating and mud is no longer circulating would include additional days in Calculation Method 2 when there is no potential for CH_4 to become entrained in the mud. Together these assumptions would overestimate emissions. Therefore, we are finalizing the definition of ''total number of drilling days'' as proposed except for the change that drilling days are further defined as the days when drilling mud is circulated in the wellbore.

Comment: Several commenters indicated that wells subject to reporting under this source are often wildcat or delineation wells, and, as such, should be subject to confidentiality or a delay in reporting.

Response: After further review, we agree with the commenters that many wells where drilling mud is used are exploratory wildcat or delineation wells. After consideration of this comment, we are finalizing the reporting requirements for Calculation Method 1 to provide a 2-year delay in

[34] See page 86 of 2011 *Oil and Gas Emission Inventory Enhancement Project for CenSARA States.* Produced by ENVIRON International Corporation for Central States Air Resources Agencies. November 2011. Available at *https://www.deq.ok.gov/wp-content/uploads/air-division/EI_OG_Final_Report_CenSara_122712.pdf* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

reporting certain data elements for all wells reported using Calculation Method 1 if the well is a wildcat or delineation well. Specifically, the Average concentration of natural gas in the drilling mud (X_n in equation W–41), in parts per million, the Measured mole fraction for CH_4 in natural gas entrained in the drilling mud (GHG_{CH4} in equation W–41), and the Total time that drilling mud is circulated in the well (T_r in equations W–41 and W–42 and Tp in equation W–43) are eligible for the 2-year delay for any well that is a wildcat and/or delineation well. In addition, the following data elements are eligible for the 2-year delay when one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42) is applied is a wildcat and/or delineation well: the Average mud rate (MR_r) and the Calculated CH_4 emissions rate ($ER_{sCH4,r}$). Reporting of the Total time that drilling mud is circulated in the well (Tr in equations W–41 and W–42) for the representative well may also be delayed for 2 years if one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42) is applied is a wildcat and/or delineation well. Wildcat and delineation wells are considered exploratory wells in the oil and gas industry, and data on these wells are generally considered sensitive information by the industry. State oil and gas commissions commonly hold such data from public release for two years. Therefore, the EPA has determined that these inputs to emission equations should be directly reported but are subject to a 2-year delay for exploratory wells to acknowledge the sensitive nature of the data and to ensure that the data cannot be back calculated prior to the end of the 2-year delay. However, we emphasize that this information would be considered to be emission data under CAA section 114 that is not eligible for confidential treatment upon submission to the agency, and thus will be made available to the public upon submission. Furthermore, emissions from any well with well degassing must still be reported annually and we further note that we have other information that will allow verification of reported emissions. Moreover, the EPA intends to be diligent in reviewing and reconciling delayed data with reported emissions data, and we also stress that, although the delayed data may not be reported in the initial reporting year, reporters must maintain records supporting their emission calculations and these records are subject to review by the EPA. Finally, the EPA intends to further evaluate whether this information will be required and, if so, may require reporting without delay in a future rulemaking.

Comment: Several commenters did not support the proposed requirement in 40 CFR 98.236(dd) to report certain data elements when using Calculation Method 1 to calculate emissions from mud degassing. Specifically, the commenters disagreed with reporting total vertical depth of the well and the circulation time of the drilling mud within the wellbore stating that the EPA did not address why the information would be requested. They further noted that in the case of total vertical depth, the reported data would not provide representative information for horizontal wells and would not improve the reported data quality.

Response: The EPA disagrees with the commenter that total vertical depth and mud circulation time should not be reported for Calculation Method 1 in 40 CFR 98.236(dd). Although formations dip and well to well correlations are sometimes subject to discontinuities, total vertical depth combined with identification of the stratigraphic formation provides a reasonable assurance that wells are drilled into the same hydrocarbon producing formations. Consistent with the change in Calculation Method 1 to apply the emissions rate from the representative well to other wells in the same sub-basin drilling in the same stratigraphic interval versus the same approximate depth, the EPA has added a reporting requirement to 40 CFR 98.236(dd) in the final rule to require reporters using Calculation Method 1 to also report the target hydrocarbon-bearing stratigraphic formation to which the well is drilled in addition to the total vertical depth. In response to the commenters' concerns about the requirement to report the total time that drilling mud is circulated in the well, this data element is necessary for the EPA to verify the reported CH_4 emissions using Calculation Method 1. Based on consideration of public comment and further research, however, we are finalizing that total time drilling mud is circulated in the well and other data elements in Calculation Method 1 are eligible for a 2-year delay for wildcat and delineation wells. See the response to the comment above for additional information.

5. Crankcase Venting

a. Summary of Final Amendments

The EPA is finalizing with revisions from proposal, as discussed further in this section, the addition of crankcase venting as a new emission source to be reported under 40 CFR 98.236(ee) by facilities in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import and Export Equipment, Natural Gas Distribution, and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. The EPA is finalizing with revisions from proposal, as discussed further in this section, methodologies for calculating emissions from crankcase venting under 40 CFR 98.233(ee). We are also finalizing as proposed revisions to 40 CFR 98.232 to include crankcase venting reporting requirements for the appropriate industry segments.

The EPA is finalizing with revisions from proposal the definition of crankcase venting under 40 CFR 98.238, with a clarification that an ingestive system may include, but is not limited to, closed crankcase ventilation systems and closed breather systems. We also are specifying in the revised definition that crankcase venting does not include vents where emissions are routed to another closed vent system, since these emissions are not released to the atmosphere. Further, following consideration of comments received, we are stating in the introductory paragraph of 40 CFR 98.233(ee) that crankcase venting emissions must only be calculated and reported for RICE with a rated heat capacity greater than 1 million British thermal units per hour (MMBtu/hr) (or the equivalent of 130 horsepower), which is consistent with the RICE combustion emissions reporting threshold under 40 CFR 98.236(z). We are also making revisions from proposal, after consideration of comments, to 40 CFR 98.233(ee) and 40 CFR 98.236(ee) to remove gas turbines from the final source types subject to crankcase venting emissions reporting.

Regarding revisions from proposal to the final methodologies for calculating emissions from crankcase venting under 40 CFR 98.233(ee), following consideration of comments received and consistent with section II.B. of this preamble, we are adding a direct measurement option for crankcase venting emissions as Calculation Method 1. Specifically, we are splitting the proposed 40 CFR 98.233(ee) into two paragraphs, with 40 CFR 98.233(ee)(1) for the added direct measurement option (final Calculation Method 1) and 40 CFR 98.233(ee)(2) for the final emission factor method (final Calculation Method 2, which we proposed under 40 CFR 98.233(ee), equation W–45) with modifications from proposal.

For the final Calculation Method 1 in 40 CFR 98.233(ee)(1), we are allowing the use of screening methods in 40 CFR 98.234(a) to determine whether quantitative emissions measurements are needed, similar to the rod packing methodologies for reciprocating compressors under 40 CFR 98.233(p). If emissions are detected using the screening methods, which for purposes of this calculation method are considered detected whenever a leak is detected according to the screening method used, direct measurement must be used to determine CH_4 emissions using the following technologies for conducting direct measurement of crankcase vent emissions: high volume samplers, meters (such as rotameters, turbine meters, hot wire anemometers, and others), or calibrated bags, in accordance with the methods in 40 CFR 98.234(b) through (d). If no emissions are detected during screening, then the reporter may assume that the volumetric emissions from the crankcase vent are zero. If a reporter elects to conduct screening and direct measurement of crankcase vents, all operating engines at the time of screening must then be screened at the facility, well-pad site, or gathering and boosting site at least once annually. Under the final Calculation Method 1, the reporter must then use equation W–45 under 40 CFR 98.233(ee)(1)(iv) to calculate the annual volumetric CH_4 emissions calculation for each RICE that was measured during the reporting year. We are also adding clarification to the final rule for reporters with crankcase vents tied into a manifolded group under 40 CFR 98.233(ee)(1)(iii). Under the final provisions for Calculation Method 1, if the manifolded group contains only crankcase vent sources, reporters must divide the measured volumetric flow equally between all operating RICE. Additionally, under the final provisions for this methodology, if the manifolded group contains crankcase vent sources and compressor vent sources, we assume that emissions are being characterized under 40 CFR 98.233(o) or (p) and should be reported under 40 CFR 98.236 (o) or (p), as applicable. We are also adding under 40 CFR 98.236(ee)(2) several reporting requirements for crankcase vent emissions calculated through direct measurement under 40 CFR 98.233(ee)(1), as well as a reporting requirement under 40 CFR 98.236(ee)(1)(v) for the count of reciprocating internal combustion engines with crankcase vents that were in a manifolded group containing a compressor vent source with emissions reported under 40 CFR 98.236(o) or (p).

We are also adding language in the final rule to instruct reporters who use Calculation Method 1 for calculating volumetric CH_4 emissions to use the procedures in 40 CFR 98.233(v) to calculate mass CH_4 emissions. This is standard language in all paragraphs of 40 CFR 98.233 for emission sources that require volumetric emission calculations. We are adding this language for consistency with the mass reporting requirements being finalized in 40 CFR 98.236(ee)(2)(ii).

For the final Calculation Method 2 in 40 CFR 98.233(ee)(2), including final equation W–46, this method provides a component-level average emission factor approach for estimating emissions for crankcase ventilation based on the number of RICE in the facility. The final provision have been modified from proposal to specify that this emission calculation should be performed for each RICE with a crankcase vent that is either not operating at the time of the direct emissions measurement conducted under 40 CFR 98.233(ee)(1), or at a facility, well-pad site, or gathering and boosting site where the reporter elects not to conduct direct emissions measurement on any engines. Correspondingly, this method is being modified from proposal to be performed per RICE. For example, where a reporter is using Calculation Method 2 for RICE with crankcase vents that are manifolded with other vents or equipment, equation W–46 should be performed for each RICE with a crankcase vent that is part of the manifold. As equation W–46 will be performed for each RICE, we are changing from proposal the requirement to report average estimated time that the RICE with crankcase venting were operational in the calendar year to instead require total time that each applicable RICE was operational during the calendar year. We are also changing from proposal the requirement to report the number of crankcase vents at the well-pad site, gathering and boosting site, or facility, to instead require reporting of the number of RICE with crankcase vents that operated at some point in the calendar year.

After consideration of comments received, the emission factor provided as part of final equation W–46 is being changed from units of standard cubic feet whole gas per hour per source to units of kilograms CH_4 per hour per source. We are also revising equation W–46 from proposal to include the unit conversion from kilograms CH_4 to metric tons CH_4 for consistency with the emissions reporting requirements of subpart W.

We are also adding language in the introductory paragraph of 40 CFR 98.233(ee) for the final rule that for reporters with crankcase vents routed to flares, the CO_2, CH_4 and N_2O emissions that result from combustion of the crankcase vent stream are reported as flare stack emissions under 40 CFR 98.236(n). The EPA is specifying that crankcase vents routed to a flare would follow the calculation requirements in 40 CFR 98.233(n) and would report flared crankcase emissions (CO_2, CH_4, and N_2O) separately from vented crankcase emissions (CH_4). We are finalizing requirements that flared emissions from crankcase vents are not required to be calculated and reported separately from other flared emissions. Instead, emission streams from crankcase vents 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. See section III.N. of this preamble for more information on the final flaring calculation and reporting provisions.

We are also finalizing requirements in 40 CFR 98.236(ee)(1) to report the total number of RICE with crankcase vents at the site (regardless of vent disposition), the number of these RICE that operated and were vented to the atmosphere for at least a portion of the year, and the number of these RICEs that operated and were routed to a flare for at least a portion of the year. We added a sentence at 40 CFR 98.233(ee) to further clarify these reporting requirements apply even when emissions from the crankcase vents are required to be reported under other sources (flares).

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add crankcase venting as an emission source for Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, LNG Import and Export Equipment, Natural Gas Distribution, and Onshore Petroleum and Natural Gas Gathering and Boosting facilities.

Comment: Many commenters noted that natural gas turbines do not have crankcase vents, or an equivalent emission source, and thus should be excluded from the crankcase venting emission source.

Response: The EPA agrees with the commenters that there was an inadvertent error in including natural gas turbines in the crankcase venting emission source category. We are finalizing a correction that will remove references to natural gas turbines from 40 CFR 98.233(ee) and 40 CFR 98.236(ee).

Comment: Several commenters requested the addition of a direct measurement option for crankcase vent methane emissions. The commenters stated that the IRA directs the EPA to include improved subpart W emission estimates by using empirical data, which they asserted is not addressed in the proposed crankcase venting. Commenters provided several different suggestions on how to incorporate direct measurement into the crankcase venting emission source.

Response: We agree with the commenters that a direct measurement option for the crankcase venting emission source could be appropriate and consistent with the directives of CAA section 136 if an appropriate direct measurement option could be identified. The EPA has considered all measurement options suggested by commenters, which included mimicking the measurement requirements of reciprocating and centrifugal compressors, allowing for site-specific emission factors, and/or allowing for emissions screening. At this time, we have determined that, consistent with the provisions for reciprocating compressor rod packing, a multi-step method for a direct measurement option is appropriate. Reporters may elect to complete emissions screening and then, if emissions from the crankcase vent are detected during screening, a measurement must be taken. If the reporter elects not to complete emissions screening, then all crankcase vents must be directly measured from engines operating at the time of the measurement event. Direct measurements must be taken at least annually on operating engines. We have also determined that at this time the most appropriate direct measurement methodologies for the crankcase venting emission source are provided in 40 CFR 98.234(b) through (d), which allow the use of an appropriate meter, calibrated bag, or high volume sampler. Regarding screening methods, we have determined that at this time any of the methods provided in 40 CFR 98.234(a) are appropriate for screening except for the acoustic leak detection method in 40 CFR 98.234(a)(5). The acoustic leak detection method is applicable only for through-valve leakage so it is not applicable to the crankcase vent. We have included this optional first step screening as an appropriate approach to reduce burden on those reporters with a significant quantity of crankcase vents while maintaining accuracy in total emissions. The EPA is not at this time allowing the option for reporters to develop site-specific emission factors because this methodology would require the specification of a minimum number of measurements that must be taken to be representative and new restrictions around these measurements, which should be proposed to allow comments.

Comment: Some commenters requested additional clarification on the definition of crankcase venting. Specifically, commenters requested that the EPA update the definition to clarify the term ''ingestive system,'' as it is more commonly referred to as a closed crankcase ventilation system or a closed breather system. Further, one commenter noted that as the EPA excludes crankcase vents that are returned to the combustion process from the crankcase venting definition, the EPA should consistently exclude crankcase vents that are routed to another closed vent system, as this would provide operators more flexibility.

Response: The EPA agrees with the commenters and has clarified the definition of crankcase venting in 40 CFR 98.238 of the final rule that an ingestive system may include, but is not limited to, closed crankcase ventilation systems and closed breather systems. Additionally, the EPA agrees that routing crankcase vent emissions to any closed vent system should allow the RICE to be excluded from reporting crankcase vent emissions and has therefore clarified this exemption in the crankcase venting definition.

Comment: Some commenters requested the ability to account for emission controls on crankcase vents. Commenters recommend adding this flexibility, which they state also has the added impact of incentivizing controls where feasible.

Response: The EPA agrees that reporters should be able to account for emission controls on crankcase vents. In the final rule, the EPA has added to the introductory paragraph of 40 CFR 98.233(ee) that flared emissions from crankcase vents should be calculated and reported according to 40 CFR 98.233(n) and 40 CFR 98.236(n), respectively. As stated above, the EPA has also excluded crankcase vents that route emissions to another closed vent system, such as a vapor recovery system, from the definition of crankcase venting. Also as noted above, the EPA has added a measurement option that will allow reporters to account for other emission controls on crankcase vents.

Comment: Several commenters noted that the parameter GHG_{CH4} in proposed equation W–45 incorrectly requires reporters to assume that the methane content of the crankcase vent stream is equivalent the methane content of the gas stream entering the RICE. They state that the crankcase vent stream can be diluted and may have a much lower methane content than the methane content of gas stream entering the RICE or the default value referenced. Commenters requested the ability to either measure the methane content of the crankcase gas vent, apply a scaling factor to the CH_4 content of the inlet gas, or use best available data to determine the GHG_{CH4} parameter.

Response: We agree that the use of the methane content in the gas stream entering the RICE would produce a conservative estimate of methane emissions from the crankcase vent. The emission factor upon which the proposed whole gas emission factor was based was in terms of THC but it is much more direct to convert this THC emission factor to methane. Thus, we are changing the emission factor proposed for Calculation Method 2, which was in terms of standard cubic feet of whole gas per hour, to use terms of kilograms CH_4 per hour. To do this, we reviewed the source of the proposed crankcase emission factor, the 2021 API Compendium.[35] API's emission factor, 2.28 standard cubic feet per hour per source, was developed from results from Phase II of a comprehensive measurement program conducted to determine cost-effective directed inspection and maintenance (DI&M) control opportunities for reducing natural gas losses due to fugitive equipment leaks and avoidable process inefficiencies. Phase II of the program was conducted at five gas processing plants, seven gathering compressor stations, and twelve well sites during 2004 and 2005.[36] This study, ''EPA

[35] *Compendium of Greenhouse Gas Emissions Methodologies For The Natural Gas And Oil Industry.* Produced by URS Corporation for American Petroleum Institute. November 2021. Available at *https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[36] *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* EPA Phase II Aggregate Site Report prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd.,

Phase II Aggregate Site Report: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, Technical Report,'' prepared by National Gas Machinery Laboratory, Clearstone Engineering, Ltd., and Innovative Environmental Solutions, Inc. (hereafter referred to as the ''Clearstone Phase II Study''), provided the crankcase emission factor as 0.12 kilograms of THC per hour per source, which API then converted to a whole gas factor.

In order to provide an emission factor in terms of kilograms of CH_4 per hour per source for use in the equation W–46, the EPA started with the Clearstone Phase II study's THC emission factor. We expect the THC in the crankcase vent originates from either direct natural gas leaks into the crankcase or uncombusted hydrocarbons in exhaust gas that leaks into the crankcase. In either event, we expect the ratio of methane to THC in the crankcase vent to be represented by the average ratio of methane to THC in the natural gas used as fuel for the engine. We used the average methane-to-total organic compounds (TOC) weight ratios for production of 0.695 and transmission of 0.908 used in estimating emission impacts for the NSPS OOOOb rule (see Docket ID. No. EPA–HQ–OAR–2021–0317–1578, attachments 4 through 6, tab ''Composition and Factors''). Using these factors, the EPA converted the Clearstone Phase II study THC emission factor from units of kilograms THC per hour per source to units of kilograms CH_4 per hour per source.[37] The emission factors provided in equation W–46 of the final rule are 0.083 kg CH_4/hr/engine for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities and 0.11 kg CH_4/hr/engine for all other applicable industry segments. We are also revising equation W–46 to include the unit conversion from kilograms CH_4 to mt CH_4 for consistency with the emissions reporting requirements of subpart W.

Comment: One commenter was concerned that engine size was not considered in calculating emissions or developing the emission factor used in proposed equation W–45. The commenter states that gas storage compressors and compressor station engines on which the proposed emission factor is based are of a much larger scale than production facility engines and are therefore expected to have a much higher vent rate. The commenter requested a de-minimis exemption for very small engines, or the allowance of direct measurement of crankcase vents.

Response: The EPA is finalizing the option for direct measurement of crankcase gas vent emissions, as previously discussed. In an effort to be consistent with the provisions of 40 CFR 98.233(z), the EPA is changing the language in the introductory paragraph of 40 CFR 98.233(ee) to state that only RICE with a rated heat capacity greater than 1 MMBtu/hr (or the equivalent of 130 horsepower) must calculate emissions from crankcase venting. We may consider evaluating the removal of this exclusion in future rulemakings.

Comment: Several commenters opposed the emission factor methodology, which was proposed on a per vent approach. Commenters requested that the emission factor be per RICE, rather than per crankcase vent, to avoid confusion. One commenter also noted that the proposed emission factor of 2.28 scfh per vent is not consistent with crankcase emissions per engine based on the study, ''Characterization of Crankcase Ventilation Gas on Stationary Natural Gas Engines,'' by Colorado State University (March 2023). One commenter further stated that the reporting requirements under 40 CFR 98.236(ee) should be on a per-site basis.

Additionally, some commenters requested clarification on the term ''vent'' in proposed equation W–45. Commenters noted that vents can be manifolded together. Commenters stated that, for example, when installed within a structure, crankcase vents from multiple engines are typically routed to a central manifold and exhausts to the exterior of the structure through a single ''vent.'' The commenters stated that the proposed rule could be interpreted as allowing the 2.28 scfh per vent emission factor to apply to the manifolded vent rather than each individual engine's vent.

Response: The EPA has reviewed the source of the proposed emission factor, the Clearstone Phase II Study, and confirmed that the emission factor provided in the study is in units of kilograms THC per hour per crankcase vent, but additional detail on the measurement locations and vent configurations is not provided in the study. However, the EPA agrees with the commenters that the methodology would be more clear if the factor was presented on a per RICE basis, especially for crankcase vents that are manifolded together. Based on a technical drawing included in the Clearstone Phase II Study, the EPA assumes that the Clearstone Phase II Study emission factor was likely representative of crankcase vent emissions from the whole engine. Therefore, we have revised the emission factor methodology and equation W–46 to be per RICE in the final rule. Further, we have provided a calculation methodology for reporters who elect to directly measure emissions from a manifolded vent; under the final provisions for this methodology, if the manifolded group contains only crankcase vent sources, reporters must divide the measured volumetric flow equally between all operating RICE. Additionally, under the final provisions for this methodology, if the manifolded group contains crankcase vent sources and compressor vent sources, the measurement made when the compressor is in operating mode must be included in the emissions being characterized under 40 CFR 98.233(o) or (p) and must be reported under 40 CFR 98.236 (o) or (p), as applicable. Therefore, we are not requiring facilities that manifold their crankcase vent with compressor vent sources to separately characterize their crankcase vent emissions, because that would double-count these emissions. This approach is consistent with the goal of CAA section 136(h) to develop accurate facility-wide methane emissions.

Further, the EPA has reviewed the study, ''Characterization of Crankcase Ventilation Gas on Stationary Natural Gas Engines,'' by Colorado State University (March 2023) (hereafter referred to as the ''2023 CSU Study'') and determined that the data is not appropriate for use in the final rule. We have determined that the 2023 CSU study is too limited to establish national average CH_4 concentration values. The study team studied one four-stroke lean-burn engine in the field and lab-tested two additional engines (one four-stroke rich-burn and one two-stroke lean-burn). The field-tested engine was at tested at 85 percent load, while the lab-tested engines were measured at several different loads. The study sampled and characterized the crankcase gas on the natural gas engines with the end goal of installing a closed crankcase recirculation/filtration system. The field testing on the four-stroke lean-burn engine found that CH_4 accounts for 3.6

and Innovative Environmental Solutions, Inc. March 2006. Available at *https://www.epa.gov/sites/default/files/2016–08/documents/clearstone_ii_03_2006.pdf* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[37] 0.694769294934942 kg CH_4/kg TOC for production facilities; 0.907710347197016 kg CH_4/kg TOC for transmission facilities. It was assumed that TOC = THC for the purposes of this conversion and that all THC in the crankcase gas is from uncombusted fuel gas.

percent of the crankcase gas. The lab testing on the four-stroke rich-burn engine found higher levels of CH_4 in the crankcase gas at 5.5 percent by volume, and the two-stroke lean-burn engine had very low levels of CH_4 in the crankcase gas (0.3 percent by volume). However, the study did not determine a CH_4 emission rate. Additionally, the 2023 CSU study only tested CH_4 concentrations in the crankcase gas for three engines, two of which were in controlled conditions of a laboratory setting. The EPA has determined that the results of this study are not representative of the industry as a whole due to the low sample size.

In response to the commenter's request to report data for crankcase venting on a per-site basis, the EPA notes that the data reported under 40 CFR 98.236(ee)(2) of the final rule would be aggregated at the facility, well-pad site, or gathering and boosting site level. Given the detailed reporting requirements for facilities electing to use Calculation Method 1, direct measurement data collected under 40 CFR 98.236(ee)(1) of the final rule is required to be reported for each test performed on an operating RICE. However, to alleviate burden, the EPA has revised requirements under 40 CFR 98.236(ee)(2) in the final rule that would remove averaging of data at the site level. In the final rule, we have revised the requirement under 40 CFR 98.236(ee)(2)(iii) from reporting of average operating hours to reporting of total operating hours of RICE with crankcase vents.

D. Reporting for the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Industry Segments

1. Summary of Final Amendments

As explained in the 2023 Subpart W proposal, the current sub-basin or basin-level aggregation of data reported within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting segments can present challenges in the process of emissions verification, with corresponding potential impacts on data quality. The EPA proposed several amendments to reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. Consistent with section II.C. of this preamble, the EPA is finalizing these amendments as proposed, with the exception that certain instances of the term ''well-pad'' have been updated to ''well-pad site'' in the final amendments. We are finalizing an additional clarifying amendment at 40 CFR 98.236(aa)(10)(v) related to which gathering and boosting sites must be reported and adding a new definition for the term ''well-pad site'' at 40 CFR 98.238. These clarifying amendments are discussed later in this section. As a first step, the EPA is finalizing as proposed the reporting requirements to be more explicitly consistent with the reporting form structure for the well identification (ID) numbers at the facility as discussed in detail in the 2023 Subpart W Proposal. The EPA is finalizing as proposed revisions to 40 CFR 98.236(aa)(1)(ii) and additional well-specific reporting requirements in 40 CFR 98.236(aa)(1)(iii). Additionally, the EPA is no longer requiring the sub-basin ID to be reported for each well. Instead, reporters will report the sub-basin ID by well-pad and then report the well-pad ID on which the well is located. The well-pad ID is a new data element and is described in the following paragraph. The EPA is also finalizing as proposed the revisions to the requirements to provide a list of well IDs for the five emission source types directly related to wells to instead specify that reporters must report emissions and activity data for each of those emission source types by well within the source-specific reporting requirements, as described later in this section.

Second, the EPA is adding as proposed the following data elements: well-pad ID (for Onshore Petroleum and Natural Gas Production segment) and gathering and boosting site ID (for Onshore Petroleum and Natural Gas Gathering and Boosting). These data elements are hereafter collectively referred to as ''site-level IDs.'' The EPA is adding to 40 CFR 98.236(aa)(1)(iv) (for Onshore Petroleum and Natural Gas Production) and 40 CFR 98.236(aa)(10)(v) (for Onshore Petroleum and Natural Gas Gathering and Boosting) requirements for reporting of information related to each well-pad ID and gathering and boosting site ID, respectively. The reporting elements for each well-pad ID include a unique name or ID for each well-pad, the sub-basin ID, and the location (*i.e.,* representative latitude and longitude coordinates).

To clarify requirements related to the final well-pad ID data element, the EPA is finalizing a definition for the newly defined term well-pad site. The term is defined to mean all equipment on or associated with a single well-pad. Specifically, the well-pad site includes all equipment on a single well-pad plus all equipment associated with that single well-pad. This definition was added to clarify and align the term ''well-pad site'' with the existing definition of a facility with respect to the Onshore Petroleum and Natural Gas Production industry segment, which is not being updated as part of this rulemaking. The EPA understands that certain equipment at facilities within the Onshore Petroleum and Natural Gas Production segment may not be present directly on a well-pad, such as an off-well-pad tank battery that is associated with a single well-pad. The final definition clarifies that such equipment would be considered part of the well-pad site for emission calculation and reporting purposes. Further discussion of this definition as it applies to specific emission sources can be found in sections III.E.1. (with respect to pneumatic devices) and III.P. (with respect to equipment leaks) of this preamble. Related to this new definition, where the 2023 Subpart W Proposal used the term ''well-pad'' to describe the level of aggregation for reporting, we are finalizing the associated provisions to instead use the term ''well-pad site.''

For the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, the EPA is finalizing requirements as proposed at 40 CFR 98.236(aa)(10)(v) to require reporters to provide a unique name or ID, the site type, and the location for each gathering and boosting site. After consideration of public comment, the EPA is finalizing 40 CFR 98.236(aa)(10)(v) with clarifying language that reporting is only required for gathering and boosting sites for which there were emissions in the calendar year. This is consistent with the intent of the 2023 Subpart W proposed language, as requiring reporting for sites without emissions would not benefit the process of emissions verification or improve data quality and data transparency. For the ''site type'' for each gathering and boosting site, reporters will select between ''gathering compressor station,'' ''centralized oil production site,'' ''gathering pipeline site,'' or ''other fence-line site.'' The EPA is finalizing a definition of ''gathering compressor station'' in 40 CFR 98.238 to be used for the purposes of this reporting requirement and to differentiate gathering compressor stations from other types of compressor stations in subpart W (*e.g.*, transmission compressor stations). The Onshore Petroleum and Natural Gas Gathering and Boosting industry segment also includes centralized oil production sites that collect oil from multiple well-pads but that do not have compressors (*i.e.,* are not ''compressor stations''). The EPA is finalizing a definition of a ''centralized oil production site'' in 40 CFR 98.238 to be used for the purposes of this reporting requirement. For gathering pipelines, the EPA is finalizing a definition of ''gathering pipeline site'' to specify that it is all the gathering pipelines at the facility within a single state. In previous rulemakings, the EPA has received information from stakeholders noting that there are facility configurations that would not clearly fit within the proposed definition for ''gathering compressor station'' or ''centralized oil production site,'' including, but not limited to, booster stations, dehydration facilities, and treating facilities.[38] The EPA is finalizing as proposed the ''other fence-line site'' site type to cover these types of sites. For gathering pipelines, the EPA is including within the definition of ''gathering and boosting site'' that a gathering pipeline site is all the gathering pipelines at the facility within a single state. For the ''location'' reported for each gathering and boosting site, the EPA is requiring that reporters will provide the representative latitude and longitude coordinates where the site type is a gathering compressor station, centralized oil production site or other fence-line facility, and the state where the site type is a gathering pipeline.

For the emission source types in the Onshore Petroleum and Natural Gas Production industry segment directly related to wells that currently report by sub-basin (*i.e.,* well venting for liquids unloading, completions and workovers with hydraulic fracturing, completions and workovers without hydraulic fracturing, and associated gas venting or flaring) or by calculation method and use of a flare (*i.e.,* well testing), we are finalizing amendments to require reporting of emissions and activity data for each individual well instead of in the prior aggregations (*e.g.,* by sub-basin). Where the prior emission source-level provisions of 40 CFR 98.236 for the Onshore Petroleum and Natural Gas Production industry segment and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment required reporting at either the facility or the sub-basin level (other than the emission source types directly related to wells), the final amendments no longer require reporting at the sub-basin level and instead require reporters to provide emissions and activity data by well-pad ID or gathering and boosting site ID for each facility. For emission source types that report at the unit level (*e.g.*, AGRs, dehydrators, and flares), there is no change to the reporting level but reporters are required to identify the well-pad ID or gathering and boosting site ID. This requirement replaces reporting of the county or sub-basin ID, if applicable.

Due to the change of the level of aggregation of activity data to the well level or well-pad site level within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum industry segment, the EPA is also finalizing changes to the data elements for which reporters with wildcat wells and/or delineation wells may delay reporting for 2 years. Wildcat and delineation wells are considered exploratory wells in the oil and gas industry, and data from these wells are generally considered sensitive information by the industry. State oil and gas commissions commonly hold such data from public release for two years. Based on consideration of public comments, we are finalizing provisions allowing reporters to delay reporting of the following inputs to emission equations for wildcat wells and/or delineation wells for 2 years to acknowledge the sensitive nature of the data and to ensure that the data cannot be back calculated prior to the end of the 2-year delay.[39]

For completions and workovers with hydraulic fracturing, if the well is a wildcat well or delineation well:

- 40 CFR 98.236(g)(5)(i)—Cumulative gas flowback time, in hours, for all completions or workovers at the well from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation.
- 40 CFR 98.236(g)(5)(ii)—If the well is a measured well for the sub-basin and well-type combination, the flowback rate, in standard cubic feet per hour.
- 40 CFR 98.236(g)(5)(iii)(A)—If you used equation W–12C, gas to oil ratio for the well in standard cubic feet of gas per barrel of oil.
- 40 CFR 98.236(g)(5)(iii)(B)—If you used equation W–12C, volume of oil produced during the first 30 days of production after completions of each the newly drilled well or well workover using hydraulic fracturing.

For completions and workovers without hydraulic fracturing, if the well is a wildcat well or delineation well:

- 40 CFR 98.236(h)(1)(iii)—For a well with one or more gas well completions without hydraulic fracturing and without flaring, total number of hours that gas vented directly to the atmosphere during venting for all completions in the sub-basin category without hydraulic fracturing.
- 40 CFR 98.236(h)(1)(iv)—For a well with one or more gas well completions without hydraulic fracturing and without flaring, average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring.
- 40 CFR 98.236(h)(2)(iii)—For a well with one or more gas well completions without hydraulic fracturing and with flaring, total number of hours that gas routed to a flare during venting for all completions without hydraulic fracturing.
- 40 CFR 98.236(h)(2)(iv)—For a well with one or more gas well completions without hydraulic fracturing and with flaring, average daily gas production rate for all completions without hydraulic fracturing with flaring.

For well testing, if the well is a wildcat well or delineation well:

- 40 CFR 98.236(l)(1)(iv)—For an oil well not routed to a flare, average gas to oil ratio for the tested well.
- 40 CFR 98.236(l)(1)(iv)—For an oil well not routed to a flare, average gas to oil ratio for the tested well.
- 40 CFR 98.236(l)(1)(v)—For an oil well not routed to a flare, average flow rate for the tested well.
- 40 CFR 98.236(l)(2)(iv)—For an oil well routed to a flare, average gas to oil ratio for the tested well.
- 40 CFR 98.236(l)(2)(v)—For an oil well routed to a flare, average flow rate for the tested well.
- 40 CFR 98.236(l)(3)(iii)—For a gas well not routed to a flare, number of well testing days for the tested well in the calendar year.
- 40 CFR 98.236(l)(3)(iv)—For a gas well not routed to a flare, average annual production rate for the tested well.
- 40 CFR 98.236(l)(4)(iii)—For a gas well routed to a flare, number of well testing days for the tested well in the calendar year.
- 40 CFR 98.236(l)(4)(iv)—For a gas well routed to a flare, average annual production rate for the tested well.

For associated gas venting and flaring, if the well is a wildcat well or delineation well:

[38] Letter from Angie Burckhalter, The Petroleum Alliance of Oklahoma, to Administrator Michael S. Regan, U.S. EPA, Re: Docket ID. No. EPA–HQ–OAR–2019–0424; Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule. October 6, 2022. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[39] See section III.C.4. of this preamble for a description of the provisions for delayed reporting of inputs to emission equations for mud degassing wildcat wells and/or delineation wells.

• 40 CFR 98.236(m)(5)—Volume of oil produced by the well in the calendar year only during the time periods in which associated gas was vented or flared.

• 40 CFR 98.236(m)(6)—Total volume of associated gas sent to sales or used on site and not sent to a vent or flare in the calendar year only during time periods in which associated gas was vented or flared.

Reporters are not allowed to delay reporting of any of the emissions from these sources, nor are they allowed to delay reporting of any other data elements in 40 CFR 98.236. Providing a 2-year delay in reporting for these specific inputs protects sensitive information during the time in which it is considered to be sensitive information by the industry. After 2 years have passed, reporters will be required to report these inputs to emission equations. We emphasize that this information would be considered to be emission data under CAA section 114 that is not eligible for confidential treatment upon submission to the agency, and thus will be made available to the public upon submission. Furthermore, emissions from any well with well degassing must still be reported annually and we further note that we have other information that will allow verification of reported emissions. Moreover, the EPA intends to be diligent in reviewing and reconciling delayed data with reported emissions data, and we also stress that, although the delayed data may not be reported in the initial reporting year, reporters must maintain records supporting their emission calculations and these records are subject to review by the EPA. Finally, the EPA intends to further evaluate whether this information will be required and, if so, may require reporting without delay in a future rulemaking.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments.

Comment: The EPA received several comments asserting that the EPA has not presented a clear rationale rooted in the EPA's statutory authority for the proposed requirement to disaggregate current reporting levels in the Onshore Production and Onshore Gathering and Boosting industry segments.

Response: With the exception of a clarifying amendment to 40 CFR 98.236(aa)(10)(v) discussed elsewhere in this section, the EPA is finalizing the amendments affecting the aggregation of data reported within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments as proposed.

As stated in section III.D. of the preamble to the 2023 Subpart W Proposal, the aggregation of data currently collected for these industry segments ''can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency.'' Prior to the amendments finalized in this rulemaking, emissions and activity data for certain emission sources in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments were reported at the basin or county/sub-basin level. Sources that previously reported at the facility (basin) level include natural gas pneumatic devices, blowdown vent stacks, and equipment leaks. Emission sources that reported at the sub-basin or county level included liquids unloading, completions and workovers with hydraulic fracturing, and storage tanks. This level of aggregation can cover a wide geographic area and include numerous well-pads or gathering and boosting sites. As a result, certain methods of emissions verification are not possible or limited in utility for these sources. For example, a verification review looking at data reported year-over-year for an individual gathering and boosting site may be able to identify data entry errors (e.g., a decimal point entered at the wrong order of magnitude) that would be masked at higher levels of aggregation. Identification of similar types of errors for sources not aggregated at this level regularly occurs during the EPA verification process and has resulted in significant changes (both increases and decreases) to reported emissions.

The directive under CAA section 136(h) to ensure that reporting under subpart W accurately reflects total methane emissions is inexorably linked to verification of reported data. Absent a robust system of emissions verification, the EPA cannot ensure the accuracy of reported data. As such, the proposed amendments to improve the quality and verification of subpart W data are supportive of the directive of CAA section 136(h). Further, as discussed in section II.C. of the preamble to the 2023 Subpart W Proposal, beyond carrying out the requirements of CAA section 136, the data collected under subpart W is used to support a range of policies and initiatives under the CAA including but not limited to ''provisions involving research, evaluating and setting standards, endangerment determinations, or informing EPA non-regulatory programs.'' The final amendments affecting the aggregation of data reported within the Onshore Petroleum and Natural Gas Production reporting requirements are expected to further the EPA's understanding of the industry for future purposes of carrying out provisions under the CAA.

One commenter asserted that changes in the aggregation of reported data would not impact the total emissions reported under subpart W. The EPA notes that the intent of the amendments to the aggregation of data for these industry segments is not to increase or decrease overall emissions reported, but to support the verification of reported data and provide a higher degree of data quality and transparency to ensure accuracy of total emissions reported, and that such verification may identify errors that would have resulted in either over- or under- statement of emissions. Further, the EPA anticipates that preparation of more granular reports may provide reporters the opportunity to identify errors that would have resulted in over- (or under-) statement of emissions. We also expect that for facilities subject to the waste emission charge under CAA section 136, that facilities will want to review their data at a more granular level, to ensure that any charges are accurate.

In addition to improving the quality and transparency of data collected under subpart W, the amendments affecting the aggregation of data reported within the Onshore Petroleum and Natural Gas Production will support the EPA's implementation of the WEC under CAA section 136. For example, CAA section 136(f)(7) requires that, ''[c]harges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements, as determined by the Administrator.'' Prior to the amendments finalized in this rulemaking, emissions from liquids unloading, workovers with hydraulic fracturing, and workovers without hydraulic fracturing were reported by sub-basin and emissions from leaks associated with the wellhead were reported at the facility (basin) level. This level of aggregation is not compatible with being able to determine the ''emissions rate from any well'' as required by CAA section 136(f)(7). Following these amendments, data for leaks associated with a wellhead will be reported at the well-pad site level while liquids unloading and workovers will be reported by well ID, which can be associated directly with a well that has been permanently shut-in and plugged.

Additionally, the EPA notes that existing subpart W requirements specify calculation of emissions at the well level for certain sources, including Well Venting for Liquids Unloading, Completions and Workovers with Hydraulic Fracturing, Completions and Workovers without Hydraulic Fracturing, Well Testing and Associated Gas. The EPA is not changing the level at which these calculations are required to be performed, just the level at which they are reported. It is also noted that certain other sources including flare stacks, AGRs, and enhanced oil recovery (EOR) pumps are already reported at the unit level. The EPA does not anticipate significant burden related to the change in aggregation of reported data for these sources.

Comment: One commenter stated that the proposed reporting requirement for ''each gathering and boosting site located in the facility'' at 40 CFR 98.236(aa)(10)(v) was unclear as to whether reporters are required to report information for sites that are shutdown, bypassed, or otherwise have no potential for emissions.

Response: The intent of the referenced reporting requirement is to collect information only for gathering and boosting sites that were operational during the calendar year. For further clarification, 40 CFR 98.236(aa)(10)(v) has been amended to specify that reporting is only required for sites for which there were emissions in the calendar year.

Comment: One commenter noted that where reporting would be required by well or by well-pad, the EPA did not propose to change the language for wildcat and delineation wells that specified that reporters may delay reporting certain data elements for 2 years ''if the only wells in the sub-basin are wildcat and delineation wells.'' The commenter questioned why the EPA did not provide a delay in reporting for single wildcat and delineation wells, for emission sources that must be reported by well, or provide a delay in reporting if the only wells on the well-pad are wildcat and delineation wells, for emission sources that must be reported by well-pad. Finally, the commenter asked whether the use of ''and/or'' in any provisions referring to a single well is a typo or if a single well can be both a wildcat and delineation well.

Response: For the existing emission sources that will be required to report emissions and activity data by well or by well-pad site, the EPA reviewed the provisions for specific inputs to emissions equations for which we currently provide or proposed to provide the ability for reporters to choose to delay reporting for wildcat and delineation wells for 2 years to protect sensitive information. As documented in the September 23, 2015 memorandum ''Review for Potential Disclosure Concerns for Inputs to Emission Equations Affected by the ''2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems,'' the EPA determined that certain inputs to emission equations would not be likely to reveal any sensitive information, except for two specific types of exploratory wells, delineation wells and wildcat wells. Information specific to exploratory wells is generally considered sensitive information by the industry, so the EPA determined that these inputs to an emission equation should be directly reported but that reporters may delay reporting of sensitive information. The proposal, consistent with the prior reporting requirements as described in that memorandum, acknowledged the sensitive nature of certain data for exploratory wells.

The following paragraphs describe our review for specific source types for which we determined that changes from proposal for the 2-year delay provisions were appropriate. For all source types, we emphasize that all other data, including natural gas emissions, emissions of CH_4 and CO2, and activity data for which a 2-year delay is not explicitly provided, must be reported in the applicable reporting year. The EPA will be very diligent in reviewing current year and delayed data to verify that emissions originally reported are accurate. In addition, for each of these source types, we note that wildcat and delineation wells are slightly different types of wells, and a single well would not be considered both a wildcat well and a delineation well. Therefore, for source types for which emissions and activity data must be reported by well in the final rule, the provisions for delay of reporting refer to ''a wildcat or delineation well.'' Provisions that allow a delay in reporting only all the wells at the well-pad site, sub-basin, or facility are wildcat wells, delineation wells, or some of each refer to ''wildcat wells and/or delineation wells.''

Completions and workovers with hydraulic fracturing. The proposal provided a 2-year delay for the reporting of certain data elements for wildcat and/or delineation wells, but only when all wells with completions and workovers with hydraulic fracturing in the same sub-basin and well-type combination were wildcat and/or delineation wells. The specific data elements included the cumulative amount of time flowback during the initial and separation flowback stages, $T_{p,s}$ and $T_{p,i}$ respectively, and the average gas flowback rate at the beginning of the separation stage ($FR_{s,p}$) when using equation W–10A, as well as the for the gas to oil ratio (GOR), GORp, and the volume of oil produced during the first 30 days of production (V_p) when using equation W–12C to calculate a 30-day gas production rate for oil wells when using equation W–10A. However, under the final rule, emissions and associated data elements will be reported at the well level; therefore, publication of the data elements specified above even when not all wells in the sub-basin are wildcat or delineation wells may reveal sensitive information. Therefore, we are finalizing the reporting requirements for completions and workovers with hydraulic fracturing to continue providing the option for the 2-year delay in reporting these data elements but we are no longer requiring that all wells in the sub-basin be wildcat and/or delineation wells for reporters to be able to use the 2-year delay.

Completions and workovers without hydraulic fracturing. The proposal provided a 2-year delay for the reporting of certain data elements for wildcat and/ or delineation wells, but only when all wells with completions and workovers without hydraulic fracturing in the same sub-basin and well-type combination were wildcat and/or delineation wells. The specific data elements included the average daily gas production required by 40 CFR 98.236(h)(1)(iv) and (h)(2)(iv). However, under the final rule, emissions will be reported at the well level; therefore, publication of this information even when not all wells in the sub-basin are wildcat or delineation wells may reveal sensitive information. Therefore, we are finalizing the reporting requirements for completions and workovers without hydraulic fracturing to continue providing the option for the 2-year delay in reporting these data elements, but we are no longer requiring that all wells in the sub-basin be wildcat and/or delineation wells for reporters to be able to use the 2-year delay. In addition, we are allowing reporters the option of a 2-year delay in reporting the total number of hours that gas is vented or flared, 40 CFR 98.236(h)(1)(iii) or (h)(2)(iii). Equation W–13B computes the quantity of natural gas emissions by multiplying the average daily gas production rate by the number of hours gas is vented or routed to a flare. Under the proposed rule, reporters would have been required to report without a delay the natural gas emissions and the total hours that gas is vented or routed to a flare, but this would have allowed back-calculation of the production rate at the well level.

Well testing. The proposal provided a 2-year delay for the reporting of certain data elements for wildcat and/or delineation wells, but only when all wells tested in the same sub-basin were wildcat and/or delineation wells. The specific data elements included the average flow rate in equation W–17A for oil wells and the average annual production rate for gas wells in equation W–17B. However, under the final rule, emissions and associated data elements will be reported at the well level and publication of the data elements discussed above even when not all wells in the sub-basin are wildcat or delineation wells may reveal sensitive information. Therefore, we are finalizing the reporting requirements for well testing to continue providing the option for the 2-year delay in reporting these data elements, but we are no longer requiring that all wells in the sub-basin be wildcat and/or delineation wells for reporters to be able to use the 2-year delay. In addition, for oil wells, we are allowing reporters the option of a 2-year delay in reporting the average GOR for the well in equation W–17A in the final rule, and for gas wells, we are allowing reporters the option of a 2-year delay in reporting the number of well testing days in equation W–17B in the final rule. Reporters use equation W–17A to calculate natural gas emissions from oil wells by multiplying the GOR by the flow rate in barrels of oil per day by the number of days wells are tested. The proposal only provided a 2-year delay for the flow rate. Reporting of all other data elements would allow back calculation of the flow rate; therefore, the EPA is finalizing the rule today to provide the 2-year reporting delay for average GOR. Equation W–17B computes the quantity of natural gas emissions by multiplying the average annual gas production rate by the number of days. Under the proposed rule, reporters would have been required to report without a delay the natural gas emissions and the total number of days, which would have allowed back-calculation of the production rate.

Associated natural gas. The proposal provided a 2-year delay for the reporting of certain data elements for wildcat and/or delineation wells, but only when all wells with associated natural gas in the same sub-basin were wildcat and/or delineation wells. The specific data elements included the volume of oil produced and the volume of associated gas sent to sales in 40 CFR 98.236(m)(5) and(6) when using equation W–18. However, under the final rule, associated gas emissions and related data will be reported at the well level and publication of certain data related to associated gas venting and flaring even when not all wells in the sub-basin are wildcat or delineation wells may reveal sensitive information. Therefore, we are finalizing the reporting requirements for associated gas to continue providing the option for the 2-year delay for volume of oil produced and volume of gas sent to sales but we are no longer requiring that all associated gas wells in the sub-basin be wildcat and/or delineation wells for reporters to be able to use the 2-year delay.

Comment: Multiple commenters disagreed with the proposed definition of a ''centralized oil production site'' and its proposed designation as a site type for facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. Commenters requested that the term ''centralized oil production site'' be revised to ''centralized production facility,'' the associated definition be revised to match the definition of the term in the NSPS OOOOb and EG OOOOc regulations, and that the site type be designated as part of the Onshore Petroleum and Natural Gas Production industry segment. Commenters asserted that the proposed definition and placement within the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment were inconsistent with CAA section 136.

Response: The EPA is finalizing the definition of ''centralized oil production site'' as proposed. The EPA notes that the EPA did not reopen, and no change was proposed nor is being finalized in this rulemaking to, the industry segment definitions for ''Onshore petroleum and natural gas production'' and ''Onshore petroleum and natural gas gathering and boosting'' at 40 CFR 98.230(a)(2) and (9), respectively, nor the definitions of facilities with respect to this industry segment in 40 CFR 98.238. The EPA is finalizing one minor revision to the industry segment definition for ''Onshore petroleum and natural gas gathering and boosting'' in this rulemaking, at 40 CFR 98.230(a)(9), to clarify the EPA's original intent that the petroleum and/or natural gas is transported to a downstream endpoint, as is already clear from the definition of ''gathering and boosting system'' in 40 CFR 98.238 (see section III.U.3. of this preamble for additional information). However, this revision does not substantively change the industry segment definition. The EPA did not reopen, and no change was proposed nor is being finalized in this rulemaking to, the definition of facility with respect to this industry segment in 40 CFR 98.238. The new reporting element of a site type (including the newly defined centralized oil production site) for facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment does not change the applicable industry segment for reporting facilities, either before or after this rulemaking comes into effect. In other words, existing sites that meet the new ''centralized oil production site'' definition are currently considered to be part of the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment and will continue to be considered part of this segment with this final rule. The distinction between an Onshore Petroleum and Natural Gas Production facility and an Onshore Petroleum and Natural Gas Gathering and Boosting facility under the existing and finalized subpart W is primarily based on whether the equipment is located on a single well-pad or associated with a single well-pad (onshore production equipment) or located off a single well-pad and associated with two or more single well-pads (gathering and boosting equipment). Centralized oil production sites are distinct from the separately defined well-pad sites and receive hydrocarbon liquids from two or more single well-pads. Therefore, these sites do not meet the criteria for inclusion in an Onshore Petroleum and Natural Gas Production facility as defined in subpart W.

Although implementation of CAA section 136(c) (''Waste Emissions Charge'') is outside the scope of this rulemaking, the EPA notes that CAA section 136(d) defines the term ''applicable facility'' as a facility within specified industry segments as defined in subpart W. Thus, this approach is consistent with the existing facility definitions in subpart W referenced in CAA section 136 when the statutory provision was enacted. As previously noted, the EPA did not propose and is not finalizing changes to the definition of the ''Onshore petroleum and natural gas gathering and boosting'' industry segment (beyond the minor clarification noted in the previous paragraph) or the definition of a facility with respect to this segment, and as such the request to change this definition is outside the scope of this rulemaking.

E. Natural Gas Pneumatic Device Venting and Natural Gas Driven Pneumatic Pump Venting

Subpart W currently requires calculation of GHG emissions from natural gas pneumatic device venting (existing 40 CFR 98.233(a)) and natural gas driven pneumatic pump venting (existing 40 CFR 98.233(c)) 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). In our 2022 Proposed Rule, we proposed to update the population emission factors for pneumatic devices based on recent study data. In the 2023 Subpart W Proposal, we proposed adding calculation methods based on measurements and leak screening for all pneumatic device types while retaining the option to use population emission factors for continuous bleed pneumatic devices only. For intermittent bleed pneumatic devices, the 2023 Subpart W Proposal removed the option to use default population emission factors allowing only measurement and leak screening methods to be used. In this final rule, after consideration of the comments received, we are finalizing measurement options similar to those included in the 2023 Subpart W Proposal, updating from proposal to allow facilities the option to use population emission factors for all pneumatic device types (including intermittent bleed devices), and updating the default population emission factors for all pneumatic device types (including intermittent bleed devices) as proposed in the 2022 Proposed Rule and consistent with request for comments on this approach included in the 2023 Subpart W Proposal. Therefore, in the final rule, up to four calculation methods are provided as described in this section.

As proposed, we are expanding the number of industry segments that have to report natural gas pneumatic device venting to include Onshore Natural Gas Processing and Natural Gas Distribution industry segments. However, we are not finalizing the first portion of the first sentence that was proposed at 40 CFR 98.233(a) listing all of the industry segments that must calculate pneumatic device venting emissions. Listing these industry segments in 40 CFR 98.233(a) is duplicative of the information in 40 CFR 98.232 and inconsistent with how the calculation methods for other emission sources are stated. Similarly, we are deleting the listing of industry segments in the definition of GHGi term in equation W–1B. We are also adding a sentence to 40 CFR 98.233(a) to clarify that references to natural gas pneumatic devices for Calculation Method 1 also apply to combinations of natural gas pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line, consistent with the corresponding provisions in 40 CFR 98.233(c). We are making a number of other revisions and clarifications to specific proposed requirements for natural gas pneumatic device venting and natural gas pneumatic pump venting and these are described in the applicable subsections of this section.

1. Direct Measurement Methods for Natural Gas Pneumatic Devices and Natural Gas Pneumatic Pumps

a. Summary of Final Amendments

Consistent with section II.B. of this preamble, we are finalizing Calculation Method 1 based on direct measurement of natural gas supplied to pneumatic devices in 40 CFR 98.233(a)(1) and supplied to pneumatic pumps in 40 CFR 98.233(c)(1), as proposed, with minor clarifications. If a continuous flow monitoring device is installed on the natural gas supply line dedicated to one or a combination of pneumatic devices, or the natural gas supply line dedicated to one or more pneumatic pumps, that are vented directly to the atmosphere, then the measured flow must be used to calculate the emissions from the pneumatic devices or pneumatic pumps, as applicable, downstream of that flow monitor. We are adding the word ''continuous'' to indicate that the flow meter is to be used on an ongoing basis, not temporarily. Temporary flow measurements are included under the provisions for Calculation Method 2. We are also finalizing that this calculation method is required when the flow is continuously measured in a supply line that serves both pneumatic devices and natural gas driven pneumatic pumps that are all vented directly to the atmosphere. We are clarifying in the final rule for both pneumatic devices and pneumatic pumps that this requirement applies if the flow monitor is capable of meeting the requirements of existing 98.234(b). In other words, if the flow is continuously measured but the meter is not capable of meeting these requirements, Calculation Method 1 is not required. When using Calculation Method 1, the flow monitor must meet the requirements specified in existing 40 CFR 98.234(b). We are also finalizing as proposed reporting requirements for each measurement location to report the type of flow monitor, the number of each type of pneumatic device being monitored at that location, and an indication of whether any natural gas driven pneumatic pumps are also monitored at that location, and the CH_4 and CO_2 emissions calculated for that monitoring location in 40 CFR 98.236(b)(3). We are also finalizing comparable reporting requirements for natural gas driven pneumatic pumps in 40 CFR 98.236(c)(3), as proposed.

For natural gas pneumatic devices that install a flow meter dedicated to measuring the flow of natural gas supplied to one or a combination of pneumatic devices that are vented directly to the atmosphere for only a portion of the year, in the final provision we are updating to clarify the proposed requirement to ''escalate'' the measured flow based on time in service by rephrasing this requirement, consistent with our intent. In the final rule, reporters using continuous flow meters for a portion of the year must calculate the total volumetric (or mass) flow for the year based on the measured volumetric flow times the total hours in the calendar year the devices were in service (*i.e.,* supplied with natural gas) divided by the number of hours the devices were in service (*i.e.,* supplied with natural gas) and the volumetric (or mass) flow was being measured. For natural gas pneumatic pumps, we are updating proposed 40 CFR 98.233(c)(1)(i)(A) to use language in the final rule that is consistent with the updates discussed above for ''escalating'' measured flow for pneumatic devices. As a result, we are also removing proposed equation W–2A from 40 CFR 98.233(c)(1)(i)(A), which is no longer necessary for pneumatic pumps, and renumbering equation W–2B to W–2A and equation W–2C to W–2B.

For natural gas pneumatic devices that do not have or do not elect to install a flow meter dedicated to measuring the flow of natural gas supplied to one or a combination of pneumatic devices that are vented directly to the atmosphere, we are finalizing requirements for Calculation Method 2 in 40 CFR 98.233(a)(2) to allow reporters to measure the natural gas emissions from each pneumatic device vented directly to the atmosphere at the well-pad site, gathering and boosting site, or facility, as applicable, using one of the measurement methods in existing 40 CFR 98.234(b) through (d). For natural gas driven pneumatic pumps that do not have or do not elect to install a flow meter dedicated to measuring the flow of natural gas supplied to one or a combination of pneumatic pumps vented directly to the atmosphere, we are finalizing requirements that the reporter either measure the natural gas emissions from each such pneumatic pump at the facility as specified in 40 CFR 98.233(c)(2) or calculate emissions from each such pneumatic pump at the facility using the default emission factor as specified in 40 CFR 98.233(c)(3). The measurement method is referred to as Calculation Method 2 for pumps and is similar to Calculation Method 2 for pneumatic devices.

For reasons discussed in section III.E.3. of this preamble, we are including a fourth calculation method for pneumatic devices allowing the use of default population emission factors and this revision led to us further assessing and updating from proposal Calculation Method 2 in the final rule. We determined that facilities with pneumatic device measurement data for some but not all sites, particularly in industry segments subject to the WEC in section 136(c) through (h) of the CAA, should be able to use those measurements for their subpart W reports. Therefore, in the final rule we are modifying Calculation Method 2 to allow facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to elect to use Calculation Method 2 for pneumatic devices for some well-pad sites or gathering and boosting sites and to elect to use other methods for other sites. However, we are specifying that, with the exception of emissions from devices for which natural gas supply is measured according to Calculation Method 1, emissions from all devices within an individual well-pad site or gathering and boosting site must be calculated using the same method (*i.e.,* Calculation Method 2 or Calculation Method 3 or Calculation Method 4, if applicable) for a given calendar year in order to prevent selective measurements of certain devices within a site that are expected to have lower emissions. This approach is consistent with our approach for equipment leaks where we have allowed and continue to allow site-by-site equipment leak surveys to constitute a complete leak detection survey for facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. This approach also encourages the use of Calculation Method 2 for selected well-pads and gathering and boosting sites at facilities that may have otherwise opted to use Calculation Method 4 rather than having to commit to measuring all devices across the large, basin-wide facilities within these industry segments. While we generally use the phrase ''well-pads'' to refer to sites in the Onshore Petroleum and Natural Gas Production industry segment that would be considered a complete survey, we know there are cases when some pneumatic devices might not be on a well-pad but are still ''associated with a single well-pad'' (as defined in 40 CFR 98.238). To ensure that the requirements to measure or monitor all pneumatic devices (or equipment leaks) at the site-level for facilities in the Onshore Petroleum and Natural Gas Production industry segment include such devices, we are finalizing the term ''well-pad site'' in 40 CFR 98.238 and defining the well-pad site to mean all equipment on or associated with a single well-pad, as discussed in section III.D. of this preamble. Thus, the site-level pneumatic device provisions for the Onshore Petroleum and Natural Gas Production industry segment include natural gas pneumatic devices present on a single well-pad and natural gas pneumatic devices that are not on that single well-pad but that are associated with that single well-pad. We are also clarifying that the reporting requirements for sources that are not reported at the equipment level must be reported at the well-pad site level.

For facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments, the election to use Calculation Method 2 is made at the facility level. In other words, if Calculation Method 2 is elected, all pneumatic devices at the facility (except those for which natural gas supply is measured according to Calculation Method 1) must be measured annually or over a multi-year cycle. We elected to retain this facility-level requirement because facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage industry segments are much smaller and less dispersed than the basin-wide facility definitions in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, and because these facilities are generally expected to have a lower number of natural gas pneumatic devices where facility-wide monitoring of devices can be accomplished within a day or two. We recognize that facilities in the Natural Gas Distribution industry segment can be very large and may have a significant number of natural gas pneumatic devices, and we recognize that this approach could encourage the use of default population emission factors. However, we have not currently defined nor proposed to define ''distribution sites'' that account for all site types within this industry segment. Furthermore, facilities in the Natural Gas Distribution industry segment are not subject to the WEC. Based on these considerations, we determined it was appropriate to retain facility-level requirements for the Natural Gas Distribution industry segment.

We are finalizing as proposed that the measurement interval for facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments be dependent on the number of devices at the facility. For facilities with 25 or fewer natural gas pneumatic devices, we are requiring measurement of all devices annually. For facilities with 26 to 50 devices, we are requiring measurement of all devices in a two-year period. The required interval period increases with every 25 devices, until reaching a maximum cycle time of 5 years for facilities with 101 or more natural gas pneumatic devices that are vented directly to the atmosphere.

Under Calculation Method 2, we are finalizing measurement requirements as proposed that each pneumatic device vent measurement, except for isolation valve actuators, must be conducted for a minimum of 15 minutes; measurements for pneumatic isolation valve actuators must be conducted for a minimum of 5 minutes. The reduced monitoring duration for isolation valve actuators is provided because these devices actuate very infrequently, and the monitoring is targeted to confirm the valve actuators are not malfunctioning (*i.e.,* emitting when not actuating) rather than to develop an average emission rate considering some limited number of actuations. If there is a measurable flow during the measurement period, the average flow rate measured during the measurement period must be used as the average flow rate for that device and multiplied by the total hours the device is in service (*i.e.,* supplied with natural gas) to calculate annual emissions (by pneumatic device type). For continuous bleed devices, if there is no measurable flow rate (*i.e.,* flow rate is below the method detection limit), we are requiring reporters to confirm the device is in service when measured and that the device type is correctly characterized. If the device was not in service, the device must be retested at a time when it is in service. If a continuous high bleed device was correctly characterized and confirmed to be in service, the device must be retested using a different measurement method and/or a longer duration until a measurable flow is detected. When these remeasurements are made, we are adding language to clarify that natural gas emissions from the device must be calculated according to 40 CFR 98.233(a)(2)(iv). For continuous low bleed devices, if there is no measurable flow rate during testing, the manufacturer's steady state bleed rate must be used to estimate the device's emissions. For cases where the manufacturer's steady state bleed rate is not available, but the device is confirmed to be a continuous low bleed pneumatic device, we are adding clarifying language that remeasurement of the device is required. For intermittent bleed devices, if there is no measurable flow rate and the device is determined not to be in service, the device must be retested at a time when it is in service. The lack of any emissions during a 5-minute or 15-minute period, as applicable, when the device is in service would indicate that the device did not actuate and that the device is seating correctly when not actuating. In cases where testing of in-service intermittent bleed devices does not detect measurable flow, we are finalizing as proposed that engineering calculations must be made to estimate emissions per activation and that company records or engineering estimates must be used to assess the number of actuations per year to calculate the emissions from that device for the reporting year. In response to concerns raised by commenters, we are clarifying in the final provisions for Calculation Method 2, consistent with our intent at proposal, that the measurements required under these methods must be made under representative conditions and not immediately after conducting maintenance on the device or after manually actuating the device. These clarifying changes are also being made for Calculation Method 2 for pneumatic pumps.

Under Calculation Method 2, if pneumatic device vent measurements are made over several years (as allowed for facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments), we are requiring as proposed that all measurements made within a multi-year measurement cycle must be used to calculate a facility-specific emission factor by device type (continuous high bleed, continuous low bleed, and intermittent bleed). The emissions measurements for the pneumatic device vents measured during the reporting year must be used directly for those devices and reporters must use the facility-specific emission factor (by device type) to calculate the emissions from the pneumatic devices that were not measured during the reporting year.

In the final rule, we are not finalizing the proposed Calculation Method 2 reporting requirements for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Boosting and Gathering industry segments pertaining to multi-year measurement cycles as this is no longer an option for facilities in these industry segments in the final rule. Reporters in these industry segments must still report other Calculation Method 2 data elements for each well-pad site or gathering and boosting site, as applicable, consisting of the total number of natural gas pneumatic devices by type measured in the reporting year, the primary measurement method, the average time the devices were in service (*i.e.,* supplied with natural gas) during the calendar year, and the GHG emissions for each type of natural gas pneumatic device.

As proposed, reporters in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments using Calculation Method 2 would report for each facility, the total number of natural gas pneumatic devices by type, the number of years in the measurement cycle, the number of devices measured in the reporting year, the primary measurement method (when emissions were measured), the value of the emission factor for the reporting year as calculated using equation W–1A and the devices upon which the emission factor is based, the average time the devices were in service (*i.e.,* supplied with natural gas) during the calendar year, and the GHG emissions for each type of natural gas pneumatic device.

We are finalizing calculation and reporting requirements as proposed for Calculation Method 2 for pneumatic pumps in 40 CFR 98.233(c)(2) and 40 CFR 98.236(c)(4), respectively. Only facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are currently required to report emissions from pneumatic pumps and based on the analysis performed as described in section III.C.1. of this preamble and documented in the subpart W TSD, we are not adding this source type for any other industry segment. As proposed, under the final rule Calculation Method 2 for pneumatic pumps allows measurements to be conducted over multiple years not to exceed 5 years for all pumps at a facility in the Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. For pneumatic pumps, we are finalizing as proposed that reporters must measure for a minimum of 5 minutes while liquid is continuously being pumped. We are also finalizing requirements, as proposed, that the emissions must be calculated as the product of the measured natural gas flow rate and the number of hours the pneumatic pump was pumping. Under Calculation Method 2 for pneumatic pumps, we are finalizing reporting data elements in 40 CFR 98.236(c)(4) per well-pad site or gathering and boosting site to include the number of years in the measurement cycle; an indication of whether emissions were measured or calculated; the primary measurement method (when emissions were measured); the value of the calculated emission factor, the total number of pumps measured and used in calculating the emission factor, the number of pumps that vented to atmosphere, and the estimated average number of hours per year that the vented pumps were pumping liquid (when the emissions were calculated); the total measured CO_2 and CH_4 emissions; and the total calculated CO_2 and CH_4 emissions.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add direct measurement methods for natural gas pneumatic devices and natural gas pneumatic pumps.

Comment: Numerous commenters opposed the requirement to measure all devices at the facility using Calculation

Method 2 within a 5-year period, indicating that this requirement would be overly burdensome. Some commenters suggested allowing facilities to develop a facility-specific emission factor based on a representative sampling of, for example, 20 percent of their pneumatic devices as an alternative to measuring all pneumatic devices. Several commenters suggested allowing the use of population factors to eliminate the burden of the measurement/monitoring requirements proposed, particularly since natural gas pneumatic devices will be phased out as a result of NSPS OOOOb and EG OOOOc regulations.

Response: We recognize that some oil and gas facilities may be geographically dispersed and may contain large numbers of pneumatic devices, so measuring all devices may require significant effort. After considering these comments, for the reasons discussed in section III.E.3. of this preamble, the EPA has decided to provide a fourth calculation method that provides a default population emission factor for all devices. This also led to us further assessing and updating from proposal Calculation Method 2 in the final rule, as explained above, to allow facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments (those segments we assessed had facilities that were geographically dispersed and contained large numbers of pneumatic devices) to elect to use Calculation Method 2 for pneumatic devices for some well-pad sites or gathering and boosting sites and to elect to use other methods for other sites, subject to certain requirements. Regarding the suggestion to allow one-time measurements on a subset of devices to create site-specific emission factors, we find the proposed requirement to instead measure all devices (over a period of up to 5 years) provides the best approach for developing a representative emission factor. This approach ensures that measurements from all pneumatic devices will ultimately be used in the development of the facility's emission factors rather than allowing measurements of only a subset of pneumatic devices to be used, which could be selected to bias the resulting emission factors low. Also, since the NSPS requirements are expected to phase out these devices across many industry segments, it is unclear how representative the measurements made over the next few years will be for devices that may remain in operation 5 years from now. As such, we did not revise the requirements to allow the development and use of a site-specific emission factor for natural gas pneumatic devices based on a one-time measurement of a subset of devices. However, our final Calculation Method 2 requirements we noted in this response (which allow measurements of natural gas pneumatic devices at some well-pads or gathering and boosting sites using Calculation Method 2 and allow the use of default population emission factors for other sites within that facility) should appropriately address commenters concerns, and should promote the use of measurement data for facilities in the Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. As we noted, this approach is consistent with our approach for equipment leaks where we have allowed and continue to allow site-by-site equipment leak surveys to constitute a complete leak detection survey for facilities in the Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting industry segments.

Comment: One commenter suggested that Calculation Method 1 be used on representative number of devices to ensure that measurements or monitoring conducted under Calculation Methods 2 or 3 are accurate and representative. The commenter also recommended that the EPA directly address the issue of timing pre-inspections and repairs before formal measurement and monitoring efforts to comply with GHGRP are carried out to ensure measurements are done randomly with respect to repairs and that the EPA require operators to report the date of measurements and inspections performed for Calculation Method 2 or 3, and the date(s) of any repairs performed on pneumatic controllers, including ''resetting'' controllers by manually actuating them. According to the commenter, it would be essential to ensure that operators are not manipulating results of Calculation Method 2 or 3 by repairing malfunctioning controllers shortly before inspecting them or measuring their emissions.

Response: We believe it would be difficult to ensure that a subset of devices measured using continuous flow meters (Calculation Method 1) would be representative of the pneumatic devices for which Calculation Method 2 or 3 would be used. We agree that any measurements or monitoring conducted according to Calculation Method 2 or 3 should be done during representative periods, which would preclude monitoring immediately after device repairs or manual actuations to reset the device. Monitoring immediately after repairs or manual actuations of devices that are stuck open would result in underestimating emissions by not capturing the emissions associated with malfunctioning devices and devices stuck open that occurred prior to the repair or manual actuation, and that are likely to reoccur after the repair or manual actuation. Therefore, in the final provisions we have added language in both Calculation Methods 2 and 3 that measurements or monitoring must be conducted during representative conditions and must not be conducted immediately after device repair or manual actuation. With these changes, we expect both Calculation Method 2 and 3 to provide accurate estimates of emissions from pneumatic devices as they are based on direct measurement of emissions, monitoring to identify periods of malfunction, and emission factors representative of average emissions and inclusive of malfunction emissions. Finally, we note that under the final rule, we will still be able use the data obtained when Calculation Method 1 is employed as a way to assess the data collected via Calculation Method 2 or 3. For the reasons stated above, we determined that it is not necessary or appropriate at this time to require that a representative number of devices be measured using continuous flow meters.

2. Intermittent Bleed Pneumatic Device Surveys

a. Summary of Final Amendments

The EPA is finalizing 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.B. of this preamble. Specifically, we are finalizing provisions in 40 CFR 98.233(a)(3) providing an alternative calculation methodology for facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments that monitor for malfunctioning intermittent bleed pneumatic devices analogous to a ''leaker factor'' approach used for equipment leaks. In this final rule, after consideration of concerns raised by commenters regarding the applicability of emission factors developed based on data from Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to other segments of the industry, we are limiting this method to Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments because our assessment is that those are the only segments for which we have the appropriate data needed to develop the emission factors for this approach at this time. We included this ''leaker factor'' approach in the 2022 Proposed Rule using data from an API study as presented by Tupper (2019),[40] and we included this ''leaker factor'' approach in the 2023 Subpart W Proposed Rule using peer reviewed study data from Luck et al. (2019).[41] The study presented by Tupper included pneumatic devices predominately at oil and gas production sites; the Luck et al. (2019) study evaluated pneumatic devices exclusively and gathering and boosting compressor stations. We decided to use the Luck *et al.* (2019) data in the 2023 Subpart W Proposed Rule because it was peer reviewed and because we did not have raw data from the API study to verify the summary data presented by Tupper. These raw data were ultimately provided by API as part of their comments on the 2023 Subpart W Proposal.

Because of the differences in the scope of these studies, as discussed in further detail in section III.E.2.b. of this preamble, we are finalizing this ''leaker factor'' approach using the Tupper (2019) equation parameters for well-pad sites and using the Luck et al. (2019) equation parameters for gathering and boosting sites. We refer to this monitoring/leaker factor approach as Calculation Method 3 for pneumatic devices. As noted in the GRI/EPA (1996) study, natural gas intermittent bleed pneumatic devices in the natural gas processing, transmission, and storage segments are used only for isolation valve actuators.[42] These isolation valve actuators operate infrequently and have different designs than the pneumatic device controllers used in the production and gathering and boosting industry segments. Therefore, we determined it was inappropriate to use either of these equation factors for the other natural gas industry segments.

As proposed, if Calculation Method 3 is elected, all intermittent bleed pneumatic devices that vent to the atmosphere at the well-pad or gathering and boosting site (except those for which natural gas supply is measured according to Calculation Method 1) must be monitored at least once in the calendar year according to the leak detection methods in 40 CFR 98.234(a)(1) through (3), but with a monitoring duration of at least 2 minutes or until a malfunction is identified. As discussed in section III.E.1.b. of this preamble, after consideration of comment, we are clarifying in the final provisions for Calculation Method 3, consistent with our intent at proposal, that monitoring conducted for Calculation Method 3 must be performed under representative conditions and not immediately after conducting maintenance on the device or after manually actuating the device.

Because under the final provisions we are allowing different well-pads or gathering and boosting sites at the same facility in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to elect to use different calculation methods (and thus are no longer including in the final provisions the proposed requirement to measure or monitor all devices at a facility within a 5-year period), we are specifying that, with the exception of emissions from devices for which natural gas supply is measured according to Calculation Method 1, emissions from all devices within an individual well-pad or gathering and boosting site must be calculated using the same method (*i.e.,* Calculation Method 2 or Calculation Method 3 or Calculation Method 4, if applicable) for a given calendar year.

Under Calculation Method 3, all intermittent bleed pneumatic devices that are vented directly to the atmosphere present at the well-pad or gathering and boosting site (except those for which natural gas supply is measured according to Calculation Method 1) must be monitored to identify malfunctioning devices at least once in the calendar year.

As proposed, under the final provisions, if a ''leak'' is observed from the intermittent bleed pneumatic device for more than 5 seconds during a device actuation, then the device is considered to be ''malfunctioning'' and the malfunctioning device emission factor (similar to a leaker emission factor) would be applied to that device. However, as discussed in section III.E.2.b. of this preamble, we are including special provisions for devices that actuate for more than 5 seconds during normal operations, such as isolation valves on large diameter pipes, to allow reporters to clearly identify these devices using a permanent tag that includes the allowable actuation time for the device under normal operating conditions. Emissions from intermittent bleed pneumatic devices that were not observed to be malfunctioning must be calculated based on the default emission factor for ''properly functioning'' intermittent bleed pneumatic devices. We are finalizing as proposed in the definition of the variable ''T_z'' in equation W–1C that the time that a device is assumed to be malfunctioning must be determined following the same procedures as the determination of the duration of equipment leaks identified during a leak survey conducted under 40 CFR 98.233(q) (see the variable ''$T_{p,z}$'' in equation W–30 for equipment leaks). For example, if only one survey of intermittent bleed natural gas pneumatic devices is conducted during the reporting year, then any device found to be malfunctioning during the survey would be required to be assumed to be malfunctioning for the entire year. This approach effectively assumes that the emissions identified during the monitoring survey are representative of the emissions that occur throughout the year. We recognize that some malfunctioning devices may be repaired, but other devices may also begin to malfunction. Based on our analysis of equipment leak durations as conducted to support leaker factor revisions to subpart W finalized in 2016, we maintain that this is the most representative and accurate assumption when determining emission from leaks during annual or periodic surveys.[43]

Under Calculation Method 3, we are also finalizing as proposed requirements that emissions from continuous bleed pneumatic controllers (other than those for which the natural gas supply flow is measured as specified in Calculation Method 1) would be determined either by annually measuring the emissions from the pneumatic device vent

[40] Tupper, P. 2019. ''API Field Measurement Study: Pneumatic Controllers'' presented at the EPA Stakeholder Workshop on Oil and Gas in Pittsburgh, Pennsylvania, on November 7, 2019. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[41] Luck, B., *et al.,* 2019. ''Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations.'' *Environmental Science & Technology Letters* 6 (6), 348–352. DOI: 10.1021/acs.estlett.9b00158. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[42] GRI/EPA, 1996. Methane Emissions from the Natural Gas Industry. Volume 12 Pneumatic Devices. GRI–94/0257.29; EPA–600/R–96–080I. June. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[43] De Figueiredo, M., 2016. Memorandum to Docket ID No. EPA–HQ–OAR–2015–0764 regarding ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule.'' November 1. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

following the methods provided in Calculation Method 2 or by using applicable default population emission factors for continuous high bleed and continuous low bleed pneumatic devices.

We are finalizing as proposed reporting requirements for intermittent bleed pneumatic devices for which emissions are calculated using Calculation Method 3 under 40 CFR 98.236(b)(5), except (1) those proposed reporting requirements pertaining to multi-year measurement cycles as this is no longer an option under the final provisions, and (2) those proposed reporting requirements applicable to segments other than Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, which are not permitted the option to use this methodology under the final provisions. Therefore, reporters using proposed Calculation Method 3 must report for each well-pad or gathering and boosting site, as applicable, the total number of natural gas pneumatic devices by type, the method used to estimate emissions from continuous bleed natural gas pneumatic devices, the frequency of monitoring for intermittent devices, the number of devices at the facility monitored in the reporting year, the number found to be malfunctioning, the average time the malfunctioning devices were assumed to be malfunctioning under 40 CFR 98.236(b)(5), the average time that devices that were monitored but were not detected as malfunctioning year were in service (*i.e.,* supplied with natural gas) during the calendar year, and the GHG emissions for each type of natural gas pneumatic device. For more information regarding Calculation Method 3 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–2023–0234.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to survey intermittent bleed natural gas pneumatic devices.

Comment: Similar to the comments received regarding Calculation Method 2, numerous commenters opposed the requirement to monitor all devices at the facility within a 5-year period, indicating that this requirement would be overly burdensome. Some commenters suggested allowing facilities to develop a facility-specific emission factor or fraction of malfunctioning devices based on a representative monitoring of, for example, 20 percent of their intermittent bleed pneumatic devices. Several commenters suggested allowing the use of population factors for intermittent bleed devices to eliminate the burden of the monitoring requirements proposed.

Response: As explained previously, in the final rule the EPA is adding a fourth calculation method that provides a default population emission factor for all devices. This option, combined with the update from proposal in the final provisions allowing different well-pad or gathering and boosting sites at the same facility in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to elect to use different calculation methods, appropriately addresses commenters' concerns regarding the requirement to measure or monitor all natural gas pneumatic devices in such facilities that we agreed could be geographically dispersed and contain a large number of pneumatic devices. Under the final provisions for these industry segments that may use Calculation Method 3, the proposed requirement to measure and monitor all devices at a facility over a period of up to 5 years is not included and instead was updated to a requirement to calculate emissions from all devices within an individual well-pad or gathering and boosting site using the same method (*i.e.,* Calculation Method 2 or Calculation Method 3 or Calculation Method 4, if applicable) for a given calendar year. Regarding the suggestion to allow monitoring on a subset of devices to create site-specific fraction of malfunctioning devices as opposed to all devices within an individual well-pad or gathering and boosting site, we expect that the fraction of malfunctioning devices will be a function of the age of the device, make and model number of the device, and the number of actuations per year of the device. We also expect that the number of devices found malfunctioning would change based on the implementation of a monitoring survey (assuming some or all of the malfunctioning devices are repaired). Requiring only a subset of devices to be monitored would allow facilities to monitor devices expected to emit at lower rates and bias the resulting emission factor low. Therefore, we find the final requirement to monitor all devices at a site provides the best approach for developing a representative fraction of malfunctioning devices for that year for that site. Also, since the NSPS requirements are expected to phase out these devices across many industry segments, it is unclear how representative the fraction of malfunctioning devices as determined over the next few years will be for devices that may remain in operation 5 years from now. As such, we did not revise the requirements to allow the development and use of a site-specific fraction of malfunctioning intermittent bleed natural gas pneumatic devices. However, we expect that the updates in the final provisions that we discussed earlier in this response to promote the use of monitoring data for facilities in the Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting segments, given that they allow monitoring of intermittent bleed natural gas pneumatic devices at some well-pads or gathering and boosting sites using Calculation Method 3 and allow the use of default emission factors for other sites within that facility. This approach is consistent with our approach for equipment leaks where we have allowed and continue to allow site-by-site equipment leak surveys to constitute a complete leak detection survey for facilities in the Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting industry segments.

Comment: We received numerous comments regarding the proposed emission factors for properly functioning and malfunctioning intermittent bleed pneumatic devices within the equation for Calculation Method 3. Several commenters suggested that the properly operating device emission factor from Tupper as included in the 2022 Proposed Rule should be used over the factor from Luck et al. (2019) as included in the 2023 Subpart W Proposal. According to these commenters, the Tupper study is more representative because it measured a larger number of devices predominately at production sites whereas Luck study included only gathering and boosting sites and measured emissions from much fewer devices. A couple of commenters suggested developing an aggregated emission factor considering the data from both of these studies and one commenter suggested that the EPA also assess data from Footer *et al.* (2023) in developing aggregated emission factors for use with Calculation Method 3. According to one commenter, Allen *et al.* (2015) reported a national average of 14.0 scf/hr for controllers (both properly functioning and not properly functioning) associated with compressors, which is approximately three times the average emission rate for controllers in service of other equipment (5.0 scf/hr for both properly functioning and not functioning properly). Some commenters suggested that the EPA allow reporters to use engineering calculations for intermittent bleed devices determined to be properly functioning in place of or as an alternative to the default emission factor for properly functioning intermittent bleed pneumatic devices.

Response: We agree with commenters that the API/Tupper study was primarily focused on production sites while the Luck study was focused on gathering and boosting sites. After considering these comments, we determined it was appropriate to base the final emission factors on the API/Tupper study for well-pad sites at an Onshore Petroleum and Natural Gas Production or Onshore Petroleum facility because the API/Tupper study was focused on production sites. We also determined it was appropriate to base the final emission factors on Luck et al. (2019) for gathering and boosting sites at an Onshore Petroleum and Natural Gas Gathering and Boosting facility because the Luck study was focused on gathering and boosting sites. We also determined it was appropriate to base the final emission factors on these respective studies because, based on the comparison of pneumatic device emission factors between devices associated with compressors and devices associated with other equipment as presented in Allen et al. (2015),[44] it is logical to conclude that properly operating intermittent bleed devices at gathering and boosting facilities, which often have more compressors, would have higher emissions per device than devices at onshore production facilities, which have fewer compressors.

For other industry segments, we initially expected that the pneumatic devices used at the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment with its compressor stations would be more analogous to the other mid and downstream industry segments. This is evidenced by the fact that the correctly functioning intermittent bleed device emission factor of 2.8 scf/hr from Luck *et al.* (2019) which is based on measurements at gathering and boosting sites, is very similar to the historic population emission factor used in subpart W for the Onshore Natural Gas Transmission Compression industry segment of 2.35 scf/hr, which was based on engineering calculations that assume the device is properly functioning. However, after reviewing available data, we determined that we did not have sufficient data to provide separate malfunctioning and non-malfunctioning emission factors for Calculation Method 3 for Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution facilities, and are not allowing Calculation Method 3 as an option for these industry segments at this time. As noted in the GRI/EPA 1996 study, natural gas intermittent bleed pneumatic devices used in the natural gas processing, transmission, and storage industry segments are isolation valve actuators. These isolation valve actuators actuate seldomly and have different designs and functions from the natural gas intermittent bleed pneumatic controllers measured in the API/Tupper study or the Luck *et al.* (2019) study. We found no study data available focused on isolation valve actuators at these ‘‘downstream’’ industry segments by which to characterize emissions from malfunctioning devices. For more information on our review of available data on pneumatic devices by industry segment, see the subpart W TSD, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

We also considered whether the correctly functioning emission factor should be based on engineering calculations or other measurement data. While we agree that engineering calculations can be accurate, this is the case only when accurate estimates of the actuation frequency can be made, which will not necessarily be the case for all intermittent devices. We also considered that, if reporters could elect to use the default factor for some intermittent bleed devices and use engineering calculations for other devices, facilities would likely use engineering calculations only for those devices that have emissions less than the default and use the default for all other devices, thereby biasing the emissions low and not resulting in accurate total emissions reported. We also note that the use of engineering calculations is allowed under Calculation Method 2 for devices that do not have measurable emissions during the measurement period. Reporters preferring to use device-specific engineering calculations for properly functioning intermittent bleed pneumatic devices are encouraged to use Calculation Method 2. Therefore, we are not providing or allowing facilities to estimate device-specific emissions based on engineering calculations when using Calculation Method 3.

Comment: A few commenters noted that some intermittent bleed devices actuate longer the 5 seconds during normal actuations such that assigning these devices as malfunctioning would overstate their emissions when applying Calculation Method 3. One commenter noted that, as an industry rule of thumb, the actuation time for a valve opening and closing is one to two seconds per inch of pipe diameter. According to the commenter, the proposed monitoring methodology would mistakenly designate devices on pipes six inches or greater in diameter as ‘‘malfunctioning.’’ Another commenter noted that throttling intermittent bleed pneumatic devices should not be assumed to be malfunctioning or leaking merely because it actuates for longer than 5 seconds. This commenter recommended that the final rule should provide that an operator must make an engineering determination confirmed by field inspections that a throttling pneumatic device is actually malfunctioning before using the malfunctioning device emission factor.

Response: While we maintain that the 5-second duration of emissions is reasonable for the vast majority of pneumatic devices, we acknowledge that some larger devices may have actuation times exceeding 5 seconds. Therefore, we are including provisions in the final rule for facilities to *a priori* identify those select devices that are expected to have actuation emissions lasting longer than 5 seconds (like an isolation valve on a 12-inch pipe) and the actuation times expected for each of those devices. In the final rule, we are requiring reporters that use Calculation Method 3 to specifically identify those intermittent bleed devices with actuation times longer than 5 seconds using a tagging system or similar method that indicates the expected actuation time for the device. Facilities will also be required to report the number of devices for which they are using extended emission duration provisions. With these and corresponding provisions for devices with longer actuation times, we maintain that the final rule provides adequate provisions to accurately assess whether an intermittent bleed device is properly functioning during a monitoring survey.

[44] Allen, D.T., *et al.,* 2015. ‘‘Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers.’’ *Environ. Sci. Technol.* 49, 633–640. dx.doi.org/10.1021/es5040156. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

3. Revisions to Emission Factors

a. Summary of Final Amendments

Regarding pneumatic devices, in our 2022 Proposed Rule, we proposed to update the default population emission factors for all device types based on recent study data. In the 2023 Subpart W Proposal, for intermittent bleed devices, we proposed to remove default population emission factors altogether and require measurement or monitoring of these devices. In the proposal, we requested comment on this approach and also requested comment on default population emission factors for intermittent bleed devices in the event that this option was retained in the final rule. In this final rule, under Calculation Method 4, we are allowing the option to continue to use default population emission factors to estimate emissions from both intermittent bleed devices and continuous bleed devices at the well-pad site, gathering and boosting site, or facility level, as applicable. Consistent with the overall intent of this final rulemaking for reporting to be based on empirical data, consistent with section II.B. of this preamble, if measurement or survey data are available, we are requiring that emissions be calculated based on those data when available. Therefore, in the final rule, reporters cannot use Calculation Method 4 for devices for which natural gas supply is measured according to Calculation Method 1 or for devices at sites for which measurements or monitoring were conducted in accordance with Calculation Method 2 or 3. For all other devices, Calculation Method 4 is allowed. Regarding pneumatic pumps, the final method based on a default emission factor is the same as the methodology in 40 CFR 98.233(c) of the existing rule and is referred to as Calculation Method 3 for pneumatic pumps in the final rule. As proposed, for pneumatic pumps we are maintaining the existing default population emission factor.

Under Calculation Method 4 for pneumatic devices, we are finalizing that the default population emission factor for continuous low bleed pneumatic devices is 6.8 standard cubic feet per hour per device (scf/hr/device) for all applicable industry segments, based on recent study data and consistent with the 2023 Subpart W Proposal. For continuous high bleed pneumatic devices under Calculation Method 4, consistent with the 2023 Subpart W Proposal, based on recent study data we are finalizing a default population emission factor of 21 scf/hr/device for devices in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments and a default population emission factor of 30 scf/hr/device for continuous high bleed devices in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments.

For facilities in the Onshore Petroleum and Natural Gas Production and in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, we are finalizing an intermittent bleed pneumatic device default population emission factor of 8.8 scf/hr/device and for facilities in the Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments, we are finalizing an intermittent bleed pneumatic device default population emission factor of 2.3 scf/hr/device, based on recent study data and consistent with those population emission factors that we included in the 2022 Proposed Rule and that we discussed in the preamble to the 2023 Subpart W Proposal and for which we requested comment in the event the final rule included such a method for intermittent bleed devices.

For more information regarding this review and development of the emission factors, see the subpart W TSD, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

Finally, we note that for pneumatic pumps, we are maintaining the existing default population emission factor, as proposed. Reporters that do not have or do not elect to install a flow meter on the natural gas supply line dedicated to any one or more natural gas driven pneumatic pumps and that do not elect to measure the volumetric flow rate of emissions from all the natural gas driven pneumatic pumps vented directly to the atmosphere at a well-pad or gathering and boosting site are required to continue using the current default population emission factor for pneumatic pumps vented directly to the atmosphere under Calculation Method 3 for pneumatic pumps.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments and requests for comments on population emission factors for natural gas pneumatic devices and natural gas pneumatic pumps.

Comment: Numerous commenters recommended that the EPA provide a default emission factor for intermittent bleed devices. Many commenters supported the EPA's suggested intermittent bleed pneumatic device emission factor of 8.8 scf/hr; a few commenters suggested this default emission factor should be lower. Commenters suggesting a lower emission factor indicated that if the EPA used a device-weighted average, rather than considering averages by study, and had included data from the additional studies review, a lower emission factor would be calculated. Several commenters opposed the proposed default emission factor for continuous low bleed devices of 6.8 scf/hr arguing that it is incongruous for a low bleed device, which is defined as a device with continuous bleed rates less than 6 scf/hr, to have an emission factor greater than 6 scf/hr.

Response: After considering these and other comments, the EPA is adding a fourth calculation method that provides a default population emission factor for all devices. In the final rule, we are including a default population emission factor of 8.8 scf/hr for intermittent bleed pneumatic devices in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. For Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, and Natural Gas Distribution industry segments, we are finalizing an intermittent bleed default population emission factor of 2.3 scf/hr. We determined that these are the most appropriate values after considering all available data. Regarding commenters suggesting that we develop the emission factor weighted by the number of device measurements, we decided that may not be representative. First, the Prasino Group, which had high number of device measurements, selected device model numbers to test and tested 30 of each model number. The equal number of measurements by model number is not necessarily reflective of the proportion of devices in use at U.S. production and gathering and boosting facilities. Second, Luck *et al.* (2019) measured emissions from pneumatic devices over 76 hours, which is 150 to 300 times longer than other measurement studies. As such, even though Luck et al. (2019) measured fewer devices, their measurements are expected to be much more accurate and representative of device emissions, particularly for devices that may have excess emissions sporadically over time. Based on the different study approaches and measurement methods, we determined that equally weighting each study's average emission factor was appropriate. We did not include study data from studies that relied entirely or predominately on engineering calculations because those studies would not fully characterize excess emissions from malfunctioning devices, so would likely be biased low. For more information on our development of the final population emission factors, see the subpart W TSD for the final rule, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

With respect to the proposed continuous low bleed default population emission factor of 6.8 scf/hr, we maintain that this is the appropriate default population emission factor under Calculation Method 4, as under this method the emission factor needs to account for times the continuous low bleed device may be malfunctioning. Most reporters use the manufacturer's design steady state bleed rates to determine whether a continuous bleed device is classified as low or high bleed. Therefore, they classify a continuous bleed controller as a low bleed device when the manufacturer's design steady state bleed rate is 6 scf/hr or less. However, across numerous measurement studies,[45 46 47] the study data show that ''malfunctioning'' low bleed devices can emit at higher rates than the design steady state bleed rate. That is, devices with steady state bleed rates of less than 6 scf/hr (''low bleed'' devices) could often have measured emissions higher the 6 scf/hr. We consider it essential to set the low continuous bleed emission factor at the average emission rate determined across all low bleed devices, including those devices that exhibited excess emissions associating with malfunctioning devices. As such, we maintain that the final low bleed default population emission factor is the most appropriate and accurate value for estimating average emissions from these devices under Calculation Method 4.

4. Hours of Operation of Natural Gas Pneumatic Devices

a. Summary of Final Amendments

As proposed, consistent with section II.D. of this preamble, we are finalizing revisions to the definition of variable ''T_t'' in existing equation W–1 (which is now equation W–1B) in 40 CFR 98.233 and the corresponding reporting requirements in proposed 40 CFR 98.236(b)(4)(ii)(C)(*4*), (b)(4)(iii)(C)(*4*), and (b)(5)(i)(C)(*2*) to use the term ''in service (*i.e.,* supplied with natural gas)'' rather than ''operational'' or ''operating,'' to clarify the original and current intended meaning of that variable and term. We are making two minor revisions to the proposed calculation requirements within Calculation Method 2 to clarify the requirements with respect to ''in service'' time. First, we are adding a paragraph at 40 CFR 98.233(a)(2)(iii)(E) to clarify how to use calculate the average measured emission rate using the entire time of the measurement period, not just times when the device is actively actuating, consistent with the rate needed considering ''in service'' time. Second, we are deleting proposed paragraph at 40 CFR 98.233(a)(2)(v)(C)(*6*), which specified how to calculate an annual average emission rate based on actuation volumes and number of actuation cycles and that time ''in service.'' This average emission rate is not needed under this scenario and is not needed to calculate the emissions under Calculation Method 2. Therefore, we are removing this calculation requirement in the final rule.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to clarify the time variable and meaning of ''in service'' time for use in the pneumatic device calculation methods.

Comment: Most commenters supported the clarification regarding time in service. A few commenters opposed the use of in service time because, according to these commenters, use of the in service time (default of 8,760 hours per year) assumes that intermittent bleed devices are continuously emitting when applying the population emission factor and even when applying Calculation Method 3 for properly functioning devices. Because intermittent bleed devices do not continuously emit natural gas under normal operations, the commenters suggest that reporters be allowed to use actuation times and cycle counts to determine the time parameter in the pneumatic device emission calculations. According to these commenters, this approach would allow the use of ''empirical data'' and yield more accurate emissions estimates.

Response: We strongly disagree with the commenters that actuation time rather than in-service time should be used in Calculation Method 3 or 4. The emission factor used in Calculation Method 3 for correctly operating intermittent bleed devices is not the emission rate measured only during an actuation but represents the average emission rate measured across the measurement period and includes periods when the device is actuating AND when it is not. Thus, the emission factor's denominator is the time the device is ''in service (*i.e.,* supplied with natural gas)'' and not the time the device was actuating. Therefore, we must use the same definition of time in service when applying the emission factors used in Calculation Method 3 to determine annual emissions. The exact same argument applies when using the default population emission factors in Calculation Method 4. We note that in many studies, no emissions were measured from the devices over a 15-minute period. These ''zero'' emissions were factored into the average population emission factor in these studies. Because the emission factors were developed considering cumulative emissions released divided by the cumulative time period the device was being measured (including measurement periods when there were no actuations), the only accurate definition of the time variable in the pneumatic device calculation equations is the time in service (*i.e.,* the time the device is supplied with natural gas). Use of actuation times in these equations would significantly underestimate emissions and would not result in accurate reporting of total emissions. We note that this use of consistent logic in matching between the measurement approach and the calculation approach is reflected within each calculation method. For example, when measurements are made under Calculation Method 2, we require calculation of the average emission rate over the measurement period. We are adding paragraph at 40 CFR 98.233(a)(2)(iii)(E) to clarify how this

[45] The Prasino Group (2013). ''Determining Emissions Factors for Pneumatic Devices in British Columbia—Final Field Sampling Report.'' November 15. Also, ''Final Report—For Determining Bleed Rates for Pneumatic Devices in British Columbia.'' December 18. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[46] Allen, D.T., *et al.* (2015). ''Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers.'' *Eviron. Sci. Technol.* No. 49, pp. 633–640. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[47] Luck, B., *et al.,* 2019. ''Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations.'' *Environmental Science & Technology Letters 6* (6), 348–352. DOI: 10.1021/acs.estlett.9b00158. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

calculation is made and that it includes the entire measurement period, not just times when the device is actuating. This is also consistent with how the emission factors are calculated under Calculation Methods 3 and 4 and consistent with the use of ''in service'' hours for the annual emission calculation. When there is no measurable flow from the device, actuation volumes and number of actuation cycles can be used under Calculation Method 2 to estimate annual emissions from those devices and the time ''in service'' is not needed. We proposed to require calculation of the annual average emission rate considering the number of hours the device is ''in service'' but that requirement does not impact the annual emissions rate to be reported for that device. Since the average emission rate is not used in this case, we are removing that paragraph of the calculation procedures for the average emission rate, which was proposed at 40 CFR 98.233(a)(2)(v)(C)(*6*).

5. Natural Gas Pneumatic Devices and Natural Gas Driven Pneumatic Pumps Routed to Control

We understand that emissions from some natural gas pneumatic devices and/or natural gas driven pneumatic pumps are routed to control (*i.e.,* a flare, combustion unit, or vapor recovery system). The population emission factor is based on natural gas vented directly to the atmosphere from these pneumatic devices/pumps and does not accurately reflect emissions from controlled pneumatic devices/pumps. Therefore, consistent with section II.B. of this preamble, we are finalizing as proposed revisions to 40 CFR 98.233(a) and (c) to clarify requirements for calculating emissions from natural gas pneumatic devices and natural gas driven pneumatic pumps, respectively, that are vented directly to the atmosphere versus pneumatic devices/pumps that are routed to control, consistent with the intent of this rule. The EPA received only minor comments regarding natural gas pneumatic devices and natural gas driven pneumatic pumps routed to control. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

We are finalizing revisions to 40 CFR 98.233(a) and (c) to clarify that the existing population emission factor calculation methodology is intended to apply only to pneumatic devices/pumps vented directly to the atmosphere, as proposed. The new calculation methodologies described in sections III.E.1. and 2. of this preamble also specify that they apply only to pneumatic devices/pumps vented directly to the atmosphere.

We are finalizing requirements that flared emissions from natural gas pneumatic devices or pumps are not required to be calculated and reported separately from other flared emissions, consistent with the 2023 Subpart W Proposal. Instead, emission streams from natural gas pneumatic devices or 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, as proposed, emissions from natural gas pneumatic devices or 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). We are also finalizing as proposed provisions that specify that reporters would not calculate or report emissions from natural gas pneumatic devices or pumps if the emissions are routed to vapor recovery and are not subsequently routed to a combustion device (*e.g.,* are routed back to process or sales). Finally, we are making clarifying edits to the language in 40 CFR 98.233(c)(4) for pumps that are vented to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery for another part of the year.

We are also finalizing as proposed requirements in 40 CFR 98.236(b)(2) and 98.236(c)(2) to report the total number of continuous low bleed, continuous high bleed, and intermittent bleed natural gas pneumatic devices and the total number of natural gas driven pneumatic pumps at the site (regardless of vent disposition), the number of these devices/pumps that are vented to the atmosphere for at least a portion of the year, and the number of these devices/pumps that are routed to control for at least a portion of the year (which includes natural gas pneumatic devices/pumps routed to a flare, combustion unit, or vapor recovery system). We added a sentence at 40 CFR 98.233(a)(8) and (c)(4) to further clarify these reporting requirements apply even when emissions from the pneumatic devices or pumps are required to be reported under other sources (flares or combustion) or not required to be reported.

F. Acid Gas Removal Unit Vents

1. Reporting of Methane Emissions From Acid Gas Removal Units

a. Summary of Final Amendments

Reporters currently report only CO_2 emissions from AGR vents using one of the four calculation methodologies provided in 40 CFR 98.233(d). The EPA is finalizing as proposed the amendments to 40 CFR 98.233(d) and 98.236(d) to require calculation and reporting of CH_4 from AGR vents, which will improve the coverage of total CH_4 emissions reported to subpart W, consistent with section II.A. of this preamble. As proposed, the final amendments provide three calculation methods for reporting of CH_4 from AGR vents and nitrogen removal unit vents, with modifications from proposal regarding when those methods apply. The final Calculation Method 2 requires, as proposed, that if a vent flow meter is installed, including the volumetric flow rate monitor on a continuous emissions monitoring system (CEMS) for CO_2, the reporter must use the annual volume of vent gas from the flow meter and the CH_4 composition from either a continuous gas analyzer or quarterly gas samples to calculate emissions using equation W–3 (40 CFR 98.233(d)(2)). However, based on consideration of public comments regarding safety concerns with measuring the composition of vent gas if high concentrations of H_2S are expected to be present, the EPA is finalizing a modification from proposal in Calculation Methods 2 and 4 for CH_4 and an amendment to Calculation Methods 2 and 4 for CO_2 that allows reporters to use Calculation Method 4, modeling simulation via software (40 CFR 98.233(d)(4)), for an AGR even if a vent flow meter, including the volumetric flow rate monitor on a CEMS for CO_2, is installed. Reporters who elect to use Calculation Method 4 for an AGR with a vent flow meter will be required to determine the difference between the annual volume of vent gas measured by the vent meter and the simulated annual volume of vent gas (as calculated by new equation W–4D), and report the annual volume of vent gas measured by the vent meter, the simulated annual volume of vent gas from the model, and a reason for the difference in flow rates if the difference (as calculated by new equation W–4D) is greater than 20 percent. The EPA considers the selected

20 percent interval to be low enough to ensure reasonable agreement between the flow rates obtained by the different methods but high enough to reasonably account for the expected uncertainties, as described in more detail in section III.F.1.b. of this preamble.

Under the final provisions, if neither a CEMS for CO_2 nor a vent flow meter is installed, for CH_4 reporters may use Calculation Method 3, engineering equations, with one exception (40 CFR 98.233(d)(3)) or Calculation Method 4, modeling simulation via software (40 CFR 98.233(d)(4)). For Calculation Method 3, the EPA is finalizing as proposed the revisions to the existing equations W–4A and W–4B and finalizing as proposed the new equation W–4C. With the addition of CH_4 as a component for these equations, reporters need to have information on four parameters rather than the three they currently need to know. Based on consideration of public comment, the EPA is adding a specification in the final provision that if the volumetric emissions calculated using Calculation Method 3 are less than or equal to 0 cubic feet per year, the reporter may not use this calculation method for either CH_4 or CO_2 and must instead use Calculation Method 4. As noted in section III.F.1.b. of this preamble, there could be times when the normal variability in flow rate and concentration measurements could result in concerns with the accuracy of Calculation Method 3, particularly for CH_4, and in those cases, modeling simulations can take into account more variables than the final engineering equations, which will result in more accurate emissions calculations. For Calculation Method 4, the EPA is finalizing as proposed the addition of the CH_4 content of the feed natural gas and the outlet natural gas as parameters that must be used to characterize emissions. This specification is analogous to the existing requirement to use acid gas content of the feed natural gas and the acid gas content of outlet natural gas to characterize CO_2 emissions.

The EPA is also finalizing as proposed the addition of relevant reporting elements for CH_4 from each AGR to 40 CFR 98.236(d). The additional data elements include annual CH_4 emissions vented directly to the atmosphere; annual average volumetric fraction of CH_4 in the vent gas if using Calculation Method 2; additional inputs for Calculation Method 3, depending on the equation used (*i.e.,* as applicable, the annual average volumetric fraction of CH_4 in the natural gas flowing out of the AGR, annual average volumetric fraction of CH_4 content in natural gas flowing into the AGR, annual average volumetric fraction of CO_2 in the vent gas exiting the AGR and annual average volumetric fraction of CH_4 in the vent gas exiting the AGR); and the CH_4 content of the feed natural gas and outlet natural gas if using Calculation Method 4.

Under the current provisions of subpart W, reporters with AGRs routed to flares are required to report the CO_2 emissions from the AGR that pass through the flare as AGR vent emissions, and the emissions that result from combustion of any CH_4 in the AGR vent stream are reported as flare stack emissions. The EPA proposed to revise subpart W such that AGR vents routed to a flare would follow the same calculation requirements as other emission source types and would begin reporting flared AGR emissions (CO_2, CH_4, and N_2O) separately from vented AGR emissions (CO_2 and CH_4). While the final flaring provisions differ somewhat from the proposed provisions, as explained in more detail in section III.N. of this preamble, the final amendments generally specify as proposed that vented AGR emissions include only those emissions vented directly to the atmosphere and emissions routed to a flare are considered flare stack emissions. In a similar amendment, we are finalizing as proposed the specification that for AGR vents routed to an engine, reporters will calculate CO_2, CH_4, and N_2O emissions using the provisions of 40 CFR 98.233(z) or subpart C, whichever is applicable to that industry segment. We are also finalizing as proposed the requirement that AGRs routed to an engine or flare for the entire year report the information in amended 40 CFR 98.236(d)(1) except for the calculation method and the CO_2 and CH_4 emissions from the unit, if the flare emissions are calculated using continuous monitors, as finalized in 40 CFR 98.233(n). If the AGR routed to an engine or flare only for part of the year, the other information in amended 40 CFR 98.236(d)(1) will be required to be reported for the part of the year in which emissions were vented directly to the atmosphere. Consistent with the final provisions of 40 CFR 98.233(n), if the flow rate and composition of the AGR or NRU stream routed to the flare is determined using a calculation method in 40 CFR 98.233(d), then reporters will be required to provide the information in amended 40 CFR 98.236(d)(1) and (2). In a related amendment, because gas routed to a flare will be calculated and reported as flared emissions and not vented emissions, we are revising the definition of ''acid gas removal unit (AGR) vent emissions'' to remove the phrase ''or a flare,'' so that it includes only those acid gas emissions released to the atmosphere.

Finally, after consideration of public comments regarding the inconsistent calculation of emissions from AGRs with vapor recovery systems compared to the treatment of emissions routed to vapor recovery systems for other source categories, the EPA is adding provisions for AGR vents routed to vapor recovery systems to final 40 CFR 98.233(d)(11) and correspondingly removing the existing (now redundant) provisions in current 40 CFR 98.233(d)(11) that direct reporters to adjust emissions downward to account for CO_2 emissions recovered and transferred outside the facility. For AGRs and nitrogen removal units with vents routed to vapor recovery systems and flares, the final provisions in 40 CFR 98.233(d)(11) specify how to account for emissions during periods when emissions from those vents are released directly to the atmosphere instead (*i.e.,* the vapor recovery system or flare is bypassed). These final provisions are similar to the final provisions for dehydrators routed to vapor recovery systems or flares. Reporters will be required to indicate whether the vent was routed to a vapor recovery system, and if so, whether it was routed for the entire year or only part of the year in 40 CFR 98.236(d)(1)(iv); we are correspondingly removing the existing (now redundant) provisions in current 40 CFR 98.233(d)(1)(iv) to report whether CO_2 emissions were recovered and transferred outside the facility. Similar to the reporting for AGRs routed to an engine or flare, AGRs routed to a vapor recovery system for the entire year report the information in amended 40 CFR 98.236(d)(1) except for the calculation method and the CO_2 and CH_4 emissions from the unit. If the AGR is routed to a vapor recovery system only for part of the year, the other information in amended 40 CFR 98.236(d)(1) is required to be reported for the part of the year in which emissions were vented directly to the atmosphere.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add reporting of CH_4 emissions from AGRs.

Comment: Commenters expressed concern about the accuracy of Calculation Method 3 for calculating CH4 emissions from AGRs, particularly equation W–4C, which relies on the AGR inlet and outlet flow rates and compositions. Commenters indicated that the volume of methane vented from AGRs is generally negligible when compared to the overall methane flow through the AGR, and the difference in methane concentration in the AGR inlet and outlet streams may be negligible. Consequently, using this method could potentially yield negative methane emissions values or otherwise inaccurate estimates.

Response: The EPA has considered the comments and agrees that there could be times when the normal variability in flow rate and concentration measurements could result in concerns with the accuracy of Calculation Method 3; however, the EPA does not find it appropriate to remove the ability to use Calculation Method 3 or equation W–4C in all cases. Therefore, in response to this comment, the EPA is finalizing the addition of a statement in 40 CFR 98.233(d)(3) to indicate that if the annual total volumetric emissions for an AGR or nitrogen removal unit vent calculated using Calculation Method 3 are less than or equal to 0 cubic feet per year, a reporter may not use this calculation method for that vent. Aside from this newly finalized restriction on Calculation Method 3, the existing rule allows reporters to choose between Calculation Method 3 or Calculation Method 4. Therefore, if the calculated emissions are greater than 0 cubic feet per year but the reporter is concerned that the results may not be accurate, the reporter may choose to use Calculation Method 4 instead, as provided by the existing rule.

Comment: Commenters noted that subpart W requires Calculation Method 2 if a vent meter is installed, which mandates quarterly sampling of the vented acid gas stream if a continuous gas analyzer is not installed, and asserted that the vent stream typically has high concentrations of H_2S and the sampling is therefore difficult and potentially dangerous to conduct. The commenters stated that, for other source types, including tanks and glycol dehydrators, the EPA has acknowledged that simulation software options are provided instead of direct measurement in part due to safety concerns with measurement (*e.g.,* high temperature of dehydrator vent streams). Commenters also indicated that some permits include modeling requirements for AGRs, similar to dehydrators, but if a vent meter is present on an AGR, subpart W mandates that reporters not use the modeling results, which is also inconsistent with the requirements for dehydrators. Commenters also provided information from published literature regarding the accuracy of simulation software for methane emissions. Commenters encouraged the EPA to allow the use of simulation software for AGR vents even if a vent meter is present.

Response: The EPA has reviewed this comment and the directives of CAA section 136 and determined it is appropriate to provide an allowance to use Calculation Method 4 for AGRs that have a vent meter and for which reporters are currently required to use Calculation Method 2. The EPA agrees that in cases where a vent stream has high concentrations of H_2S, there could be safety concerns with collecting the quarterly samples needed to determine the vent gas composition under Calculation Method 2. The EPA recognizes that part of the rationale for the structure and requirements for the original calculation methods is that use of a continuous vent meter to directly measure vent gas volumes was presumed to be more accurate than simulations with inputs based on ''engineering estimate and process knowledge based on best available data.'' However, based on our assessment of currently available information, in cases where a vent stream has high concentrations of H_2S, the EPA agrees that there could be safety concerns with collecting the quarterly samples needed to determine the vent gas composition under Calculation Method 2. Additionally, in this final rule, our assessment is that simulation software algorithms have improved since the original subpart W rulemaking in 2010 and furthermore the EPA is revising Calculation Method 4 as proposed to specify that certain simulation input parameters must be based on certain measurements, which do not have the same associated safety concerns (see section III.F.2. for further information on that revision). These factors should decrease the accuracy concerns between Calculation Methods 2 and 4. Finally, the EPA is also revising the reporting requirements for Calculation Method 4 to require additional verification information from the vent flow meter in such circumstances. The evaluation of the information available to the reporter though the vent flow meter could confirm or improve the results of simulations under Calculation Method 4 even further. If the simulations conducted under Calculation Method 4 do not agree with the measured annual volume of vent gas, then that could be an indication that the simulation results may not be an accurate representation of the emissions. For example, if a reporter conducts a single simulation for the reporting year and that single simulation results in an annual vent gas volume that varies significantly from the measured annual vent gas volume, the reporter could evaluate factors such as whether the simulation parameters are appropriately representative of annual operation or whether the operating parameters vary enough throughout the year that multiple partial-year simulations might better characterize the annual emissions.

Therefore, in summary, the EPA is finalizing an allowance for AGRs that have a vent meter to use Calculation Method 4. As part of the final provisions, the EPA is adding a new equation W–4D in 40 CFR 98.233(d) to determine the percent difference between the two vent gas volumes and new requirements to report both vent gas volumes (*i.e.,* the annual volume of vent gas measured with the vent meter and the simulated total annual volume of vent gas flowing out of the AGR) if Calculation Method 4 is used in 40 CFR 98.236(d)(2)(iii)(O). The final reporting requirements in 40 CFR 98.236(d)(2)(iii)(O) also specify that if the difference between the vent gas volumes is greater than 20 percent as calculated using equation W–4D, the reporter must provide a reason for that difference. As noted previously in this response, the EPA agrees that software simulations have improved and should generally be robust and accurate, and are thus consistent with CAA section 136(h), and also finds that the new information provided by reporters who elect to use Calculation Method 4 for an AGR with a vent flow meter installed will help to verify the data. The uncertainties in measurements provided by continuous vent flow meters are expected to be low (usually less than ±5 percent). The uncertainties in simulation results result from variability in the variety of input parameters that must be provided and uncertainties inherent in the equations built into the simulation flow rate; the overall uncertainty is more difficult to quantify due to the combination of these factors. The EPA considers the selected ±20 percent interval to be low enough to ensure reasonable agreement between the flow rates obtained by the different methods but high enough to reasonably account for the expected uncertainties. This interval is also consistent with an example scale provided in the GHG Protocol's ''Short Guidance for Calculating Measurement and Estimation Uncertainty for GHG

Emissions,'' in which uncertainties of ±15 percent are considered ''Good'' and uncertainties of ±30 percent are considered ''Fair.'' [48]

Comment: Commenters requested that the EPA revise subpart W to account for acid gas removal vents routed to vapor recovery systems, to be consistent with other emission source types. Commenters also noted that subpart W does allow reporters to subtract CO_2 emissions recovered from AGRs and transferred outside the facility, but it does not allow reporters to subtract the gas from AGR vent streams that are sent to acid gas injection wells or sequestered underground. The commenters stated that the EPA has previously stated that streams that are subsequently injected underground or geologically sequestered must be reported as emissions because the purpose of the GHG Reporting Program is to ''collect[] data to inform future climate change policies.'' [49] However, commenters asserted that this position is not consistent with the intent of the Inflation Reduction Act, so the EPA should amend subpart W to allow reporters to subtract the gas from AGR vent streams that are sent to acid gas injection wells or sequestered underground because those streams are not emitted to the atmosphere.

Response: As the commenters noted, the EPA's historic position on the issue of injection and sequestration for subpart W is outlined in *Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments:* ''In the final rule establishing the GHG Reporting Program (74 FR 56260, October 30, 2009), the EPA was clear that subpart methods and calculation procedures must be followed whether or not there is subsequent injection underground or geologic sequestration. The GHG Reporting Program is not an emissions inventory; rather it is a reporting program that collects data to inform future climate change policies. The same rationale applies to subpart W in this final action. Data on CO_2 from an acid gas recovery unit is needed by the EPA to inform future climate change policies, even if the CO_2 stream is subsequently injected underground. Therefore, such CO_2 streams must report for the AGR unit emission source.'' [50]

In August 2022, section 136 was added to the CAA. Section 136(c) of the CAA states that ''the Administrator shall impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W,'' and per CAA section 136(h), the emissions reported under subpart W of the GHGRP must ''accurately reflect the total methane emissions and waste emissions from the applicable facilities.'' While subpart W of the GHGRP will continue to be used ''to inform future climate change policies,'' due to the provisions in CAA section 136(h), the EPA must also revise reporting for subpart W to accurately reflect total emissions. Although the WEC will be imposed based on methane emissions, it is also important for CO_2 emissions to be accurate for purposes of comparing facility CO_2e emissions to the threshold in CAA section 136(c).

The EPA has also reviewed the requirements for other emission source types in subpart W and agrees with the commenters that for other emission sources, subpart W provides provisions specific to vapor recovery systems regardless of final disposition of the gas. Therefore, after further consideration, the EPA is finalizing provisions for AGR and nitrogen removal unit vents routed to vapor recovery that are similar to the provisions for dehydrators and atmospheric storage tanks routed to vapor recovery systems. The final provisions require the reporters to determine emissions from the vent prior to the vapor recovery system and then adjust those emissions to only report the emissions that are not recovered and are released directly to the atmosphere. These provisions will apply for all AGR vents routed to vapor recovery systems, regardless of whether the recovered gas is transferred outside the facility, injected underground, or sent elsewhere in the facility (*e.g.,* routed back to the process). Specifically, the EPA is amending 40 CFR 98.233(d) to remove the provisions related to CO_2 emissions recovered and transferred outside the facility in current 40 CFR 98.233(d)(9) and replace them with provisions for calculating the emissions vented directly to atmosphere from AGRs or nitrogen removal units routed to vapor recovery systems or flares in 40 CFR 98.233(d)(11). Similarly, the EPA is removing the requirement in current 40 CFR 98.236(d)(1)(iv) to report whether any CO_2 emissions from the acid gas removal unit were recovered and transferred outside the facility. The CO_2 emissions recovered and transferred outside the facility will continue to be reported under 40 CFR part 98, subpart PP (Suppliers of Carbon Dioxide) rather than subpart W, as currently required.

2. Calculation Method 4

The EPA is finalizing several revisions related to Calculation Method 4 for acid gas removal units as described in this section. The EPA received only minor comments regarding Calculation Method 4 for acid gas removal units. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

Reporters with AGRs that elect to calculate emissions using Calculation Method 4 are currently required to calculate emissions using any standard simulation software package that uses the Peng-Robinson equation of state and speciates CO_2 emissions. According to existing 40 CFR 98.233(c)(4), the information that must be used to characterize emissions include natural gas feed temperature, pressure, flow rate, and acid gas content; outlet natural gas acid gas content and temperature; unit operating hours; and solvent temperature, pressure, circulation rate, and weight. These parameters currently must be determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data. Consistent with section II.B. of this preamble, we are finalizing as proposed that the input parameters related to the natural gas feed that are used for the simulation software must be obtained by measurement. Those parameters include natural gas feed temperature, pressure, flow rate, acid gas content, CH_4 content, and, for nitrogen removal units, nitrogen content. We are finalizing as proposed that reporters collect measurements reflective of representative operating conditions over the time period covered by the simulation. We did not propose and are not finalizing any changes to the

[48] GHG Protocol Initiative. Short Guidance for Calculating Measurement and Estimation Uncertainty for GHG Emissions. Available at *https://ghgprotocol.org/sites/default/files/ghg-uncertainty.pdf* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[49] U.S. EPA, *Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments* at 1475 (Nov. 30, 2010). Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[50] U.S. *EPA, Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments,* November 2010, response to comment EPA–HQ–OAR–2009–0923–0582–31. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

requirement that the other parameters must be determined for operating conditions over the time period covered by the simulation based on engineering estimate and process knowledge.

We are also finalizing as proposed that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year. Under this change, reporters may continue to run the simulation once per year with parameters that are determined to be representative of operating conditions over the entire year. Alternatively, reporters will be allowed to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The reporter will then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run will be determined for the operating conditions over each corresponding portion of the calendar year. We note that parameter measurements used in a previous periodic simulation within the same reporting year may be used for subsequent simulations if they are representative of that parameter under the operating conditions of the subsequent simulation. Finally, we are finalizing as proposed the clarification that the information reported under 40 CFR 98.236(d)(2)(ii) should be provided on an annual basis, either as an average across the year, or a total for the year (in the case of operating hours for the unit).

We are also finalizing as proposed the replacement of the existing requirement to report solvent weight in existing 40 CFR 98.236(d)(2)(iii)(L) with a requirement in final 40 CFR 98.236(d)(2)(iii)(N) to report the solvent type and, for amine-based solvents, the general composition. Reporters must choose the solvent type option from a pre-defined list that most closely matches the solvent type and, for amine-based solvents, the general composition, used in their AGR. The standardized response options will include the following: ''Selexol™,'' ''Rectisol®,'' ''Purisol™,'' ''Fluor Solvent'' ''Benfield™,'' ''20 wt% MEA,'' ''30 wt% MEA,'' ''40 wt% MDEA,'' ''50 wt% MDEA,'' and ''Other (specify).'' In the event that reporters use more than one type of solvent in their AGR during the year, as proposed, the final reporting requirement specifies for reporters to select the option that corresponds to the solvent used for the majority of the year. The EPA expects that this final amendment to collect standardized information about the solvent will result in more useful data that will improve verification of reported data and better characterize AGR vent emissions, consistent with section II.C. of this preamble. It will also improve the quality of the data reported compared to the apparently inconsistent application of the current requirements by reporters.

3. Reporting of Flow Rates

The EPA is finalizing several revisions related to Calculation Method 4 for acid gas removal units as described in this section. The EPA received only supportive comments regarding the revisions to flow rate reporting for acid gas removal units. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

We are finalizing as proposed several amendments to improve the quality and verification of AGR flow rate information, consistent with section II.C. of this preamble. Reporters are currently required to report the total feed rate entering the AGR in units of million cubic feet per year (existing 40 CFR 98.236(d)(1)(iii), proposed 40 CFR 98.236(d)(1)(iv)). The existing rule does not specify million standard cubic feet per year or million actual cubic feet per year, so reporters may provide this feed rate in either of those units of measure. Therefore, we are first finalizing the proposal to require that the total annual feed rate that is required to be reported for all AGRs regardless of the how the emissions are calculated (existing 40 CFR 98.236(d)(1)(iii), amended 40 CFR 98.236(d)(1)(iv)) must be reported at standard conditions (*i.e.,* in units of MMscf per year). Second, we are finalizing as proposed the requirement to report the temperature and pressure that correspond to the flow rates reported for Calculation Methods 1, 2, or 3 (reporters using Calculation Method 4 are already required to report the temperature and pressure of the acid gas feed, under existing 40 CFR 98.236(d)(2)(iii)(B) and (C)). The additions, at 40 CFR 98.236(d)(2)(i)(D) and (E) and (d)(2)(ii)(I), (J), (L), and (M), specify that reported temperature and pressure must be the actual temperature and pressure if the flow rate is reported in actual conditions, or standard temperature and pressure if the flow rate is reported in standard conditions. The EPA received only supportive comments on these additions.

G. Dehydrator Vents

1. Selection of Appropriate Calculation Methodologies for Glycol Dehydrators

a. Summary of Final Amendments

The EPA is finalizing revisions to the calculation methodologies for glycol dehydrators largely as proposed, except for one update from proposal after consideration of comments.

We are finalizing as proposed the revised calculation requirements of 40 CFR 98.233(e) to allow reporters the ability to use Calculation Method 1 or Calculation Method 2 when determining emissions from dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 MMscf per day. After consideration of comments, we are finalizing the conditions under which a facility is required to use 40 CFR 98.233(e) with a modification. The proposed requirement stated that if reporters conduct modeling for environmental compliance or reporting purposes, including but not limited to compliance with Federal or state regulations, air permit requirements, or annual inventory reporting, or internal review, they would use those results for reporting under subpart W. Based on consideration of public comment concerning the nature of modeling for internal review purposes by facilities, and differences in program requirements, we are not finalizing the proposed requirement to use the results from such modeling for reporting under subpart W. We are instead requiring in the final provisions that if a facility is required to use a software program for compliance with federal or state regulations, air permit requirements or annual emissions inventory reporting that meets the requirements of 40 CFR 98.233(e)(1), they must use 40 CFR 98.233(e)(1) for reporting under subpart W. We anticipate that modeling consistent with the methodology outlined in 40 CFR 98.233(e)(1) could be conducted by reporters for environmental compliance or reporting purposes or reporters may run a simulation solely for the purpose of reporting under subpart W. This will ensure that the facility is able to use modeling results that are representative of actual operating conditions and meet the requirements of 40 CFR 98.233(e)(1) without requiring that models completed for other purposes meet the requirements under this subpart. As noted in the preamble to the proposed rule, we expect that these revisions will improve the quality of the data collected. For this reason and consistent with section II.B. of this preamble, we are requiring that facilities that are already completing modeling for other required reporting must use modeling to report to subpart W. The EPA is also finalizing as proposed the revisions to 40 CFR 98.236(e) to specify the applicable reporting requirements based on the selected calculation method rather than the throughput of the dehydrator. This amendment will improve the quality of the data collected, consistent with section II.B. of this preamble.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed selection of calculation methodologies for glycol dehydrators.

Comment: One commenter reported that simulations are run for ''internal review'' for a variety of purposes, including ''what-if'' scenarios (*i.e.,* exploring possible engineering adjustments), and may not meet the EPA's goal of estimating emissions based on operating conditions. The commenter recommended that only simulations run for compliance purposes should be used.

Response: We agree with the commenter that simulations run for other purposes may not result in emissions estimations based on representative operating conditions, as facilities may complete models for a variety of purposes, including models to consider future adjustments to the operation of the unit that are based on possible future, not actual, operating conditions. We are not finalizing the proposed requirement that all results from simulations run for the purposes of ''internal review'' or modeling completed for environmental compliance or reporting purposes are required to be used for reporting. We are instead requiring in the final provisions that if a facility performs emissions modeling of a glycol dehydrator for compliance with federal or state regulations, air permit requirements or annual emissions inventory reporting using a software program that meets the requirements of 40 CFR 98.233(e)(1), they must also use 40 CFR 98.233(e)(1) for reporting under subpart W. We expect that these amendments as finalized will increase the quality of data collected without requiring the inclusion of results from inappropriate modeling runs. We have revised the language in 40 CFR 98.233(e) introductory text to clarify these requirements.

Comment: One commenter requested clarification on whether reporters are compelled to use the simulation(s) from other compliance programs that may have different requirements, or if reporters can (or must) run a new simulation with an analysis pulled during the reporting year.

Response: We are not finalizing the proposed requirement to use all the results from modeling, that may have been performed for programs with different requirements, for reporting under subpart W. We are instead requiring in the final provisions that if a facility performs emissions modeling of a glycol dehydrator for compliance with federal or state regulations, air permit requirements or annual emissions inventory reporting using a software program that meets the requirements of 40 CFR 98.233(e)(1), they must also use 40 CFR 98.233(e)(1) for reporting under subpart W. We anticipate that modeling consistent with the methodology outlined in 40 CFR 98.233(e)(1) could be conducted by reporters for environmental compliance or reporting purposes, or reporters may run a simulation for the purpose of reporting under subpart W. We have revised the language in 40 CFR 98.233(e) introductory text to clarify these requirements.

2. Controlled Dehydrators

a. Summary of Final Amendments

The EPA is finalizing revisions to controlled dehydrator requirements largely as proposed, except for two clarifications from proposal in the final provisions after consideration of comments.

We are finalizing as proposed revisions to the methodologies for calculating emissions from dehydrator vents controlled by a vapor recovery system, flare, or regenerator firebox/fire tubes currently provided in 40 CFR 98.233(e)(5) and (6), respectively. The new language in 40 CFR 98.233(e)(4) provides a methodology for calculating emissions vented directly to the atmosphere during periods of time when emissions are not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes. For flared dehydrator emissions, the 40 CFR 98.233(e) provisions direct reporters to the methodologies in 40 CFR 98.233(n). As a regenerator firebox/fire tubes does not meet the definition of a flare per 40 CFR 98.238, we are finalizing methodologies as proposed for calculating combusted emissions from a regenerator firebox/fire tubes in 40 CFR 98.233(e)(5) using the combustion source equations W–39A, W–39B, and W–40 of 40 CFR 98.233(z)(3). We are also finalizing as proposed new reporting requirements for dehydrator units with emissions routed to a firebox/fire tubes in 40 CFR 98.236(e)(1)(xvi) and (xvii), (e)(2)(v), and (e)(3)(vii) that are consistent with the reporting requirements for combustion sources in 40 CFR 98.236(z)(2). By finalizing these amendments, the EPA enhances the overall quality of the data collected under the GHGRP, consistent with sections II.B. and II.D. of this preamble.

The EPA is also finalizing revisions as proposed to two terms consistent with the amendments for reporting for glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 MMscf per day. The EPA is finalizing 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. We are also finalizing as proposed the removal of the term ''reboiler'' from the definition of ''dehydrator vent emissions'', as the term ''regenerator'' refers to the same piece of equipment. Finally, we are finalizing expansion of the dehydrator control types referenced in the definition of ''dehydrator vent emissions'' to include regenerator fireboxes/fire tubes and vapor recovery systems. Additionally, the EPA is finalizing the amended definition of ''vapor recovery system'' in 40 CFR 98.6 to clarify that routing emissions from a dehydrator regenerator still vent or flash tank separator vent to the regenerator firebox/fire tubes does not qualify as vapor recovery for purposes of 40 CFR 98.233. Based on consideration of commenter feedback, the EPA is also finalizing two clarifications from proposal in the final provisions. We are amending from proposal the final text in 40 CFR 98.233(e)(4)(i) to clarify that reporters must calculate the emissions that would potentially be emitted if the vapor recovery system, flare, or regenerator firebox/fire tubes was not present as a first step. We are also finalizing an amendment to make the language in 40 CFR 98.233(e) introductory text consistent with the final requirements in 40 CFR 98.233(e)(4). In finalizing these edits, the EPA will improve the quality of the emissions data reported and confirm the original intent of these terms.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to the reporting requirements for controlled dehydrators.

Comment: One commenter requested the removal of the requirement in 40

CFR 98.233(e)(4)(i) to calculate the ''maximum potential annual vented emissions.'' The commenter noted that the requirement conflicts with the requirements that simulations should ''represent the operating conditions.'' The commenter noted that determining a maximum potential case requires assuming worst-case conditions, which does not reflect actual operations and does not further the EPA's goal of accurately determining emissions.

Response: The EPA agrees with the commenter that emissions need to be determined based on operating conditions. The intent was not for reporters to calculate the emissions that the dehydrator has the potential to emit based on worst-case conditions; the intention was for reporters to calculate the emissions that would potentially be emitted if the vapor recovery system, flare, or regenerator firebox/fire tubes was not present, as the first step in the process of calculating emissions that are vented directly to the atmosphere during periods of time when emissions are not routed to that device. The EPA has amended text from proposal in final 40 CFR 98.233(e)(4)(i) to clarify this intent.

Comment: One commenter noted that the 40 CFR 98.233(e) introductory text implies that uncontrolled emissions are calculated and then adjusted downward. The commenter stated that proposed 40 CFR 98.233(e)(4) directs reporters to calculate only those proposed emissions directly vented to the atmosphere. The commenter recommended that the EPA revise the 40 CFR 98.233(e) introductory text to remove the reference to adjusting emissions downward.

Response: The EPA agrees with the commenter that the reporter must calculate only emissions directly vented to the atmosphere. The language in 40 CFR 98.233(e) introductory text is consistent with the current requirements in 40 CFR 98.233(e)(5) for dehydrators with vapor recovery, but it was inadvertently not adjusted in the proposal to match the proposed requirements in 40 CFR 98.233(e)(4). The EPA is finalizing an amendment to the language in 40 CFR 98.233(e) introductory text consistent with the final requirements in 40 CFR 98.233(e)(4).

3. Calculation Method 1 for Glycol Dehydrators

a. Summary of Final Amendments

The EPA is finalizing revisions to the Calculation Method 1 for glycol dehydrators largely as proposed, except for three clarifications and updates from proposal after consideration of comment.

We are finalizing that reporters would collect measurements of the simulation input parameters listed under 40 CFR 98.233(e)(1) consistent with section II.B. of this preamble, with one change from the proposal The final parameters required to be measured include feed natural gas water content, wet natural gas temperature and pressure at the absorber inlet, and wet natural gas composition. The proposal also included a requirement to measure feed natural gas flow rate. However, after consideration of comments received, in an effort to reduce burden on reporters, we are not finalizing the requirement to directly measure feed natural gas flow rate; instead, we are requiring that feed natural gas flow rate must be determined based on measured data. For example, facilities may determine the feed natural gas flow rate based on measured outlet natural gas flow; we expect that this method determining feed natural gas flow rate to be accurate and less burdensome for facilities by using existing instrumentation. Requirements for measurement frequency for 40 CFR 98.233(e)(1)(i), (ii), (x) and (xi) are being finalized as proposed; for these input parameters, where parameters are determined to be representative of operating conditions over the entire year, the measurements must be taken at least once per year or where the measurements are only reflective of representative operating conditions over shorter time periods the measurements must be taken multiple times per year. However, given the significant burden noted by commenters to sample composition each reporting year, the EPA is finalizing a reduced frequency schedule for composition sampling and analysis (40 CFR 98.233(e)(1)(xi)). Reporters must sample and analyze composition at least once every five years. We are clarifying in the final rule that if physical or operational changes are made such that the measured sample is no longer representative of operating conditions, reporters must collect a new sample and re-analyze composition. We are requiring that samples must be collected within six months of the startup of production or by January 1, 2030 (*i.e.,* within five years of the effective date of the rule), whichever date is later and at least once every five years thereafter. Until such time that a sample can be collected, reporters may continue to determine these parameters by using one of the existing methods. We believe that samples taken at this frequency will be sufficiently representative as we do not expect significant changes except in cases where physical or operational changes, (*e.g.,* increased TEG circulation rate) are made.

We are also finalizing as proposed that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year. Under this change, reporters could continue to run the simulation once per year with parameters that are determined to be representative of operating conditions over the entire year. Alternatively, reporters would be allowed to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The reporter will then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run will be determined for the operating conditions over each corresponding portion of the calendar year. In the case of more than one simulation covering the reporting period, the reported parameter is the average of the parameters for each simulation. Finally, we are finalizing a clarification that the information reported under 40 CFR 98.236(e)(1) should be provided on an annual basis, either as a total for the year (in the case of operating hours for the unit and emissions) or as an average across the year (for all other input parameters).

We are finalizing as proposed the addition of ProMax as an example software program for calculating dehydrator emissions per 40 CFR 98.233(e)(1) for clarity for reporters. Consistent with the EPA's approval of ProMax for NESHAP HH compliance, the EPA is finalizing as proposed the requirement that if reporters elect to use ProMax, they will be required to use version 5.0 or above.

In order to assess potential emissions changes between reporting years, the EPA is also finalizing the addition of a new provision under 40 CFR 98.236(e)(1)(xviii) to request reporting of the modeling software used to calculate emissions for each dehydrator unit using Calculation Method 1. These amendments will improve the quality of the data collected, consistent with section II.B. of this preamble.

The EPA is finalizing as proposed under 40 CFR 98.236(e) the requirement to separate reporting of emissions for a modeled glycol dehydrator's still vent and flash tank vent. These amendments will improve the quality of the data collected, consistent with section II.C. of this preamble.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the Calculation Method 1 for glycol dehydrators.

Comment: Two commenters noted that the proposed requirement to measure feed natural gas flow rate is impractical, would require significant investment, and does not increase data quality. The commenters noted that facilities are not equipped with meters upstream of the dehydration unit, but gas flow is measured at the unit outlet. The commenters recommend that feed natural gas flow rate be determined based on measured data.

Response: After further consideration, the EPA is not finalizing the proposed requirement to measure the feed natural gas flow rate as our assessment is that there are other measurements that could be used to determine the feed natural gas flow rate that would have similar data quality. The EPA is instead requiring that reporters determine the feed natural gas flow rate based on measured data, which could include facility discharge meters or wellhead meters. Our assessment is that this will allow the use of existing instrumentation and also decrease burden, while maintaining data quality.

Comment: One commenter requested clarification on the proposed measurement frequency of model input parameters. The commenter also requested that even for multiple simulations a re-collection of parameters only be required upon suspected changes. The commenter noted that an operator can conduct one simulation on an annual basis using one set of parameters collected by the operator. Additionally, an operator may conduct periodic simulations. The commenter stated that conducting periodic simulations assists an operator in ensuring that it fully complies with the regulations in a timely manner that allows for any potential errors to be addressed in subsequent simulations. The commenter stated that the EPA disincentives periodic simulations by requiring an operator to perform field measurements to establish the parameters for every simulation.

Response: We are clarifying in the final rule that the frequency of measurement for the input parameters at for 40 CFR 98.233(e)(1)(i), (ii) and (x) must be measured at least once per year, but the measurement may be used in simulations covering different portions of the calendar year if the measurement is reflective of operating conditions over the time period of the simulation. After consideration of comment, the EPA is also finalizing a reduced frequency schedule from that proposed for the measurement of composition. Reporters must sample and analyze composition at least once every 5 years. Additionally, input parameters must be remeasured if no longer representative of operating conditions; for example, if physical or operational changes are made that may result in an increase in CH_4 or CO_2 emissions, reporters must collect and analyze a new sample. After consideration of the burden noted by commenters to collect samples within one year of finalization of the rule, the EPA is allowing 5 years from the date of publication of this final rule, or within 6 months of the startup of production, whichever date is later, for reporters to collect a composition sample. Until a sample is collected, facilities may use the existing methods. We believe that measurements taken at this frequency will be sufficiently representative of operating conditions as we do not expect significant changes except in cases where physical or operational changes (*e.g.,* increased TEG circulation rate) are made.

Comment: One commenter requested clarification on the reporting requirements for the inputs to the simulation. The commenter noted that 40 CFR 98.233(e)(1) requires reporters to ''collect measurements reflective of representative operating conditions for the time period covered by the simulation'' but 40 CFR 98.236(e)(1) requires reporting as an ''annual average.'' The commenter noted that ''annual average'' implies a different standard than ''measurements reflective of representative operating conditions.''

Response: The EPA agrees with the commenter that the reporter must collect measurements reflective of representative operating conditions. The EPA updated the final 40 CFR 98.236(e)(1) to clarify that in the case of more than one simulation covering the reporting period, the data reported is to be either the total (in the case of operating hours or emissions) and the average of the inputs to each simulation for all other input parameters.

4. Calculation Method 2 for Glycol Dehydrators

The EPA is finalizing revisions to the Calculation Method 2 reporting requirements for glycol dehydrators as proposed. The EPA received only supportive comments regarding the revisions to Calculation Method 2 for glycol dehydrators. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

Specifically, the EPA is finalizing as proposed the clarification 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 finalizing as proposed clarification in 40 CFR 98.236(e)(2) introductory text that the count of dehydrators in existing 40 CFR 98.236(e)(2)(i) (amended 40 CFR 98.236(e)(2)(ii)) 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 will improve implementation and verification of reported data, consistent with section III.C. of this preamble.

The EPA is finalizing as proposed revisions to the data collected under current 40 CFR 98.236(e)(2)(iii) (amended 40 CFR 98.236(e)(2)(iv)) to emphasize the original intent of the rule. We are finalizing as proposed the requirement to specifically state that the reporting of ''other'' control devices should only include control devices that reduce CO_2 and/or CH_4 emissions. This final revision will allow the EPA to verify the expected reductions in vented CO_2 and/or CH_4 emissions due to the use of the control device. This final amendment will improve implementation and verification of reported data, consistent with section III.C. of this preamble.

5. Desiccant Dehydrators

a. Summary of Final Amendments

The EPA is finalizing revisions to the reporting requirements for desiccant dehydrators in 40 CFR 98.236(e) largely as proposed, except for three clarifying corrections and updates from proposal after consideration of comment. The EPA also is finalizing related changes to definitions of ''dehydrator'' and ''desiccant'' in 40 CFR 98.6 as proposed.

Specifically, we are finalizing removal of the cross-references from 40 CFR 98.236(e)(3) to 40 CFR 98.236(e)(2)(i) through (iv) and instead are including all of the applicable reporting requirements from current 40 CFR 98.236(e)(2)(i) through (iv) for desiccant dehydrators under 40 CFR 98.236(e)(3). Replicating the requirements under 40 CFR 98.236(e)(3) will make the rule easier to follow and allow the EPA to further clarify the required reporting data elements for desiccant dehydrators. One clarifying correction that is being finalized consistent with public comment is removal of the proposed reference to flash tanks in 40 CFR 98.236(e)(3)(vii)(B), which was referenced in error. A second clarifying correction that is being finalized consistent with public comment is all proposed references to regenerator firebox/fire tubes in 40 CFR 98.236(e)(3) have been replaced with references to non-flare combustion units as commenters noted that desiccant dehydrators are not known to have configurations with regenerator firebox/fire tubes. The final rule also includes conforming changes in 40 CFR 98.233(e)(5) to specify procedures for calculating emissions from non-flare combustion units used with desiccant dehydrators that are the same as the procedures for calculating emissions from regenerator fireboxes/fire tubes that are used with small glycol dehydrators.

The EPA also is finalizing as proposed the addition of four new desiccant dehydrator reporting data elements in 40 CFR 98.236(e)(3), we are not finalizing one proposed reporting element, and we are finalizing as proposed the removal of reporting the total count of desiccant dehydrators at the facility as required in 40 CFR 98.236(e)(3)(i) of the existing rule. The four new data elements are the total volume of all opened desiccant dehydrator vessels in 40 CFR 98.236(e)(3)(iii), the total number of desiccant dehydrator openings in the calendar year in 40 CFR 98.236(e)(3)(iv), the count of opened desiccant dehydrators that used deliquescing desiccant (*e.g.,* calcium chloride or lithium chloride) in 40 CFR 98.236(e)(3)(ii)(A) (proposed 40 CFR 98.236(e)(3)(ii)(B)), and the count of opened desiccant dehydrators that used regenerative desiccant (*e.g.,* molecular sieves, activated alumina, or silica gel) in 40 CFR 98.236(e)(3)(ii)(B) (proposed 40 CFR 98.236(e)(3)(ii)(C)). The proposal also included a requirement to report the total count of opened desiccant dehydrators in 40 CFR 98.236(e)(3)(ii)(A). However, to eliminate duplicative reporting requirements, we are not finalizing the requirement to report the total count of opened desiccant dehydrators, as we will have the information through the sum of the opened dehydrators using deliquescing desiccant and the opened dehydrators using regenerative desiccant. After removing the data element for the total count of opened desiccant dehydrators, the two new reporting data elements for the count of opened desiccant dehydrators that used deliquescing desiccant and the count of opened desiccant dehydrators that used regenerative desiccant have been moved to 40 CFR 98.236(e)(3)(ii)(A) and (B) in the final amendments. These amendments will improve verification of reported data and ensure accurate reporting of emissions, consistent with section II.C. of this preamble.

The EPA is also finalizing revisions to the definitions of ''dehydrator'' and ''desiccant'' in 40 CFR 98.6 as proposed. In the definition of ''dehydrator,'' we are finalizing the change to replace the word ''absorb'' with ''remove,'' and we are finalizing the change to clarify that desiccant is not a type of liquid absorbent. In the definition of ''desiccant'' we are finalizing the change to include ''molecular sieves'' in the list of example desiccants and we are finalizing the change to clarify that desiccants include, ''but are not limited to,'' molecular sieves, activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. We expect these amendments will improve the overall quality and completeness of the emissions data collected by the GHGRP, consistent with section II.A. of this preamble.

b. Summary of Comments and Responses on Desiccant Dehydrators

This section summarizes the major comments and responses related to the proposed amendments to reporting requirements for desiccant dehydrators.

Comment: One commenter noted that references to ''regenerator firebox/fire tubes'' throughout the desiccant dehydrator reporting requirements in 40 CFR 98.236(e)(3) appear to be a mistake because the commenter is not aware of desiccant dehydrators that route emissions to regenerator firebox/fire tubes. The commenter suggested that references to non-flare combustion calculations may be more appropriate. The commenter also noted that 40 CFR 98.236(e)(3)(vii)(B) should be changed to remove the reference to flash tanks because flash tanks are used only with glycol dehydrators, not desiccant dehydrators.

Response: We agree with the commenter that regenerator firebox/fire tubes are not used with desiccant dehydrators. Regenerator firebox/fire tubes are used with glycol dehydrators to provide the energy needed to drive water out of rich glycol to produce lean glycol for recirculation to the absorber, but they are not needed in the operation of desiccant dehydrators. The current rule requires reporting of combusted emissions from dehydrator emission streams that are routed to a flare or regenerator firebox/fire tubes. Since regenerator firebox/firetubes are not needed for operation of desiccant dehydrators, it is possible that all combustion emissions reported for desiccant dehydrators under subpart W are from flares. However, to allow for the possibility that some emissions from desiccant dehydrators may be routed to a regenerator firebox/fire tubes for a glycol dehydrator at the same site, and to allow reporting of combusted emissions from thermal oxidizers or other types of combustion devices, we are replacing the proposed references to regenerator firebox/firetubes in 40 CFR 98.236(e)(3) in the final rule provision with references to ''non-flare combustion unit.'' This change will allow complete and accurate reporting of all combusted emissions from desiccant dehydrators.

We also agree with the commenter that the proposed reference to flash tanks in the desiccant dehydrator reporting requirements is incorrect. Flash tanks reduce the pressure of the rich glycol stream out of the absorber for a glycol dehydrator, thereby separating a significant portion of the high vapor pressure compounds, such as methane, from the liquid glycol upstream of the regenerator; flash tanks are not applicable for desiccant dehydrators. Thus, after considering both this comment and the one above, the reporting requirement in 40 CFR 98.236(e)(3)(vii)(B) of the final rule was changed from proposal to read as follows: ''Total volume of gas routed to non-flare combustion units, in standard cubic feet.''

Comment: One commenter stated that the EPA should eliminate reporting elements that are duplicative of other data it is already collecting and that simply add steps to reporters without any additional information to be gained. As an example, the commenter cited the proposed requirement in 40 CFR 98.236(e)(3)(ii)(A) to report the total number of opened desiccant dehydrators, which should be equal to the sum of the total number of opened desiccant dehydrators that used deliquescing desiccant in proposed 40 CFR 98.236(e)(3)(ii)(B) plus the total number of opened desiccant dehydrators that used regenerative desiccant in proposed 40 CFR 98.236(e)(3)(ii)(C).

Response: After consideration of public comment to eliminate duplicative reporting requirements, we are not finalizing the proposed requirement to report the total count of opened desiccant dehydrators because this quantity can be calculated as the sum of the reported count of opened dehydrators using deliquescing desiccant plus the reported count of opened dehydrators using regenerative desiccant and is, therefore, redundant.

H. Liquids Unloading

1. Summary of Final Amendments

The EPA is finalizing several changes to calculation methods and the reporting requirements for liquids unloading. These changes are expected to improve data quality while recognizing the operational challenges that facility operators can face in the field when managing unloading events, including monitoring and measuring emissions from those events.

Consistent with section II.C. of this preamble, we are clarifying the proposal that required reporters to calculate and report emissions when natural gas emissions from well venting for liquids unloading are routed to the atmosphere or to a control device, recognizing that some reporters may choose to flare or use natural gas at the well-pad. In the final rule, we are narrowing this to require reporting of liquids unloading emissions when natural gas is vented to the atmosphere or to a flare because use in other combustion equipment on-site will be captured by the combustion source. We have expanded, as proposed, the type of unloading from just plunger lift or non-plunger lift unloadings to also include a designation of whether each unloading event is a manual or automated unloading. Therefore, there are now four unloading types: automated plunger lift, manual plunger lift, automated non-plunger lift and manual non-plunger lift. The EPA proposed and is finalizing this requirement to more accurately characterize emissions from liquids unloading. In addition to changes to 40 CFR 98.233(f) and 98.236(f), we are finalizing as proposed definitions in 40 CFR 98.238 for ''Manual liquids unloading'' and ''Automated liquids unloading.''

The EPA is finalizing further clarifying changes to liquids unloading calculation methods in 40 CFR 98.233(f)(2) after consideration of public comment to more accurately calculate emissions from liquids unloading. For Calculation Method 2, the definition of CD_p, casing diameter, is amended in the final rule to clarify that CD_p can also include the tubing diameter when stoppage packers have been placed downhole in the annulus, forcing unloadings to travel to the surface through the tubing string rather than the annulus. The definition of WDp, well depth, for Calculation Method 2 is also amended in the final rule to clarify that well depth may be measured from either the bottom of the well or the top of the fluid column. This has a direct bearing on the first part of equation W–8, which estimates the quantity of natural gas in the production column that will be initially emitted when the well is unloaded. Reporters are not required to determine the top of the fluid column, but allowing reporters to have the option to define the top of the liquid column and establish that depth as the bottom of the well recognizes that the available capacity in the wellbore to hold accumulated gas volumes is displaced by liquids and results in more accurate emissions measurements. Although some natural gas may be entrained in the liquid column, the volume of gas is likely to be very small compared to volume of gas in the borehole above the liquid column. Additionally, liquids from the unloading are expected to be directed to an atmospheric tank or separator where gas emissions from gas entrained in the liquids will be reported in the tanks source under 40 CFR 98.233(j). If the reporter is unable to determine the top of the fluid column or chooses not to do so, the reporter must assume that well depth is the bottom of the well. We are finalizing a similar clarifying change to the definition of well depth in the calculation requirements for Calculation Method 3 for the same reasons.

For well depth in Calculation Method 2, we are also finalizing a clarification in defining the bottom of the well for horizontal wells, to be the point at which the borehole pivots downhole from vertical to horizontal. Horizontal wells produce gas along one or more horizontal laterals directing flow from the producing formation through the cased hole to the production string at the base of the vertical portion of the well. Unloadings are required when wells, primarily gas wells, accumulate liquids in the wellbore, and velocity up the production tubing is not sufficient to lift liquids to the surface. The well is effectively shut-in and ceases production until the liquids are lifted and gas flow is restored. Horizontal laterals are perforated at varying intervals and liquids accumulation in a horizontal well will generally occur first in the horizontal portion of the well because that is where gas with entrained liquids will enter the production string. Eventually liquids will accumulate throughout the horizontal lateral to the base of the vertical section of the well or even closure to the surface. This change recognizes that it is very likely that a horizontal well requiring an unloading will have liquids accumulation from the top of the fluid column at the bottom of the vertical portion of the well downhole through the extent of the horizontal portion of the well. We are, therefore, allowing reporters using Calculation Method 2 for non-plunger unloadings to consider the bottom of the well for a horizontal well to be the point at which the vertical borehole pivots to a horizontal direction. This change only affects Calculation Method 2. The bottom of the well in Calculation Method 3 is defined as tubing depth to the plunger bumper, which is generally at the bottom of the vertical portion of a well.

We are also finalizing amendments in 40 CFR 98.233(f) and 98.236(f) that recognize that some reporters may direct natural gas emissions from liquids unloading to flare stacks. Prior to this rulemaking, natural gas emissions from unloadings were assumed to be from venting the unloadings. Based on review of public comment submitted to the EPA in response to the proposed amendments from June 2022, we understand that some reporters may be considering directing emissions to a flare stack or other control device. Therefore, in the proposal for this rulemaking, we included regulatory text to require reporting of emissions and other data if natural gas flow from a liquids unloading is directed to a flare or control device. We are finalizing provisions in 40 CFR 98.233(f) directing reporters to use the calculation methods in 40 CFR 98.233(n) for flare stacks to calculate associated unloading emissions from flaring and report these emissions under 40 CFR 98.236(n). If natural gas from unloadings is directed to other control devices, the emissions should be calculated as part of that source (*e.g.,* through the combustion source type) under the 40 CFR 98.233 provisions for those source types.

With respect to Calculation Method 1, the EPA proposed to require use of this method to calculate emissions for each well at least once every 3 years. Calculation Method 1 requires that a reporter record an average flow rate at a representative well by placing a recording flow meter on the vent line from the well to an atmospheric tank, separator or other device to vent the gas. The flow rate may be applied to other wells in the same sub-basin/unloading type/pressure-diameter combination. Therefore, the EPA's proposal would have required reporters to measure a representative well in each sub-basin at least once every 3 years. We received many comments suggesting the requirement was overly burdensome and unrealistic given the operational, logistical, and technical challenges of placing flow meters on the vent lines to so many wells. Unloadings are not steady state events, and the variability of flow in an unloading event can also impact the accuracy of measurement using a single flow meter as there will often be a large expulsion of gas at the initiation of the unloading followed by a quickly declining emission rate until gas begins flowing again to the sales line or other flow line. After consideration of public comment and given the challenges with flow measurement discussed above, the EPA is not finalizing the proposed requirement to use Calculation Method 1 to measure a representative well in each sub-basin at least once every 3 years in this final rule. Instead, the EPA is retaining the existing requirement that allows reporters to choose Calculation Method 1 as an option over the engineering equations in Calculation Methods 2 and 3. In doing so we encourage reporters to use measured data in Calculation Method 1 where feasible. However, we are confident that use of the engineering equations in Calculation Methods 2 and 3 provides accurate estimates of emissions from unloadings because inputs to the equations are based on well-specific empirical data including casing and tubing diameter, well depth, shut-in or line pressure, the flow line rate of gas, and the time the well is left open for venting. Furthermore, the additional granularity of reported data including all data inputs to the equations and disaggregated reporting at the well level will allow for more thorough verification by the EPA of reported data.

Although the final rule does not require use of Calculation Method 1 at least once every three years, the rule retains the existing requirement that reporters electing to use Calculation Method 1 must calculate a new average flow rate every other calendar year starting with the first calendar year of data collection.

The EPA is also finalizing as proposed revisions to 40 CFR 98.236(f)(1) and (2) to require the reporting of certain data elements that are included in existing equations W–8 and W–9 for Calculation Methods 2 and 3 when calculating emissions from unloadings but which were previously not reported. For Calculation Method 2, for wells without plunger lifts, reporting of the following additional data elements will now be required: well depth (WD_p), the average flow-line rate of gas (SFR_p), the hours that wells are left open to the atmosphere during unloading events ($HR_{p,q}$), and the shut-in, surface or casing pressure (SP_p). For Calculation Method 3, required reporting for wells with plunger lifts will now include the additional following data elements: tubing depth (WD_p), the flow-line pressure (SP_p), the average flow-line rate of gas (SFR_p), and ($HR_{p,q}$). Requiring reporting of these data elements will improve verification of annual reports to the GHGRP and will allow the EPA and the public to replicate calculations and more confidently confirm reported emissions than is currently possible.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to liquids unloading.

Comment: The EPA received comments asserting that the proposed rule language that requires Calculation Method 1 every 3 years is unnecessary and burdensome and will not lead to more accurate reporting. Commenters also requested that the EPA allow an operator that uses direct measurement in the first year to use the data obtained from that first-year direct measurement in calculating emissions in subsequent years (*i.e.,* years 2 and 3). One commenter further asserted that the EPA did not consider the Allen et al. (2015) study that directly measured emissions from liquids unloading.[51] Commenters stated that knowing which wells will require and how often they require liquids unloading venting is not predictable or consistent. Commenters stated that when unloadings are needed is variable and does not necessarily occur every 3 years. Commenters also suggested that placement of a flow meter on the vent line will result in unacceptable back-pressure on the well, effectively defeating the purpose of an unloading, which is to relieve back pressure on the well. One commenter also noted that the EPA does not require operators under NSPS OOOOb to install a flow meter for liquids unloading venting. One commenter provided anecdotal evidence from an operator, based on placement of flow meters at 12 wells, that doing so caused significant operational problems at the wells. Commenters requested that the EPA instead continue to allow use of the engineering equations in Calculation Methods 2 and 3, remove the proposed requirement to use Calculation Method 1 every 3 years, and retain Calculation Method 1 as an option for calculating emissions from liquids unloading.

Response: The EPA acknowledges that there can be challenges associated with installing, operating, and monitoring flow meters on well-pads. Liquid unloadings are not typically steady state events. Back pressure on the vent line could result from use of orifice flow meters with orifice cross-sections that are unable to manage highly variable flow rates, especially following an initial surge of liquids from the early stage of unloading. Back pressure can be alleviated by changing out the orifice plates. However, we acknowledge that this can be technically challenging in cases where unloading events are subject to highly variable flow rates and/or in cases when the occurrence of unloading events is not predictable. The EPA does note that Allen et. Al. in their 2015 study on liquids unloading, placed flow meters on the vent lines to tanks and did not report any back pressure or impediments to the vent line.

We agree with the commenters that robust engineering equations for liquids unloadings can provide reasonable estimates of emissions if all unloading events are recorded accurately and all inputs to engineering equations are recorded and reported accurately. In addition, the additional new reporting requirements for unloadings in this final rule require all data elements in equations W–8 and W–9 to be reported, allowing for more thorough verification of reported emissions. Given these considerations, the EPA is not finalizing the proposed requirement to use Calculation Method 1 every 3 years. Instead, Calculation Method 1 will remain an option for reporters, who may choose between the three robust Calculation Methods under the final rule. Should a reporter elect to use Calculation Method 1, the reporter must comply with the existing requirement to calculate a new average flow rate every other calendar year starting with the first calendar year of data collection. For a new producing sub-basin category, the reporter must calculate an average flow rate beginning in the first year of production.

The EPA agrees that operators are not required to install a flow meter under NSPS OOOOb; however, we note that program and this program have complimentary but not identical goals. As such, the EPA disagrees with the commenter's assertion that the lack of a requirement for flow meters under the NSPS on its own would be justification for not requiring measurement of liquids unloading events under subpart W.

[51] Allen, D.T., *et al.,* 2015. ''Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings.'' *Eviron. Sci. Technol.* 49, 641-648. *https://pubs.acs.org/doi/10.1021/es504016r.* Available in the docket for this rulemaking, Docket ID. No. EPA-EQ-OAR-2023-0234.

The Allen et. Al. study measured emissions from liquids at 107 wells in four producing regions in the U.S. The study noted that measured emissions at wells with plunger lift unloadings exceeded calculated emissions using equation W–9. Conversely, emissions at wells with non-plunger lift unloadings using equation W–8 were greater than emissions measured by study. The conclusion of the study was that the GHGRP nationwide total unloading emissions and the study's nationwide estimate extrapolated from the 107 wells in the study were roughly equivalent. Although the study found some variance between the results of the engineering equations used for liquids unloading in the GHGRP and the measurements taken in the field, the EPA believes the relative consistency of nationwide results confirms the adequacy of the equations. In addition, the new reporting requirements that further differentiate the type of unloading between manual and automated plunger lift and non-plunger lift unloadings and the required reporting of all data elements in equations W–8 and W–9 will result in more effective use of, and accurate results from, the engineering equations.

Comment: Commenters supported the proposed revisions to add reporting requirements for liquids unloading events, including whether the unloading event is automatic or manual, specific flow-line and tubing depth data, and the hours that wells are left open during unloading events. However, commenters suggested that the EPA clarify that reporting for unloading events should only apply when the gas is vented directly to the atmosphere or routed to a control device to improve clarity for reporters and provide greater context for the reported emissions for the EPA. Other commenters requested clarification on what constitutes a control device.

Response: The EPA acknowledges the commenters' support for the new reporting requirements for liquids unloading and is finalizing those requirements largely as proposed. Additionally, the EPA agrees with the commenter's recommendation to include language that clarifies that only gas vented directly to the atmosphere or routed to a flare should be reported and is finalizing language to this effect.

The EPA proposed to limit the calculation and reporting of emissions to unloadings that vented directly to the atmosphere or to a control device because it is those unloadings that release greenhouse gas emissions. After further consideration, the EPA is retaining this language in the final rule but is changing the proposed ''control device'' reference to flares to be more specific. It is possible that some natural gas from unloading events is routed to other types of control devices, but emissions from these events will be covered under those other sources (*e.g.,* the combustion source). Although we do not expect large volumes of natural gas to be directed to flares given the purpose, nature and duration of unloading events, there may be some instances of flaring gas off an unloading, and the EPA believes it is important to capture these emissions. The final rule in 40 CFR 98.233(f) directs reporters who flare natural gas from unloadings to calculate emissions using the calculation methods in 40 CFR 98.233(n), Flare Stacks and report those emissions under 40 CFR 98.236(n).

Comment: The EPA received comments recommending that it consider revising the definition of Casing Diameter (CD_p) in equation W–8 to ID_p (Internal Diameter) to allow the application of either tubing diameter if the well is equipped with tubing string and no plunger lift, or casing diameter if the well does not have tubing and plunger lift. According to the commenter, it is common practice for operators to first install a tubing string to increase flow velocity and install a plunger lift later when the well undergoes production decline. The commenter stated that the diameter that is used in the equation should be the diameter of the portion of the well that is vented, whether venting the casing, tubing, or both. The commenter also recommended that the EPA should clarify that the well depth is based only on the vertical depth for horizontal wells. The commenter stated that the volume of liquid should not be considered gas that is vented, and rather only the depth above the fluids should be used to quantify the vented gas.

Response: The EPA recognizes that operators may place stoppage packers in the annulus of some wells, thereby removing the potential for gas lift in the annulus so that the gas lift occurs in the tubing string. Therefore, the EPA is amending the definition of CD_p in this final rule to address the use of stoppage packers. The definition of CD_p in the final rule states that it means, ''Casing internal diameter for well, p, in inches or the tubing diameter for well, p, when stoppage packers are used in the annulus to restrict flow of gas up the annulus to the surface.'' We disagree, however, with the recommendation to revise the definition of casing diameter in equation W–8 to internal diameter (ID_p) because there could be gas lift in the annulus between the casing and the tubing string.

The EPA also agrees with the commenter that the depth should be based on the vertical depth for horizontal wells. In most cases, the horizontal portion of the well is very likely to be filled with liquids from the end of the well bore up to at least the pivot point when the horizontal hole pivots to vertical. While we acknowledge that horizontal wells are very rarely truly horizontal through the well-bore, and there is a possibility that some small quantities of gas may exist in the non-vertical portion of the well-bore, these are likely to be limited cases. The vertical portion of the well bore is where the gas column will be mostly located. Horizontal wells produce gas along one or more horizontal laterals directing flow from the producing formation through the cased hole to the production string at the base of the vertical portion of the well. Unloadings are required when wells, primarily gas wells, accumulate liquids in the wellbore, and velocity up the production tubing is not sufficient to lift liquids to the surface; the well is effectively shut-in and ceases production until the liquids are lifted and gas flow is restored. Horizontal laterals are perforated at varying intervals along the lateral and liquids accumulation in a horizontal well will generally occur first in the horizontal portion of the well because that is where gas with entrained liquids enters the production string. Eventually liquids are likely to accumulate throughout the horizontal lateral to the base of the vertical section of the well or even closer to the surface. In the final rule, we have modified the definitions for well depth in equation W–8 to add clarifying language allowing reporters using Calculation Method 2 for non-plunger unloadings to consider the bottom of the well for a horizontal well to be the point at which the vertical borehole pivots to a horizontal direction. This change recognizes that it is very likely that a horizontal well requiring an unloading will have liquids accumulation from the top of the fluid column at the bottom of the vertical portion of the well downhole through the extent of the horizontal portion of the well. We do not believe the additional language is necessary for equation W–9. The bottom of the well in Calculation Method 3 is defined as tubing depth to the plunger bumper and the bumper will normally be at the vertical base of the well.

Regarding well depth and the fluid column, the final rule allows for reporters to consider the fluid column depth in equations W–8 and W–9. More specifically, for wells where the fluid column extends above the bottom of the well, well depth may be measured from the top of the fluid column and this change is made in the definition of WD_p in equations W–8 and W–9 in the final rule. This is optional for reporters and if they do not use the top of the fluid column, they must consider the well depth to extend to the bottom of the vertical portion of the well in equation W–8 for Calculation Method 2 and to the plunger bumper in equation W–9 for Calculation Method 3. The EPA is finalizing the rule with this option because we understand that the available capacity to hold accumulated gas volumes below the top of the fluid level in the wellbore is displaced by liquids. Allowing reporters to consider the top of the fluid column to be the bottom of the well in these instances will result in more accurate emissions measurements. The EPA acknowledges that in some cases small volumes of gas may be entrained in the liquids. The entrained gas will separate from the liquids at a separator or atmospheric tank downstream of the well and the entrained gas emissions are subject to reporting in the hydrocarbon liquids and produced water storage tanks source under 40 CFR 98.233(j). The proposed definition for WD_p in W–8 was ''Well depth from either the top of the well or the lowest packer to the bottom of the well, for well, p, in feet.'' In the final rule, we have added additional clarifying language so that the final definition reads, ''Well depth from either the top of the well or the lowest packer to the bottom of the well or to the top of the fluid column, for well, p, in feet. For horizontal wells the bottom of the well is the point at which the vertical borehole pivots to a horizontal direction.'' In equation W–9, the definition for well depth, WD_p, in the final rule is ''Tubing depth to plunger bumper or to the top of the fluid column for well, p, in feet.''

I. Gas Well Completions and Workovers With Hydraulic Fracturing

1. Summary of Final Amendments

The EPA is finalizing certain revisions to calculation and reporting requirements in 40 CFR 98.233(g) and 98.236(g) for completions and workovers with hydraulic fracturing with several notable changes from the proposed requirements.

To calculate emissions from this source, reporters must use equation W–10A or W–10B. Both equations are designed to calculate the volumes of gas produced during the initial flowback, or pre-separation, stage and during the separation stage when sufficient quantities of gas are available to flow to a separator until the well moves to production. Flow rates in the separation stage are measured or calculated, but flow rates in the initial flowback period are currently based on a calculation assuming the gas flow rate in the initial stage is one half the gas flowrate at the beginning of the separation stage. Consistent with section II.B. of this preamble, the EPA is finalizing a change to equations W–10A and W–10B to allow use of multiphase flow meters to measure gas flow rates during the initial flowback stage as an alternative to assuming the flowrate is one half the flow rate at the beginning of separation. Reporters may choose either option to calculate the produced gas volume during the initial separation stage. To include measurement with multiphase flow meters as an option, the final rule includes minor changes from those proposed to equations W–10A and W–10B in 40 CFR 98.233(g) to allow reporters to choose either option, use of the original assumption of a flow rate that is half the flow rate at the beginning of separation or a measured flow rate using the multiphase meter. In addition, although we proposed removing the engineering equations to calculate flow rates for gas well completions, equations W–11A for sub-sonic flow and W–11B for sonic flow, following review and consideration of public comment, we are retaining these equations. The EPA is finalizing this change to the calculation methods in 40 CFR 98.233(g) from proposal to allow use of calculated flow rates for gas well completions using engineering equations only if it is not possible to measure the flow rate for use in equations W–10A and W–10B.

The EPA is finalizing the rule to add reporting requirements in 40 CFR 98.236(g) to ensure consistency with requirements for the determination of gas flow volumes and gas composition in the flare stack emissions source. As discussed elsewhere in this preamble, the EPA is finalizing calculation and reporting requirements for natural gas emissions routed to the flare stacks from multiple sources. Reporters routing gas to a flare from hydraulically fractured completions and workovers must calculate CH_4, CO_2 and N_2O emissions according to the calculation methods in 40 CFR 98.233(n), Flare stacks. Determination of gas flow volumes using continuous parameter monitoring systems is specified in 40 CFR 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and determination of gas composition use continuous gas composition analyzers or gas sampling is specified in 40 CFR 98.233(n)(4). If the reporter does not use continuous flow measurements, the reporter must calculate natural gas emissions routed to the flare using the calculation methods in 40 CFR 98.233(g) as specified in 40 CFR 98.233(n)(3)(ii)(B).

In addition, the EPA is finalizing changes to reporting requirements in 40 CFR 98.236(g) from the proposal. In the final rule, reporters are required to indicate how the flow during the initial flowback period was determined. More specifically, reporters must indicate whether the flow rate during the initial flowback period was determined using a recording flow meter (digital or analog) at the beginning of the separation, using a multiphase flow meter or using one of the engineering equations, W11–A or W–11B. If a multiphase flowmeter was used to measure the flow rate during the initial flowback period, reporters are required to report the average flow rate measured by the multiphase flow meter from the initiation of flowback to the beginning of the period of time when sufficient quantities of gas present to enable separation in standard cubic feet per hour. We are also finalizing reporting requirements in 40 CFR 98.236(g) that require reporters to indicate whether the flow rate measured during the separation stage was measured using a using a recording flow meter (digital or analog) installed on the vent line or calculated through use of engineering equations W–11A or W–11B. In addition, we are finalizing proposals to add reporting of additional identifiers for completion and workover well type combinations, notably whether the well is flared or vented and whether or not it is a reduced emission completion or workover.

As discussed above, the EPA is not finalizing the proposed removal of engineering equations W–11A and W–11B, the choke flow equations, which can be used with equation W–10A as an option to calculate back flow rates at gas well completions and workovers with hydraulic fracturing. The EPA had proposed removing this option, which allows reporters to use the engineering equation to calculate a flow rate for gas well completions and workovers rather than measuring the flow rate. Following receipt of comment and after further consideration, the EPA understands there may be situations in the field where measurement may not always be possible (for example, when a meter fails, if safety is at risk or for some other operational reason). In the 2023 Subpart W proposal, we explained that if we ultimately retained the choke flow equation, we planned to amend the reporting requirements in the final rulemaking to improve data quality and transparency. Therefore, we have added a new reporting requirement in 40 CFR 98.236(g) to require reporters that use equation W–10A to indicate whether the backflow rate for the representative well is measured using a flow meter or calculated using equations W–11A or W–11B. Under the existing regulations, reporters using equation W–10A to calculate emissions from gas well completions and workovers do not state in their annual GHGRP reports whether the emissions were calculated using a measured flow rate at the representative well or were calculated using the choke flow equations, equation W–11A or W–11B. Although this provides the EPA with an understanding of how many wells use a representative well as the basis to calculate emissions, we do not have any clarity on the number of wells that use the choke flow equations to calculate the gas flow rate for the representative wells versus those that use a measured flow rate at the representative wells. We believe reporting these data improves data quality by helping the EPA better understand how many reporters use the choke flow equations, the number of wells with completions and workovers with emission calculations based on choke flow equation measurements and the associated emissions. These additional data elements will provide the EPA with a better understanding of the bases for the reported emissions, which will improve the EPA's ability to verify the reported data and, ultimately, improve the accuracy of emissions.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to gas well completions and workovers with hydraulic fracturing.

Comment: Several commenters stated that existing methodologies for calculating emissions from oil and gas well completions and workovers with hydraulic fracturing are not based on empirical data, in particular when estimating emissions during the initial flowback period.

Response: The EPA disagrees with the commenters that proposed methodologies were not based on empirical data. The equations in 40 CFR 98.233(g) used to calculate emissions from these sources rely on empirical data measured for the well, including measured flowback flow rates at the start of separation and throughout the separation stage. The EPA acknowledges that equations W–10A and W–10B assume the average flow rate is one half of the flow rate at the beginning of separation, but we emphasize that the pre-separation flow rate is still calculated based on a measured separation flow rate. In addition, as described in the summary of final amendments for this source and later in this comment and response section, the EPA is finalizing revisions to the rule to allow use of multiphase flow meters during the initial pre-separation stage as an option to directly measure gas flow rates through the full initial flowback period. We intend to continue to assess alternatives for determining gas flow rates and flow volumes during the pre-separation stage.

The current rule includes equations W–11A and W–11B, the choke flow equations, which are engineering equations that provide an option for calculating flow rates at gas wells when direct measurement is not possible. This final rule will continue to include these equations (as discussed later in this comment and response section) but we note that they also rely on well-specific and empirical data, such as the pressure upstream and downstream of the choke.

Comment: The EPA received a comment with a suggestion to allow use of multiphase flow meters to measure backflow rates prior to the separation stage. The commenter stated that multiphase flow meters can measure oil, gas, and water without the need for separation and that, therefore, they are capable of measuring flowback from the beginning of flowback to the separation stage.

Response: The commenter suggested use of a flowmeter upstream of the separator to measure flow rates during the initial flowback period to complement the existing use of flow meters downstream of the separator to measure flow rates once separation is possible, which is consistent with the purpose of the proposed amendments to add empirical methods to the provisions and a potential refinement of the existing calculation methodology to improve data quality. The EPA acknowledges that use of multiphase meters is growing in the oil and gas industry. In addition, given that current methodologies rely on gas flow rates metered during the separation stage to estimate the flow rate during the initial flowback period, the EPA agrees that using multiphase meters to directly measure the initial flowback period flow rates should improve the accuracy of emission estimates during the initial flowback period under the existing methodology. We are, therefore, amending 40 CFR 98.233(g) to include use of average flow rate measurements from multiphase flow meters as an option for calculating natural gas emissions during the initial flowback period. Correspondingly, in the final provisions the EPA is also finalizing changes to reporting requirements in 40 CFR 98.236(g) to require reporters to indicate whether they used a multiphase flow meter to calculate emissions from completions and workovers with hydraulic fracturing. Under the final provisions in 40 CFR 98.233(g), reporters may either use the assumption that the initial flowback rate is one half of the flowrate at the beginning of separation or use flow rates measured with a multiphase meter. While the EPA recognizes that multiphase metering upstream of a separator could potentially be used to extrapolate downstream flow rates, this would require complex modeling of the change in the thermodynamic state of the fluid between upstream and downstream conditions and an assumed separation efficiency to quantify the gas flow downstream of the separator. Therefore, after considering this and that use of a multiphase meter is a new approach to quantifying emissions from completions and workovers, when metering of the gas flow during the separation period is required under the final provisions, the EPA is continuing to require use of a flowmeter downstream of the separator even if a multiphase meter is placed upstream of the separator.

Comment: The EPA received comments requesting to retain equations W–11A and W–11B, the choke flow equations, noting that these equations are used by reporters and further stating that the EPA provided no rationale as to why it proposed to remove this calculation option other than it is not used that often. In addition, several commenters also suggested that the EPA should consider allowing use of a Gilbert-type equation to be used to calculate gas flow rates. One commenter recommended that the EPA evaluate the use of a Gilbert-type equation while another commenter suggested replacing the existing choke flow equations with a Gilbert-type equation.

Response: In the 2023 Subpart W Proposal, we proposed removing equations W–11A and W–11B altogether, thus requiring use of measured flow rates at hydraulically fractured completions and workovers. Based on further consideration, including of the public comments we received, we recognize that field conditions, operating conditions, or health and safety considerations may preclude the use of flow meters to measure back flow rates in certain cases. Therefore, the EPA is retaining the existing choke flow equations, W–11A and W–11B, as an option in the final rule.

The EPA is finalizing the rule without the addition of the Gilbert-type equation. We only proposed and sought comment on whether to remove the existing engineering equations; therefore, the suggestion to finalize the rule with a new engineering equation is outside the scope of this rulemaking. However, we thank the commenters for their suggestion and we may consider the equation in a future rulemaking.

We note that inputs to the equations are based on well-specific measurements for the orifice cross section, temperature, and pressure upstream and downstream of the choke. However, the EPA expects that flow rates determined based on direct measurements to be more accurate. Therefore, the rule is finalized to specify that the engineering equations can only be used when the reporter is unable to place a flow meter on the line to a vent or flare.

Finally, in the final rule, we have added a new reporting requirement in 40 CFR 98.236(g) to require reporters that use equation W–10A to indicate whether the backflow rate for the representative well is measured using a flow meter or calculated using equation W–11A or W–11B.

J. Blowdown Vent Stacks

1. Summary of Final Amendments

Subpart W currently requires reporting of blowdowns either using unique physical volume calculations by equipment or event types (40 CFR 98.233(i)(2)) or using flow meter measurements (40 CFR 98.233(i)(3)). The EPA is finalizing as proposed, consistent with section II.D. of this preamble, 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. Final 40 CFR 98.233(i)(2)(iv) includes separate paragraphs for each set of equipment and event type categories and provides clearer information regarding the applicable requirements for each industry segment.

The EPA is finalizing as proposed revisions to the descriptions of the facility piping and pipeline venting categories, which were previously in 40 CFR 98.233(i)(2) and are now in the new 40 CFR 98.233(i)(2)(iv), to reflect the EPA's intent regarding which equipment or event type category is appropriate for each blowdown, consistent with section II.D. 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. In contrast, 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. Additionally, we are finalizing as proposed the removal of the reference to ''distribution'' pipelines in the description of these two categories because we did not intend to limit the pipeline venting category to unique physical volumes that include such pipelines. Finally, we note that for the ''facility piping'' equipment category and the ''pipeline venting'' equipment category, the existing phrase ''located within a facility boundary'' in the descriptions of those categories generally refers to being part of the facility as defined by the existing provisions of subpart A or subpart W, as applicable, and we are not finalizing and did not propose to change that portion of those descriptions.

We are finalizing as proposed the extension of 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 aligns the requirements for the two geographically dispersed industry segments currently required to report blowdown vent stack emissions (Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting) and increases clarity of reporting requirements for Onshore Natural Gas Transmission Pipeline industry segment reporters, consistent with section II.D. of this preamble. As described in section III.C.1. of this preamble, we are also finalizing as proposed the use of engineering estimates to determine the temperature and pressure for emergency blowdowns in equation W–14A for the geographically dispersed industry segments that will begin reporting emissions from blowdown vent stacks (Onshore Petroleum and Natural Gas Production and Natural Gas Distribution).

As we explained at proposal, 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 are finalizing as proposed to add provisions to equation W–14B of 40 CFR 98.233(i)(2)(i) to allow use of engineering estimates to determine the temperature and pressure of an emergency blowdown for both the geographically dispersed industry segments that currently report blowdown vent stack emissions (Onshore Natural Gas Transmission Pipeline and Onshore Petroleum and Natural Gas Gathering and Boosting) as well as the geographically dispersed industry segments that will be required to begin reporting blowdown vent stack emissions as described in section III.C.1. of this preamble (Onshore Petroleum and Natural Gas Production and Natural Gas Distribution), consistent with equation W–14A. Additional minor technical corrections for clarity associated with the blowdowns vent stack source are described in table 3 in section III.V. of this preamble.

After consideration of public comments, we are also finalizing additions to 40 CFR 98.236(i)(1) to specify how to assign blowdowns to a well-pad site or gathering and boosting site if a blowdown event is not directly associated with a specific well-pad or gathering and boosting site or could be associated with multiple well-pad or gathering and boosting sites. The final provisions direct reporters to associate the blowdown with either the nearest well-pad or gathering and boosting site upstream from the blowdown event or the well-pad or gathering and boosting site that represented the largest portion of the emissions for the blowdown event, as appropriate.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to blowdown vent stacks.

Comment: One commenter stated that the EPA is proposing to require site-level details regarding blowdowns and recommended that the EPA instead allow reporters to aggregate events by type. The commenter stated that aggregating events by type would avoid line-by-line reporting per event and greatly reduce the complexity of reporting for the source category, without impacting data quality or transparency. The commenter also noted that some blowdowns such as mid-field pipeline blowdowns are not associated with a given well-pad or gathering station, so reporting those pipelines by site could be challenging. The commenter suggested allowing those types of blowdown events to be aggregated by county, which is consistent with other pipeline reporting under PHMSA.

Response: The EPA did not propose and is not taking final action in this rule to require individual blowdown reporting. The EPA did propose, and is finalizing, reporting of certain emission source types by well-pad site or gathering and boosting site, as described further in section III.D. of this preamble. To implement those provisions, the EPA is finalizing as proposed the additional requirement to report a well-pad ID or gathering and boosting site ID for blowdowns at facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, respectively, so that blowdown event reporting in these industry segments is aggregated by equipment or event type at each well-pad site or gathering and boosting site for facilities, as appropriate. To further clarify this in the final provision, the EPA is moving the requirement to report the equipment or event type from the introductory text of 40 CFR 98.236(i)(1) to a separate reporting element in 40 CFR 98.236(i)(1)(ii).

Regarding the concern with reporting a site for mid-field pipeline blowdowns or other similar circumstances, in the final provisions, the EPA has provided guidance in 40 CFR 98.236(i)(1) and (2) to assist with these kinds of determinations. The final provisions direct reporters to associate the blowdown with either the nearest well-pad or gathering and boosting site upstream from the blowdown event or the well-pad or gathering and boosting site that represented the largest portion of the emissions for the blowdown event, as appropriate. This approach for reporting is more appropriate for the final rule than a county-based approach because very little data will be reported on a county (or sub-basin) basis with the changes in reporting levels described in section III.D. of this preamble. Further, it is similar to the established approach for assigning blowdowns and emissions to an equipment or event type when a blowdown event results in emissions from multiple equipment or event types.

K. Atmospheric Storage Tanks

1. Open Thief Hatches

a. Summary of Final Amendments

The EPA is finalizing several amendments regarding thief hatch monitoring on atmospheric storage tanks. These revisions to the atmospheric tank calculation methodologies and reporting requirements will help quantify the impact of open thief hatches on atmospheric storage tank emissions and enhance the overall quality of the data collected under the GHGRP, consistent with section II.B. of this preamble.

The EPA is finalizing as proposed revisions to 40 CFR 98.233(j)(4) that specifically state that emissions vented directly to the atmosphere during times of reduced control system capture efficiency are required to be calculated. Reduced capture efficiency may occur during periods when the control device is not operating or is not effectively capturing emissions, such as when thief hatches are open or due to other causes such as open pressure relief devices.

We are also finalizing as proposed the calculation methodology in 40 CFR 98.233(j)(4) for determining reduced capture efficiencies when a control device is in use but a thief hatch is open. We are finalizing revisions to 40 CFR 98.233(j)(4)(i)(C) to require facilities to assume that no emissions are captured by the control device (0 percent capture efficiency) when the thief hatch on a tank is open, with one revision. After consideration of comments received, we are clarifying in 40 CFR 98.233(j)(4)(i)(C) that a thief hatch is open if it is fully or partially open such that there is a visible gap between the hatch cover and the hatch portal, as the EPA did not intend for leaks from an open thief hatch that are only identifiable using OGI technologies to be required to assume a capture efficiency of zero.

The EPA is finalizing the requirements of 40 CFR 98.233(j)(7) to require monitoring of the thief hatch with revisions from proposal. We are finalizing as proposed that if a thief hatch sensor is present and operating on the tank, sensor data must be used to inform the periods of time that a thief hatch is open. Regarding the proposed revision that the thief hatch sensor must be capable of transmitting and logging data whenever a thief hatch is open and when the thief hatch is subsequently closed, in the final provision we removed the requirement that the sensor be capable of transmitting data, in order to include use of sensor data in situations where the sensor has local logging capabilities but is not able to remotely transmit the data. Additionally, after consideration of comments, we are adding in the final provisions a requirement that if a thief hatch sensor is not operating but a tank pressure sensor is operating on a controlled atmospheric pressure storage tank, reporters must use data obtained from the pressure sensor to determine periods when the thief hatch is open. Similar to an applicable thief hatch sensor, an applicable operating tank pressure sensor must be capable of logging tank pressure data. It is expected that operators would assume that a pressure indication outside of normal operating range would indicate an issue with the thief hatch. Pressure indication is similar in accuracy as a visual inspection in the case of open thief hatches.

The EPA is finalizing the requirements in 40 CFR 98.233(j)(7) as proposed with revisions to clarify that if neither an applicable thief hatch sensor nor an applicable tank pressure sensor is operating on the controlled atmospheric storage tank, reporters must perform a visual inspection of each thief hatch on a controlled atmospheric storage tank. We are further clarifying in the final rule that visual inspections in accordance with 40 CFR 98.233(j)(7)(i) through (iii) must be performed for tanks equipped with thief hatch or pressure sensors during periods of time when the thief hatch or pressure sensor is not operating or malfunctioning for longer than 30 days. We feel that 30 days is a reasonable amount of time during which the facility can return the sensor back into service before triggering a visual inspection requirement to assure proper operation of the equipment. This is similar to the requirements for continuous flare pilot flame monitoring that requires a monthly visual inspection (which is the requirement in absence of continuous monitoring) if the continuous monitoring device is out of service for more than 4 weeks. We are finalizing 40 CFR 98.233(j)(7)(i) with a correction to an inadvertent error from proposal, requiring that if the thief hatch is required to be monitored as part of a cover or closed vent system, rather than to comply with requirements of 40 CFR 60.5397b, to comply with 40 CFR 60.5395b or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62 on a controlled atmospheric storage tank, visual inspections must be conducted at least as frequent as the required AVO inspection described in 40 CFR 60.5416b or the applicable EPA-approved state plan or the applicable Federal plan in 40 CFR part 62, or annually (whichever is more frequent). A similar correction is also being made to 40 CFR 98.233(j)(7)(ii). Additionally, we are removing the phrase ''fugitive emissions'' from 40 CFR 98.233(j)(7)(i) and (ii) as tank covers are not considered fugitive emission components under the updated cross-referenced provisions. We are finalizing the requirements in 40 CFR 98.233(j)(7)(ii) and (iii) as proposed, which require visual inspections once per calendar year, at a minimum, for tanks not equipped with thief hatch or pressure sensors and for tanks with malfunctioning thief hatch or pressure sensors. We are finalizing as proposed that if one visual inspection is conducted in the calendar year and an open thief hatch is identified, the reporter is required to assume that the thief hatch had been open for the entire calendar year or the entire period that the sensor(s) was not operating or malfunctioning if the visual inspection occurred during the period in which it was malfunctioning or not operating. If multiple visual inspections are conducted in the calendar year and an open thief hatch is identified, the reporter is required to assume that the thief hatch had been open since the preceding visual inspection (or the beginning of the year if the inspection was the first performed in a calendar year) through the date of the visual inspection (or the end of the year if the inspection was the last performed in a calendar year).

We are finalizing the reporting requirements for open thief hatches in 40 CFR 98.236(j) as proposed. We are finalizing the addition of 40 CFR 98.236(j)(1)(x)(F) to require reporting of the number of controlled atmospheric storage tanks with open thief hatches within the reporting year, as well as the addition of 40 CFR 98.236(j)(1)(xv) to require reporting of the total volume of gas vented through the open thief hatches, for Calculation Methods 1 and 2. We are finalizing similar requirements for atmospheric storage tanks with emissions calculated using Calculation Method 3 in 40 CFR 98.236(j)(2)(ii)(D) and (H) for hydrocarbon liquids tanks and 40 CFR 98.236(j)(2)(iii)(D) and (F) for produced water tanks.

We are finalizing the revisions in 40 CFR 98.233(j)(4)(i)(D) as proposed to require facilities to account for time periods of reduced capture efficiency from causes other than open thief hatches when determining total emissions vented directly to atmosphere based on best available data, with one clarification. As described for open thief hatches, the EPA understands that pressure monitoring data may be used to determine when a pressure relief device is open and venting to the atmosphere on a controlled atmospheric storage tank. Thus, the EPA is clarifying in 40 CFR 98.233(j)(4)(i)(D) that best available data may include, but is not limited to, data from operating pressure sensors on atmospheric pressure storage tanks. In cases where a pressure relief device is open, reporters must use pressure sensor data (if available) to assist in the determination of the duration of the release and use best available data to determine the reduction in capture efficiency.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to open thief hatches on atmospheric storage tanks.

Comment: Several commenters requested that the EPA provide a definition of an open or not properly seated thief hatch and clarify whether leaks that can only be identified through use of an OGI camera or similar detection technology do not meet the definition of an open or not properly seated thief hatch. Many commenters noted that it is inaccurate to assume a small, wisping leak only seen through an OGI camera would require an operator to assume 0 percent capture efficiency when most of the storage tank vapors remain in the tank, are captured, or are routed to a control device. Additionally, commenters noted that small leaks would not be identified with the proposed technology suggested by the EPA: thief hatch sensor or visual inspection monitoring methods.

Response: In the final rule, the EPA is removing from the proposed provisions the phrase ''not properly seated'' in 40 CFR 98.233(j)(4)(i)(C) through (D) and 40 CFR 98.233(j)(4)(ii) and instead specifying that a thief hatch is open if it is fully or partially open such there is a visible gap between the hatch cover and the hatch portal. The requirements to perform a visual inspection to identify a gap on applicable atmospheric storage tank thief hatches would not necessitate the use of OGI technologies to identify emissions. Thus, in this final rule, emissions from an open thief hatch that are only identifiable using OGI technologies would not be required to assume a capture efficiency of 0 percent but these emissions would still have to be quantified under 40 CFR 98.233(j)(4)(i)(D) based on best available data, including any data from operating pressure sensors on atmospheric pressure storage tanks. A visible gap creates a larger more direct path of emissions to the atmosphere, so we are maintaining the assumed a 0 percent capture efficiency for this case. While we are not requiring emissions that are only identifiable using OGI technologies to assume a capture efficiency of 0 percent, such emissions identified through OGI may still constitute a violation of emission standards under NSPS OOOOb or a state or federal plan implementing EG OOOOc.

We note that we may consider the option of incorporating thief hatches into the leak requirements in 40 CFR 98.233(q) and (r) in future rulemakings.

Comment: Many commenters requested that tank pressure sensors be acceptable to determine if tank thief hatches are open or not properly seated. One commenter stated that on controlled tanks, these sensors will register (for example) between 0.8 and 8 pounds of pressure. The commenter notes that a pressure indication outside of this range would indicate an issue with the thief hatch. Pressure indication could in fact be more accurate than a visual inspection in the case of a not properly seated thief hatch.

Response: The EPA agrees with the commenters that the use of pressure monitors on atmospheric storage tanks are appropriate for determining the duration of time a thief hatch is open. The EPA concurs with commenters that, on controlled tanks, pressure sensors will typically register within a normal operating range (*e.g.,* between 0.8 and 8 pounds of pressure). If a thief hatch is open, the tanks will not build up pressure. A pressure indication outside of the normal operating range would indicate an issue with the thief hatch and could be used to determine duration of a thief hatch opening. Thus, in the final rule, we are adding language to 40 CFR 98.233(j)(7) to include requirements for the use of pressure sensors on applicable atmospheric storage tanks with thief hatches. Specifically, we are adding language to specify that if a thief hatch sensor is not operating but a pressure sensor is present and operating on the tank, pressure sensor data must be used to inform the periods of time that a thief hatch is open. The thief hatch sensor must be capable of logging data whenever a thief hatch is open and when the thief hatch is subsequently closed. We agree that including requirements for the use of pressure sensor data for open thief hatch determinations as specified in the final provisions will improve the accuracy of reported emissions and incorporate empirical data.

Comment: One commenter noted that thief hatch sensors do periodically malfunction and may falsely indicate an open thief hatch. The commenter requested that the EPA allow reporters to exclude thief hatch sensor malfunction periods and instead use best available monitoring data (*e.g.,* TEMS, other parametric monitoring, last inspection) when determining the time that the thief hatch was open in calculating and reporting storage tank emissions.

Response: In the final rule, the EPA is finalizing that operators are required to use thief hatch sensors or pressure monitors where they are already installed and operating, which implies properly functioning equipment. As proposed, the EPA states in 40 CFR 98.233(j)(7) that thief hatch sensors (and in the final rule, pressure monitors) must be capable of logging data whenever the thief hatch is open. Thus, malfunctioning equipment would not meet these requirements and should not be used to determine periods of time when thief hatches are open. In the final rule, the EPA is further clarifying that during periods of time when the sensor is malfunctioning for periods greater than 30 days, facilities must perform visual inspections and determine thief hatch opening durations according to the methodologies in 40 CFR 98.233(j)(7)(i) through (iii).

2. Malfunctioning Dump Valves

a. Summary of Final Amendments

The EPA is finalizing as proposed revisions to the equation variables (particularly the subscripts) in equation W–16 to clarify the intent of this equation. Specifically, we are finalizing the change of 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), (2), and, if applicable, (j)(4). We are also finalizing the replacements of the ''n'' and ''o'' 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), (2), and, if applicable, (j)(4).

The EPA is finalizing the requirements of 40 CFR 98.233(j)(5)(i) to require monitoring of the gas-liquid separator liquid dump valve with revisions from proposal, consistent with section II.B. of this preamble. In the final rule, we are adding after consideration of comment that if a parametric monitor is present and operating on the tank or gas-liquid separator, then the parametric monitor data must be used to inform the periods of time that a dump valve is stuck in an open or partially open position as well as when the dump valve is subsequently closed. Similar to pressure sensors on thief hatches, it is expected that operators would assume that a parameter (*e.g.,* pressure, temperature, flow) indication outside of normal operating range would indicate an issue with the dump valve. Parameter indication is similar in accuracy as a visual inspection in the case of malfunctioning dump valves. We are also finalizing that the parametric monitor must be capable of logging data whenever a gas-liquid separator liquid dump valve is stuck in an open or partially open position and when the gas-liquid separator liquid dump valve is subsequently closed, which will allow reporters to accurately determine the time input for equation W–16 (T_{dv}).

The EPA is finalizing the requirement to perform routine visual inspections of separator dump valves to determine if the valve is stuck in an open or partially open position when an applicable parametric monitor is not present or is not operating, with a revisions from proposal that expands the inspections to also include audio and olfactory inspections. Audio, visual, and olfactory (AVO) inspections would be required once per calendar year, at a minimum. Similar to the provisions of 40 CFR 98.233(q) and 40 CFR 98.233(j)(7), if one AVO inspection is conducted in the calendar year and a stuck dump valve is identified, the reporter is required to assume that the dump valve had been stuck open for the entire calendar year. If multiple AVO inspections are conducted in the calendar year and a stuck dump valve is identified, the reporter is required to assume that the dump valve had been stuck open since the preceding AVO inspection (or the beginning of the year if the inspection was the first performed in a calendar year) through the date of the AVO inspection (or the end of the year if the inspection was the last performed in a calendar year). The EPA determined that this is an appropriate methodology as it is consistent with the inspection requirements for dump valves under 40 CFR 98.233(k).

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to malfunctioning dump valves on separators feeding on atmospheric storage tanks.

Comment: Many commenters requested that parametric monitoring be acceptable to determine if a gas-liquid separator liquid dump valve is stuck in an open or partially open position. Additionally, commenters noted that an effective approach to identify stuck dump valves involves auditory inspections of the tank, particularly in cases where tanks are designed with submerged fill—a stuck dump valve allowing gas flow into the tank produces noticeable ''bubbling'' sounds.

Response: The EPA agrees with the commenters that the use of parametric monitors on atmospheric storage tanks and gas-liquid separators are appropriate for determining the duration of time a gas-liquid separator liquid dump valve is stuck in an open or partially open position. The EPA concurs that, for operators of high-pressure gas-liquid separators, wells will be shut-in or there will be alarms requiring immediate response due to the separator reaching low liquid level, which will happen if a gas-liquid separator liquid dump valve is stuck in an open position. In other cases, operators will also monitor the density of the fluid going to the tank and alarms on low density will trigger follow up to inspect for a malfunctioning gas-liquid separator liquid dump valve. Thus, in the final rule, we are adding appropriate language to 40 CFR 98.233(j)(5)(i) to include the use of parametric monitors on applicable atmospheric storage tanks and gas-liquid separators. We agree that including use of parametric monitoring data to determine whether or not a dump valve is stuck open as specified in the final provisions will improve the accuracy of reported emissions and incorporate empirical data.

The EPA also agrees that, for those tanks and separators without a parametric monitor, auditory inspections should be used in conjunction with visual inspections to determine if a gas-liquid separator liquid dump valve is stuck in an open or partially open position. We agree that an effective approach to identify stuck gas-liquid separator liquid dump valves involves auditory inspections of the tank, particularly in cases where tanks are designed with submerged fill—a stuck dump valve allowing gas flow into the tank produces noticeable ''bubbling'' sounds. In the final rule, we are clarifying in 40 CFR 98.233(j)(5) that AVO inspections must be performed to determine if a gas-liquid separator liquid dump valve is stuck in an open or partially open position.

3. Applicability and Selection of Appropriate Calculation Methodologies for Atmospheric Storage Tanks

a. Summary of Final Amendments

The EPA is finalizing several revisions with regard to the applicability and selection of an appropriate calculation methodology for atmospheric storage tanks, consistent with sections II.B. and II.C. of this preamble. The EPA is finalizing revisions to the introductory text of 40 CFR 98.233(j) as proposed to add language that clearly states that the annual average daily throughput of hydrocarbon liquids should be based on flow out of the separator, well, or non-separator equipment determined over the actual days of operation. We are also finalizing certain changes to the introductory text in 40 CFR 98.233(j) as proposed, which amends the requirements in 40 CFR 98.233(j) to specify that reporters may use Calculation Method 1, Calculation Method 2, or Calculation Method 3 when determining emissions from atmospheric storage tanks receiving hydrocarbon liquids flowing out of wells, gas-liquid separators, or non-separator equipment with throughput greater than 0 barrels per day and less than 10 barrels per day. After consideration of comments, we are finalizing the conditions under which a facility is required to use 40 CFR 98.233(j)(1) with a modification. The proposed requirement stated that if reporters conduct modeling for environmental compliance or reporting purposes, including but not limited to compliance with Federal or state regulations, air permit requirements, or annual inventory reporting, or internal review, they would use those results for reporting under subpart W. Based on consideration of public comment concerning the nature of modeling for internal review purposes by facilities, and differences in program requirements, we are not finalizing the proposed requirement to use the results from such modeling for reporting under subpart W. We are instead requiring in the final provisions that if a facility is required to use a software program for compliance with federal or state regulations, air permit requirements or annual emissions inventory reporting that meets the requirements of in 40 CFR 98.233(j)(1), they must use 40 CFR 98.233(j)(1) for reporting under subpart W. We anticipate that modeling consistent with the methodology outlined in 40 CFR 98.233(j)(1) could be conducted by reporters for environmental compliance or reporting purposes or reporters may run a simulation solely for the purpose of reporting under subpart W. This will ensure that the facility is able to use modeling results that are representative of actual operating conditions and meet the requirements of 40 CFR 98.233(j)(1) without requiring that models completed for other purposes meet the requirements under this subpart.

We are finalizing the removal of the ''fixed roof'' language when referring to atmospheric pressure storage tanks subject to 40 CFR 98.233(j) as proposed. We are also finalizing revisions to 40 CFR 98.236(j)(1)(x) and 40 CFR 98.236(j)(2)(i) to require separate reporting of the total count of fixed roof and floating roof tanks at the facility. We are finalizing revisions of all instances of ''storage tanks,'' ''atmospheric tanks,'' and ''tanks'' in 40 CFR 98.233(j) and 40 CFR 98.236(j) to instead use the term ''atmospheric pressure storage tanks'' as proposed. We are finalizing the addition of a definition for an atmospheric pressure storage tank as proposed, which is defined as ''a vessel (excluding sumps) operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (*e.g.,* wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof.''

We are moving the last sentence of 40 CFR 98.233(j), which contains reference to ''paragraph (j)(4) of this section'' to be located prior to discussion of ''paragraph (j)(5) of this section'' so that paragraph references appear in the order in which they are contained in the regulatory text. Relatedly, we are also deleting the sentence immediately following discussion of ''paragraph (j)(5) of this section'' because it is largely duplicative of the moved last sentence of 40 CFR 98.233(j), as proposed.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to the application and selection of appropriate calculation methodologies for atmospheric storage tanks.

Comment: One commenter reported that simulations run for ''internal review'' for a variety of purposes, including ''what-if'' scenarios (*i.e.,* exploring possible engineering adjustments) may not meet the EPA's goal of estimating emissions based on operating conditions. The commenter recommended that only simulations run for compliance purposes should be used.

Response: We agree with the commenter that simulations run for other purposes may not result in emissions estimations based on representative operating conditions, as facilities may complete models for a variety of purposes, including models to consider future adjustments to the operation of the unit that are based on possible future, not actual, operating conditions. We are not finalizing the proposed requirement that all results from simulations run for the purposes of ''internal review'' or modeling completed for environmental compliance or reporting purposes are required to be used for reporting. We are instead requiring in the final provisions that if a facility performs emissions modeling for compliance with federal or state regulations, air permit requirements or annual emissions inventory reporting using a software program that meets the requirements of 40 CFR 98.233(j)(1), they must also use 40 CFR 98.233(j)(1) for reporting under subpart W. We expect that these amendments as finalized will increase the quality of data collected without requiring the inclusion of results from inappropriate modeling runs. We have revised the language in 40 CFR 98.233(j) introductory text to clarify these requirements.

4. Controlled Atmospheric Storage Tanks

a. Summary of Final Amendments

The EPA is finalizing the revisions to the methodologies for calculating controlled atmospheric storage tanks emissions vented directly to the atmosphere in 40 CFR 98.233(j)(4), consistent with section II.D. of this preamble. We are finalizing 40 CFR 98.233(j)(4)(i) with modifications from proposal. As proposed, the methodology under 40 CFR 98.233(j)(4)(i) for calculating emissions vented to the atmosphere during periods of reduced capture efficiency of the vapor recovery system or flare (*e.g.,* when a thief hatch is open or not properly seated or when a pressure relief valve is open) first required reporters to determine the maximum potential vented emissions as specified under 40 CFR 98.233(j)(1), (2), or (3) per 40 CFR 98.233(j)(4)(i)(A). In the final rule, the EPA is removing the term ''maximum potential'' from 40 CFR 98.233(j)(4)(i)(A); while this term was meant to signify that reporters should not reduce for controls at this step of the calculation, we understand that the terminology may have been confused for worst-case condition potential-to-emit (PTE) emissions. Thus, in the final rule, the EPA is adding language to 40 CFR

98.233(j)(4)(i)(A) to clarify consistent with our original intent.

The provisions for calculating recovered mass in 40 CFR 98.233(j)(4)(ii) are being finalized as proposed. For flared atmospheric storage tank emissions, the revisions to 40 CFR 98.233(j), which direct reporters to the methodologies in 40 CFR 98.233(n), are being finalized as proposed. While the final flaring provisions differ somewhat from the proposed provisions, as explained in more detail in section III.N. of this preamble, the final amendments generally specify as proposed that vented atmospheric storage tank emissions include only those emissions vented directly to the atmosphere and emissions routed to a flare are considered flare stack emissions.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to the calculation and reporting of emissions from controlled atmospheric storage tanks.

Comment: One commenter requested that the EPA remove the term ''maximum potential'' from 40 CFR 98.233(j)(4)(i)(A), as assuming worst-case conditions would be required to determine a maximum potential case, which does not reflect actual operations. The commenter states that this does not further the EPA's goal of accurately determining emissions.

Response: The EPA did not intend for reporters to calculate emissions using worst-case conditions for this step of the calculation methodology for controlled atmospheric storage tank emissions. Rather, the EPA had intended the language to signify that reporters should calculate their vented emissions from the atmospheric storage tank without reducing emissions for controls. However, we agree with the commenter that this language could be misunderstood. In the final rule, the EPA is revising 40 CFR 98.233(j)(4)(i)(A) from proposal by removing the proposal term ''maximum potential'' and adding language to clarify that emissions in this step of the methodology should represent the emissions from the atmospheric storage tank prior to the vapor recovery system or flare, consistent with the original intent of the provision.

5. Calculation Methods 1 and 2 for Atmospheric Storage Tanks

a. Summary of Final Amendments

The EPA is finalizing that reporters would collect measurements of the simulation input parameters listed under 40 CFR 98.233(j)(1)(i) through (vii), consistent with section II.B. of this preamble, with the following changes from proposal. After consideration of comments received, in an effort to reduce burden on reporters, we are specifying that, with the exception of the API gravity, composition and Reid vapor pressure required by 40 CFR 98.233(j)(1)(iii) and (vii), the measurements must be taken at least annually since the maximum time period covered by a simulation would be the reporting year, as we expect these measurements to be more easily attainable or significantly variable between reporting years. For API gravity, composition, and Reid vapor pressure, and per 40 CFR 98.233(j)(1)(iii) and (vii), measurements would be required to be conducted within six months of start-up or by January 1, 2030 (*i.e.,* within five years of the effective date of the rule), whichever is later, and at least once every five years thereafter. Relatedly, we are combining the API gravity model input at 40 CFR 98.233(j)(1)(iii) with the composition and Reid vapor pressure model inputs at 40 CFR 98.233(j)(1)(vii) so that all model input parameters with the sampling frequency different from annual are contained in the same subparagraph. Until such time that a sample can be collected, reporters may continue to determine API gravity by engineering estimate and process knowledge based on best available data and composition and Reid vapor pressure by using one of the existing methods described in 40 CFR 98.233(j)(1)(vii)(A) through (C). We are finalizing similar edits in 40 CFR 98.233(j)(2)(i). We are also finalizing the removal of the provisions of 40 CFR 98.233(j)(2)(ii) and (iii) as proposed, which allowed for representative compositions to be used for tanks receiving liquids directly from wells or non-separator equipment. For the measured parameters in 40 CFR 98.233(j)(1)(i) through (vii), we are clarifying in the final rule that measurements must only be taken if the parameter is an input to the modeling software selected by the reporter.

We are finalizing the addition of ProMax as an example software program for calculating atmospheric tank emissions per 40 CFR 98.233(j)(1) as proposed, consistent with section II.B. of this preamble. Consistent with the EPA's revisions to 40 CFR 98.233(e)(1) for dehydrators, the EPA is requiring the use of ProMax version 5.0 or above.

The EPA is finalizing the amendments to 40 CFR 98.233(j) as proposed such that facilities with wells flowing directly to atmospheric storage tanks without passing through a separator may use either Calculation Method 1, Calculation Method 2, or, for wells, gas-liquid separators, or non-separator equipment with annual average daily throughput greater than 0 barrels per day and less than 10 barrels per day, Calculation Method 3, consistent with section II.B. of this preamble. We are also finalizing the conforming edits within 40 CFR 98.233(j)(1) and (2) and 40 CFR 98.236(j)(1) to refer to parameters and requirements for wells flowing directly to atmospheric storage tanks.

We are finalizing the reorganization of the reporting requirements in 40 CFR 98.236(j)(1) as proposed, consistent with section II.C. of this preamble. In the final rule, tank counts are collected under 40 CFR 98.236(j)(1)(x)(A) through (F), and the reporting of CO_2 and CH_4 vented emissions and recovered mass is reported under 40 CFR 98.236(j)(1)(xi) through (xiv). The EPA is also finalizing the removal of 40 CFR 98.236(j)(1)(xi) as proposed. The EPA is finalizing 40 CFR 98.236(j)(1)(vii) and (viii) with revisions from proposal to require the flow-weighted average concentration (mole fraction) of CO_2 and CH_4 in the flash gas, rather than the minimum and maximum values, for only those reporters that used Calculation Method 1 to determine emissions from atmospheric storage tanks.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to calculation methodologies 1 and 2 for atmospheric storage tanks.

Comment: Several commenters requested clarification on whether the EPA intends for input parameters to model tank emissions calculated using Calculation Method 1 to be measured annually. Commenters requested a five-year measurement time frame in which measurements are gathered every five years due to the high level of burden that the measurement and sampling requirements impose.

Response: The proposed requirements to measure certain inputs for Calculation Methods 1 and 2 were not prescriptive with regard to a time frame to obtain measurements. The EPA only specified in 40 CFR 98.233(j) that if an applicable parameter must be measured, the reporter must ''collect measurements reflective of representative operating conditions over the time period covered by the simulation.''

Regarding the frequency of measurement, as explained in the preamble to the 2023 Subpart W Proposal, we proposed that reporters would collect measurements reflective of representative operating conditions over the time period covered by the simulation. In addition, we proposed that the parameters that must be used to characterize emissions should reflect operating conditions over the time period covered by the simulation rather than just over the calendar year. Under this proposed change, reporters could continue to run the simulation once per year with parameters that are determined to be representative of operating conditions over the entire year. Alternatively, reporters would be allowed to conduct periodic simulation runs to cover portions of the calendar year, as long as the entire calendar year is covered. The reporter would then sum the results at the end of the year to determine annual emissions. In that case, the parameters for each simulation run would be determined for the operating conditions over each corresponding portion of the calendar year.

Requirements for measurement frequency for 40 CFR 98.233(j)(1)(i) through (vi) are being clarified in the final provisions to specify that for these input parameters, the measurements must be taken at least once per year where parameters are determined to be representative of operating conditions over the entire year, or the measurements must be taken multiple times per year, where the measurements are reflective of representative operating conditions over shorter time periods. However, after consideration of the significant burden noted by commenters to sample all hydrocarbon liquid and produced water storage tanks within their facility each reporting year, the EPA is finalizing a reduced frequency schedule in 40 CFR 98.233(j)(1)(vii) for API gravity, composition and Reid vapor pressure sampling and analysis from each well, separator, or non-separator equipment. Reporters must sample and analyze sales oil or stabilized hydrocarbon liquids for API gravity, hydrocarbon liquids or produced water composition, and hydrocarbon liquids Reid vapor pressure within six months of equipment star-up, or by January 1, 2030, whichever is later, and at least once every five years thereafter. Until such time that a sample can be collected from the well, separator, or non-separator equipment, reporters may determine API gravity by engineering estimate and process knowledge based on best available data, and composition and Reid vapor pressure using one of the representative methods in 40 CFR 98.233(j)(1)(vii)(A) through (C). We believe that measurements taken at this frequency will be sufficiently representative of the API gravity, composition and Reid vapor pressure as we do not expect significant changes in comparison to cases where physical or operational changes, such as when a well feeding the atmospheric pressure storage tank undergoes fracturing or refracturing, are made.

Comment: One commenter stated that not all process simulation software requires all of the input parameters listed in 40 CFR 98.233(j)(1) to run the model. The commenter noted that in some process simulators (*e.g.,* BR&E ProMax, AspenTech HYSYS), if a hydrocarbon liquids composition is provided for the tank feed, API gravity and Reid Vapor Pressure are not needed as inputs to the simulation as these can be calculated from the other input parameters.

Response: The EPA understands that the different modeling software options available to reporters may require different input parameters in order to produce an accurate emissions estimate for atmospheric tanks. We agree with the commenter that only the input parameters that are required to run the model need to be measured. Therefore, in the final rule, the EPA is clarifying the language in 40 CFR 98.233(j)(1)(i) through (vii) to reflect this.

Comment: One commenter noted that additional edits are required to 40 CFR 98.236(j)(1)(vii) and (viii), as these requirements to report flash gas CO_2 and CH_4 concentrations seem to be specific to Calculation Method 1. The commenter stated that for Calculation Method 2, reporters must assume the CO_2 and CH_4 in solution from the oil sent to tanks is emitted to atmosphere, so the concentrations of CO_2 and CH_4 in the flash gas are not known.

Response: The EPA agrees with the commenter that, for reporters using the emissions calculation methodology described in 40 CFR 98.233(j)(2), facilities must assume all CO_2 and CH_4 in solution from hydrocarbon liquids sent to tanks would be emitted to atmosphere. Therefore, the EPA agrees that these flash gas concentrations for these GHGs are not known when using Calculation Method 2 and so has revised 40 CFR 98.236(j)(1)(vii) and (viii) to be only applicable when Calculation Method 1 is used.

6. Calculation Method 3 for Atmospheric Storage Tanks

The EPA is finalizing amendments for Calculation Method 3 atmospheric storage tanks as proposed, consistent with section II.C. of this preamble. The EPA received only minor comments regarding the revisions to Calculation Method 3 for atmospheric storage tanks. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

The EPA is finalizing amendments to 40 CFR 98.233(j)(3) as proposed to clarify that the separators, wells, or non-separator equipment for which emissions are calculated should be those with annual average daily hydrocarbon liquids throughput greater than 0 barrels per day and less than 10 barrels per day (*i.e.,* the count variable in equation W–15A should not include separators, wells, or non-separator equipment that had no throughput during the year). Similarly, we are also finalizing amendments as proposed to clarify that the count of separators, wells, or non-separator equipment to report under 40 CFR 98.236(j)(2)(ii)(E) should also be those with annual average daily hydrocarbon liquids throughput greater than 0 barrels per day and less than 10 barrels per day.

The EPA is also finalizing as proposed amendments to require reporting of all Calculation Method 3 emissions that are vented directly to atmosphere under 40 CFR 98.236(j)(2)(ii). These revisions amend subpart W to no longer require separate reporting of Calculation Method 3 emissions from atmospheric storage tanks that did not control emissions with flares and those that controlled emissions with flares.

The EPA is finalizing as proposed amendments to 40 CFR 98.236(j)(2)(ii)(E) to request the total number of separators, wells, or non-separator equipment used to calculate Calculation Method 3 storage tank emissions. This revision will completely align the reporting requirement with the total ''Count'' input variable in equation W–15A. We are also finalizing requirements to collect this information at the well-pad site, gathering and boosting site, or facility level. The EPA is also finalizing as proposed the removal of the reporting requirement previously in 40 CFR 98.236(j)(2)(i)(F) that required reporting of the number of wells without gas-liquid separators in the basin.

L. Flared Transmission Storage Tank Vent Emissions

The EPA is finalizing the removal of source-specific calculation and reporting of flared emissions from transmission storage tanks (renamed ''condensate storage tanks'' as described in section III.C.1. of this preamble). The EPA received only minor comments regarding the revisions for condensate storage tanks. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

As discussed in the proposal preamble, the EPA determined that including flared emissions from condensate storage tank vents in the group of ''other flared sources'' instead of continuing to report source-specific flared emissions from transmission tanks will not affect data quality or accuracy, nor will it significantly impact the EPA's knowledge of the industry sector, emissions or trends. Therefore, consistent with section II.C. of this preamble, the EPA is finalizing as proposed the removal of both the current requirements in 40 CFR 98.233(k)(5) that require reporters to calculate flared tank vent stack emissions from this source separately from all other flared emissions at the facility and the current associated reporting requirements at 40 CFR 98.236(k)(3). Instead, the final amendments, as proposed, require data for streams from condensate storage tanks to be included in the calculation of total emissions from a flare according to 40 CFR 98.233(n)(1) through (9), and the flared condensate storage tank emissions are classified with all ''other'' flared sources under the flare disaggregation requirements at 40 CFR 98.233(n)(10). Similarly, the EPA is finalizing as proposed the reporting of flared condensate storage tank emissions as part of the total emissions from the flare in 40 CFR 98.236(n)(16) through (18) and as part of the disaggregated ''other flared sources'' emissions in 40 CFR 98.236(n)(19).

M. Associated Gas Venting and Flaring

1. Summary of Final Amendments

The EPA is finalizing changes to associated gas venting and flaring largely as proposed. More specifically, we are finalizing changes to 40 CFR 98.233(m)(3) that require a reporter measuring the flow of natural gas to a vent using a continuous flow measurement device to use the measured flow volumes to calculate the volume of gas vented, consistent with section II.B. of this preamble. If the reporter does not use a continuous flow measurement device, the reporter must calculate emissions from associated gas using equation W–18. As proposed, we are finalizing clarifying language for the data input, volume of gas sent to sales (SGp), when using equation W–18. The volume of gas sent to sales includes gas used for other purposes at the facility site, including powering engines, separators, safety systems and/or combustion equipment and not flared or vented. The final rule, as proposed, also clarifies that reporters using equation W–18 use the volume of gas sent to sales and the volume of oil produced as inputs into equation W–18 only during periods when associated gas is vented or flared. These changes will improve the accuracy of data collected for venting and flaring associated gas. The final rule also includes changes from proposal to 40 CFR 98.233(m) to clarify, consistent with the intent of the proposed rule, that the use of measured gas flow (in lieu of equation W–18) is not optional if reporters use a continuous flow measurement device. We are finalizing the corresponding reporting requirements in 40 CFR 98.236(m)(7) to include, as proposed, a requirement to indicate whether a continuous flow monitor was used to measure flow rates and a continuous composition analyzer was used to measure CH_4 and CO_2 concentrations. For vented wells, we are also finalizing as proposed the requirement to report the flow-weighted mole fractions of CH_4 and CO_2 and the total volume of associated gas vented from the well, in standard cubic feet for all wells whether using GOR or continuous flow measurement devices.

Consistent with treatment of flaring emissions in other sources and as proposed, the EPA is finalizing calculation of flared associated gas emissions under 40 CFR 98.233(n), Flare Stacks, with some data elements for flaring associated gas continuing to be reported under 40 CFR 98.236(m) and others under 40 CFR 98.236(n). However, as further discussed in section III.N. of this preamble, under certain circumstances, the final rule provisions allow reporters to use equation W–18 to determine inputs to the 40 CFR 98.233(n) flared associated gas emission calculations. More specifically, reporters determine gas flow volumes routed to flares using continuous parameter monitoring systems as specified in 40 CFR 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and determine gas composition using continuous gas composition analyzers or gas sampling as specified in 40 CFR 98.233(n)(4). If the reporter does not use continuous flow measurements, the reporter must calculate natural gas emissions for associated gas routed to the flare using the calculation methods in 40 CFR 98.233(m) as specified in 40 CFR 98.233(n)(3)(ii)(B).

We are also finalizing several reporting requirements from the proposal in 40 CFR 98.236(m). The volume of oil produced and the volume of gas sent to sales reported in 40 CFR 98.236(m)(5) and (6), respectively, when using equation W–18 are limited to the volumes produced and sent to sales during periods when associated gas is vented or flared. Further, as proposed, 40 CFR 98.236(m)(6) is finalized to clarify that the volume of gas sent to sales includes volumes of gas used on-site during periods when associated gas is vented or flared. Finally, we are finalizing the rule as proposed to specify that reporters do not report equation W–18 inputs if they calculate volumetric emissions from associated gas venting and flaring using a continuous flow measurement device rather than using equation W–18. These equation W–18 data elements include the GOR, the volume of oil produced, and the volume of gas sent to sales for wells with associated gas venting or flaring.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to associated gas venting and flaring.

Comment: Commenters strongly supported the EPA's proposal to require operators to measure the volume of associated gas sent to flares using flare stack methodologies instead of a GOR contending that use of GOR is problematic, because gas production varies by large factors over time scales from minutes to years.

Response: The EPA acknowledges that GOR can and does change, especially over longer time horizons. This is expected as oil and gas production leads to changing reservoir properties resulting in changes to production quantities and GORs. At production sites, GOR is often determined through a well test where produced oil and gas are routed to a test separator for a specified period of time. Oil and gas volumes are metered off the separator to determine a value for GOR.

In finalizing today's rule, the EPA believes that direct measurement provides values for gas flow and composition with the highest degree of confidence. We are, therefore, finalizing the calculation methods in 40 CFR 98.233(m) to require that reporters use measured data in calculating and reporting emissions from associated gas venting and flaring if gas flow rates are metered in addition to the existing requirements, which are not changing with this action, that gas composition be determined through use of continuous gas composition analyzers if these are available. Although we proposed that equation W–18 would only be allowed for calculating vented emissions, we recognize based on public comment that measurement may not always be possible due to operational practices, site health and safety protocols, equipment failure, or for other reasons. As such, we are finalizing the rule today allowing use of equation W–18 in instances where direct measurement data are not available for either venting or flaring of associated gas. It is essential that reporters have access to an alternative methodology that supports accurate calculation of emissions from associated gas venting and flaring. The final rule also addresses two factors that may have impacted the accuracy and verification of reported emissions in previous years when using equation W–18. The EPA, as discussed elsewhere in this section, is finalizing the rule to require reporting of associated gas emissions and other data elements at the well level. Under the existing rule, facilities are required to report one average GOR value across all associated gas wells in the sub-basin. Although equation W–18 currently requires the use of a well-specific GOR for each well when calculating emissions, it is possible that some reporters may have used the average GOR value when calculating emissions for each well rather than the well-specific GOR. Well-level reporting with well-specific GOR will allow the EPA to verify that associated gas emission calculations are being performed correctly using well-specific GOR values, and we are finalizing this requirement in this action. The final rule also specifies that, as proposed, the volume of oil produced and the volume of gas sent to sales are only calculated during the period when associated gas is vented or flared.

Comment: The EPA received comments supporting use of continuous flow measurement as an alternative to equation W–18 to calculate emission from associated gas and venting, stating that flexibility is key for many owners and operators and reflects the diversity in resources available to an owner or operator and the location and nature of its assets. One commenter noted that it may be challenging to accurately measure extremely low volumes or variable volumes of gas.

Response: The EPA acknowledges the commenter's support for the proposed calculation methods for associated gas venting but is clarifying the intent. As stated in section III.M. of the preamble to the 2023 Subpart W Proposal and specified in the proposed regulatory text, was to require reporters to use the measured data if they used a continuous measurement device. Specifically, the preamble to the proposed rule stated, ''For associated gas venting emissions, we are proposing provisions in 40 CFR 98.233(m)(3) to specify that if the reporter measures the flow to a vent using a continuous flow measurement device the reporter must use the measured flow volumes to calculate the volume of gas vented rather than using equation W–18.'' (88 FR 50332; August 1, 2023). Further, the EPA proposed the following regulatory text in 40 CFR 98.233(m)(3) establishing this requirement, ''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.'' (88 FR 50397; August 1, 2023). Therefore, the proposal intended equation W–18 to only be available to calculate vented associated gas emissions if the reporter does not use a continuous measurement device. Although we believe the intent was clear, given the ''if you . . . you must . . .'' language, we are further clarifying the provision in the final rule such that it does not use the term ''alternatively'' and additionally changing the order of the wording to first state that a reporter using a continuous flow measurement device must use the measured flow volumes to calculate emissions, and then state if the reporter does not use a measured flow measurement device, then equation W–18 must be used.

Regarding the comments requesting flexibility with emphasis on measurement of low flows and variability of flow, the EPA acknowledges that gas flow rates during production can be variable. We disagree, though, that it will be challenging to measure gas flow at low flow rates. Flow meters used at production sites are capable of measuring very low flow rates, even to less than 1,000 cubic feet per day depending on pipe diameter. We agree, however, that variability in flow can present a challenge to operators when measuring gas flow rates using orifice meters. Flow rates that exceed the flow capacity of an orifice cross section will necessitate change out of the orifice plate. This can be challenging in cases with highly variable flow over short periods of time due to the labor, time and equipment required to replace the orifice plate at high frequency. Reporters anticipating or experiencing high variability in flow may consider using flow meters that are designed to manage the variability. If this is not possible or reporters do not elect to do so, reporters may use equation W–18 to calculate emissions from associated gas venting and flaring.

Comment: Most commenters supported not requiring the submission of equation W–18 inputs if the equation is not used to calculate emissions from venting associated gas. However, one commenter suggested that it should be clearer that if equation W–18 is used, then reporters must report those data elements.

Response: The EPA acknowledges the support for the proposed rule. While the EPA agrees that under the final rule reporters do not report equation W–18 inputs if they calculate volumetric emissions from associated gas venting and flaring using a continuous flow measurement device rather than using equation W–18, the EPA disagrees that further clarification of the rule language is needed. The EPA is finalizing 40 CFR 98.236(m)(4) through (6) as proposed, which requires that each data element be reported unless the reporter did not use equation W–18 to calculate associated gas venting or flaring emissions.

Comment: A reporter sought clarification if the EPA is asking for reporters to measure the amount of gas vented when bleeding pressure off a well, stating that this would not be practical as it would require many operational units to add flow measurement devices for many day-to-day operations that scarcely ever vent, possibly only a couple times a year. The commenter further noted that this would require every pulling unit in the basin to add a flow meter, and composition analyzer. They would be required to record and track this data daily and report to the operator.

Response: The primary purpose in bleeding pressure off a well is to allow for safe work on the well. Natural gas that is bled off an oil well is considered associated gas because the natural gas being vented is associated with oil production. Although the EPA recognizes these are often short duration events, often just a few minutes, a bleed off produces GHG emission at a well site if the gas is vented or flared. Multiple well bleeding events at a well site could result in sizeable emissions depending on the duration of the events. Generally, vented emissions from well bleed offs at oil wells should be included in reported associated gas emissions for the well. However, there may be instances where emissions from bleeding a well are reported under a different source, most likely completions and workovers without hydraulic fracturing. For example, the commenter references pulling units. Pulling units are often used at production pads to perform well workovers. If so, emissions associated with bleeding the well are considered to be from the workover. Emissions for this event would be calculated and reported under the Completions and Workovers without Hydraulic Fracturing source using the calculation methods in 40 CFR 98.233(h) and 98.236(h). Regardless, the EPA emphasizes that the final rule does not require reporters venting associated gas to place a flow meter on a vent line from the well as suggested by the commenter. As proposed, the EPA is finalizing the calculation methods for associated gas venting and flaring to require use of measured data when reporters measure the gas flow rate. If flow rates are not measured, reporters can use equation W–18 to calculate emissions from associated gas venting, including well bleeding events.

N. 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.[52]

The EPA is finalizing changes to the flared emissions calculation methodologies and the flare data reporting requirements for both the flared emissions from each source type and for each flare with modifications from the proposed amendments, as discussed in the following sections. The final changes will align the flared emissions calculation methodology and reporting with the directives in CAA section 136(h) that reported emissions be based on empirical data and accurately reflect the total CH_4 emissions from each facility, consistent with section II.B. of this preamble. We are also finalizing changes to clarify specific provisions.

1. Calculation Methodology for Total Emissions From a Flare

a. Summary of Final Amendments

The EPA is finalizing several revisions to the flare emission calculation methods to improve the quality and accuracy of the calculated and reported data. Additionally, after consideration of public comments, the final requirements include several revisions from the proposal as well as some minor clarifications and other enhancements.

First, we are finalizing several revisions to requirements for determining both the destruction efficiency and the combustion efficiency to use in calculating emissions from flares. The current rule and the proposal both specify only combustion efficiencies. However, after consideration of comments and consistent with section II.B. of this preamble, we are finalizing requirements to use destruction efficiencies for calculating CH_4 emissions and to use combustion efficiencies for calculating CO_2 emissions. Consistent with previous EPA determinations[53] and regulations such as the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (40 CFR part 63, subpart CC) (hereafter referred to as ''NESHAP CC''), the final amendments specify that combustion efficiency is 1.5 percent lower than the destruction efficiency (*e.g.,* if the destruction efficiency is 95 percent, then the corresponding combustion efficiency is 93.5 percent). Consistent with CAA section 136(h), we are finalizing as proposed a tiered approach to setting a range of default efficiencies that provide higher defaults when supported by data from the reporter implementing certain flare monitoring procedures, in 40 CFR 98.233(n)(1). As noted by commenters, the default efficiency values in the proposal were incorrectly identified as combustion efficiencies; the final rule retains the default values and correctly identifies them as destruction efficiencies. In addition, the final amendments add corresponding default combustion efficiencies that are 1.5 percent lower than the default destruction efficiencies, which will result in more accurate estimates of CO_2 emissions. Specifically, the final default destruction efficiency and combustion efficiency are 98 percent and 96.5 percent, respectively, for Tier 1, 95 percent and 93.5 percent, respectively, for Tier 2, and 92 percent and 90.5 percent, respectively, for Tier 3. We are finalizing as proposed that the default Tier 1 efficiencies are appropriate and allowed where the reporter follows specified procedures in NESHAP CC to ensure such efficiencies are accurate.

Note that the definitions of flare in subpart W and in NESHAP CC are not the same. In subpart W, a flare is defined as ''a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.'' In NESHAP CC, the flare definition does not include combustion devices with an enclosed combustion chamber (*i.e.,* a closed flame). Thus, the requirements in NESHAP CC are different for ''enclosed combustion devices'' and for ''open'' flares. The final subpart W Tier 1 requirements recognize this difference in the NESHAP CC combustion device requirements. Specifically, for enclosed combustion devices that are utilizing the Tier 1 efficiencies, subpart W requires that the applicable testing procedures specified in 40 CFR 63.645 are followed, as well as the applicable monitoring procedures in 40 CFR 63.644. For combustion devices that use an open flame, the applicable requirements specified in 40 CFR 63.670 and 40 CFR 63.671 of NESHAP CC must be followed. In addition, for either enclosed combustors or open flares, subpart W Tier 1 requires that the applicable records in 40 CFR 63.655 are maintained to demonstrate that the NESHAP CC testing and monitoring requirements are being followed. While subpart W cross-references the NESHAP CC requirements, sources utilizing Tier 1 are not affected sources that are subject to NESHAP CC.

The proposed rule did not specify how to address situations where an owner or operator is utilizing the Tier 1 default efficiency but fails to meet the testing and monitoring requirements (cross-referencing certain requirements in NESHAP CC). Examples of ''failing to meet the testing and monitoring requirements'' would include, but not be limited to, instances where monitoring data was not collected for 75 percent of the operating hours in a day, instances where the monitoring parameters were outside of the established parameter ranges, and instances where the required visible emissions testing was not performed. Similarly, during periods when the applicable 40 CFR 63.644, 63.645,

[52] Flare stacks are an emission source type currently 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.

[53] See *Parameters for Properly Designed and Operated Flares*, USEPA Office of Air Quality Planning and Standards. April 2012. Available at *https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

63.670 and 63.671 requirements are not being met, it generally would not be appropriate to continue to assume 98 percent destruction efficiency (and 96.5 percent combustion efficiency). The EPA considered requiring that the Tier 3 default efficiencies be applied any time these requirements are not being met. However, the EPA recognizes that there could be short-term episodes where one or more of the required parameters are not being met, and such an immediate requirement would require frequent oscillations between applying the Tier 1 and Tier 3 default efficiencies. The EPA concluded that this would be difficult to implement and would likely be burdensome for owners and operators. The EPA evaluated durations that would be appropriate to require switching to the Tier 3 default to ensure accuracy of total emissions reported. While NESHAP CC specifies a 45-day timeframe for allowing owners and operators to correct various types of problems, for subpart W regulations the purpose of the requirements is ensuring accurate total emissions reporting through the appropriate use of the different tiers of default destruction/combustion efficiencies. Therefore, for the final rule, the EPA selected a 15-day time frame such that, if one or more of the specific NESHAP CC testing and monitoring requirements that apply in the Tier 1 requirements are not met for 15 consecutive days, the owner or operator must apply the Tier 3 default efficiency from the time the requirement was initially not met (*i.e.,* at the beginning of the 15 days) until such time that all requirements are being met once again. At that time, the Tier 1 default efficiencies could be applied going forward. The concept of applying different flare efficiencies based on operating conditions is similar to adjusting the flare emissions to account for periods when the flare is unlit and thus, appropriately accounting for times when the flare is not achieving any emission reduction (*i.e.,* zero combustion efficiency). We expect that the 15-day grace period will have a minimal impact on overall reported emissions because we expect most periods when a reporter fails to meet the testing and monitoring requirements will be short. The 15-day grace period is intended to capture significant periods when the testing and monitoring requirements are not met (*i.e.,* a 15-day grace period for a continuously operated flare would be 4.1 percent of the total operating hours).

Similarly, we are finalizing as proposed that the default Tier 2 efficiencies are appropriate and allowed if the reporter follows the requirements that ensure such efficiencies are accurate, and that such requirements under subpart W are consistent with the procedures specified in NSPS OOOOb corresponding to a 95 percent destruction efficiency (as cross-referenced in the subpart W final regulations). As discussed above, the final rule also includes the default combustion efficiency of 93.5 percent. Owners and operators of sources that are subject to NSPS OOOOb can utilize the Tier 2 efficiencies by complying with the requirements. In addition, owners and operators that are not subject to NSPS OOOOb can elect to follow the cross-referenced requirements. Note that, as discussed above for NESHAP CC, voluntarily following the NSPS OOOOb requirements in order to claim the subpart W Tier 2 default efficiencies will not make the sources affected facilities under NSPS OOOOb. While the proposed Tier 2 requirements cross-referenced only the specific section in proposed NSPS OOOOb that contained the monitoring requirements contained in 40 CFR 60.5417b, the final rule includes additional requirements from those proposed, through a more comprehensive cross-reference incorporation of relevant requirements in NSPS OOOOb. As with NESHAP CC, the definition of flare in NSPS OOOOb does not include enclosed combustors and there are separate requirements for enclosed combustors and open flares. NSPS OOOOb requires that enclosed combustors be tested to demonstrate 95 percent destruction efficiency, but includes the option for owners and operators to use combustors initially tested by the manufacturer (rather than to perform the initial test on-site). The final subpart W recognizes the different NSPS OOOOb requirements for these three types of combustion devices and includes cross-references accordingly. Specifically, for enclosed combustion devices tested on-site, the requirements in 40 CFR 60.5412b(a)(1) are cross-referenced, along with testing requirements in 40 CFR 60.5413b, and the continuous compliance and continuous monitoring requirements in 40 CFR 60.5415b(f) and 60.5417b, respectively. For enclosed combustion devices tested by the manufacturer in accordance with 40 CFR 60.5413b(d), the final subpart W Tier 2 requires that the NSPS OOOOb requirements in 40 CFR 60.5413b(b)(5)(iii) and (e) and the applicable continuous compliance and continuous monitoring requirements in 40 CFR 60.5415b(f) and 40 CFR 60.5417b, respectively, are met. Finally, for open flares, the final rule requires that the NSPS OOOOb requirements in 40 CFR 60.5412b(a)(3) be followed, along with the applicable continuous compliance and continuous monitoring requirements in 40 CFR 60.5415b(f) and 40 CFR 60.5417b, respectively. For all three types, the final rule requires that the applicable records required by 40 CFR 60.5420b(c)(11) be maintained to demonstrate that the testing, monitoring procedures are being followed.

The EPA recognizes that many oil and gas sources that are not subject to NSPS OOOOb will be subject to an approved state plan or applicable Federal plan in 40 CFR part 62 that includes similar requirements to NSPS OOOOb to ensure that flare/combustion device destruction efficiency of 95 percent is met. For such sources, compliance with such an approved state plan or applicable Federal plan in 40 CFR part 62 allows the use of the Tier 2 efficiencies, provided that the requirement is a 95 percent reduction in methane emissions.

As with Tier 1, if owners and operators fail to meet one or more of the Tier 2 requirements for 15 consecutive days, the Tier 3 default efficiencies must be used until such time that all requirements are again met. Examples of failing to meet the Tier 2 requirements include, but are not limited to, when the average value of a monitoring parameter is above the maximum, or below the minimum, operating parameter, when monitoring data are not available for at least 75 percent of the hours in an operating day, when the visible emission testing results in visible emissions in excess of 1 minute in any 15 minute period.

Note that sources that are subject to either NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62 are allowed to voluntarily "step up" to Tier 1 and thus use the 98 percent destruction efficiency and 96.5 percent combustion efficiency default values.

We are also finalizing as proposed that Tier 3 applies if neither Tier 1 nor Tier 2 requirements are met. Additionally, the final Tier 3, as proposed, would apply before the flare owner or operator has implemented the relevant monitoring that would be required to comply with NESHAP CC, NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62.

After consideration of public comments and consistent with section II.B. of this preamble, we are also finalizing several additional changes from the proposed flare efficiency requirements. One of the new final provisions is an option that allows reporters to use destruction and combustion efficiencies different than the default values when they elect to use an alternative test method that has been approved under 40 CFR 60.5412b(d) of NSPS OOOOb. The alternative test method must directly measure combustion efficiency, and the procedures in 40 CFR 60.5415b(f)(1)(x) and (xi) and 40 CFR 60.5417b(i) must be met, as well as all conditions in the monitoring plan prepared in accordance with 40 CFR 60.5417b(i)(2).

The final amendments also include a new option that applies to enclosed combustion devices (a subset of flares in subpart W). Specifically, as an alternative to conducting a performance test following the procedures in NSPS OOOOb, the final amendments to this subpart allow a reporter to conduct a performance test using EPA Other Test Method 52 (OTM–52, *Method for Determination of Combustion Efficiency from Enclosed Combustors Located at Oil and Gas Production Facilities,* dated September 26, 2023, for enclosed combustion devices that are not required to comply with NSPS OOOOb or an approved state plan or applicable Federal plan in 40 CFR part 62. This method determines combustion efficiency, whereas the test method specified in NSPS OOOOb determines destruction efficiency. Thus, the final amendments specify that when an OTM–52 test results in a combustion efficiency greater than 93.5 percent, then the reporter may use the default destruction and combustion efficiencies of Tier 2.

Second, for all flares, regardless of the tier discussed previously in this section, we are finalizing requirements, mostly as proposed, to determine the presence of a pilot flame or combustion flame. The final amendments, like the proposed amendments, require either continuous monitoring (40 CFR 98.233(n)(2)(i)) or visual inspection at least once per month (40 CFR 98.233(n)(2)(ii)) for the presence of pilot flame or combustion flame. However, the final amendments include a statement specifying that the visual inspection option is allowed only when the facility complies with the Tier 3 efficiency or an approved alternative test method that does not include continuous monitoring for the presence of a flame. This statement does not change the intent of the pilot monitoring requirements since proposal. We added this statement to clarify that facilities subject to or electing to comply with the Tier 1 or Tier 2 efficiencies must comply with the continuous monitoring for the presence of a pilot flame or combustion flame as specified in the cross-referenced NESHAP CC or NSPS OOOOb, respectively, as proposed. After consideration of public comment, the following new requirements are also included in the final amendments. The final amendments include an option to use either video surveillance or advanced remote monitoring methods as examples of acceptable continuous monitoring devices that may be used. The final amendments also explicitly allow multiple or redundant monitoring devices and require either a visual inspection of the flame or a check of output from a video surveillance system whenever there is a discrepancy between the monitoring devices to assess which monitoring device is providing inaccurate readings. We are finalizing as proposed the requirement that continuous monitoring devices must monitor for the presence of a pilot flame or combustion flame at least once every 5 minutes. We are also including an additional provision in the final amendments (40 CFR 98.233(n)(2)(iii)) to clarify that any screening conducted using an alternative technology under NSPS OOOOb that detects an unlit flare and is confirmed by a ground survey constitutes a pilot flame inspection under subpart W, and the results of such surveys, together with all other monitoring and inspections that determine the flare is unlit, must be used to calculate both the time the flare was unlit during the year and the fraction of total gas routed to the flare during periods when it was unlit.

Third, we proposed a requirement to use a continuous parameter monitoring system to determine either total flow volume at the inlet to the flare or the volumes for each stream from individual sources that is routed to the flare. Use of a continuous parameter monitoring system would require flow determination based on direct measurement using a flow meter if one is present or indirect calculation of flow using other parameter monitoring systems combined with engineering calculations, such as line pressure, line size, and burner nozzle dimensions. After consideration of public comments, we are not finalizing this proposed requirement and are instead finalizing requirements that are comparable to requirements for determining flow in the current rule. Currently, under 40 CFR 98.233(n)(1), if a continuous flow measurement device is used on part or all of the gas routed to the flare, then the measurement data must be used in the calculation of emissions from the flare. For the portion of gas not measured by a continuous flow measurement device, the reporter currently may estimate the flow using engineering calculations based on process knowledge, company records, and best available data. To calculate flared emissions from individual source types, the current rule specifies that flow from the source to the flare be determined using simulations (for dehydrators and storage tanks) or any of the engineering calculation options that are used to calculate flow of vented emissions. Our intent is that methods in the final amendments for determining flow align with the current requirements, except for the four following additional options and clarifications. First, 40 CFR 98.233(n)(3)(i) in the final amendments provides a new option for indirectly calculating total flow into the flare based on parameter monitoring systems combined with engineering calculations, such as line pressure, line size, and burner nozzle dimensions. This option is specified in NSPS OOOOb for determining flow into a flare; we have added it to the subpart W final amendments so that a reporter that uses this method to comply with NSPS OOOOb can calculate emissions under subpart W using the same data. Second, for clarity, all of the requirements for determining flow of streams from individual sources are either consolidated in, or cross-referenced from, 40 CFR 98.233(n)(3)(ii) rather than being dispersed throughout other sections of the rule. Third, new options are provided in 40 CFR 98.233(n)(3)(ii)(B)(1) to use either process simulation or engineering calculations that are specified in 40 CFR 98.233(d) for calculating flow of vented gas streams from acid gas removal units. These options were added so that a facility may use the same procedures for determining flow of streams routed to flares that are also specified for determining flow of vented streams from the same source types. Fourth, since some of the source-specific engineering calculation methods for calculating vented emissions calculate only the volume of GHG constituents in the gas stream, 40 CFR 98.233(n)(3)(ii)(B)(8) requires reporters to calculate the flow of non-GHG constituents in those streams using engineering calculations based on best available data and company records. This was not necessary in the proposed revisions since they required measurement of the total flare gas, which would include both GHG and non-GHG constituents. Finally, while reviewing a comment that recommended adding recordkeeping requirements, we realized that the proposed rule did not clearly convey our intent that the term ''flow of gas from each source that routes gas to the flare'' in proposed 40 CFR 98.233(n)(1)(ii) should include only the flow that actually enters the flare. In the final rule, 40 CFR 98.233(n)(3)(ii) specifies that closed vent system leaks and bypass volumes that are diverted from the flare should be excluded from the calculated and reported volume of gas routed to the flare and that that the closed vent system leaks and bypass volumes that are diverted directly to atmosphere must be used in the calculation and reporting of vented emissions from the applicable sources. See the comment and response on recordkeeping requirements in section III.N.1.b. of this preamble for a discussion of the applicable recordkeeping requirements under the final rule and a discussion of the requirements for closed vent system leaks and bypass volumes.

Fourth, we proposed a requirement that composition of either the total gas stream at the inlet to the flare or for each of the streams from individual sources that are routed to the flare be calculated using either a continuous gas composition analyzer or by collecting samples for compositional analysis at least once each quarter in which the flare operated. After consideration of public comments, we are not finalizing this proposed requirement and are instead finalizing requirements that are comparable to requirements for calculating composition in the current rule. For example, the final rule specifies that if a reporter is using a continuous gas composition analyzer on gas to the flare, then the measured data must be used in the calculation of emissions from the flare, which is consistent with 40 CFR 98.233(n)(2) of the current rule. The final rule specifies that if a continuous gas composition analyzer is not used on the total inlet stream to the flare, then typically, a reporter must determine composition of each stream routed to the flare using an option as specified in 40 CFR 98.233(u)(2), which is also consistent with the current rule. The final rule specifies that for hydrocarbon product streams routed to a flare, a reporter may use a representative composition based on process knowledge and best available data, as specified in 40 CFR 98.233(n)(2)(iii) of the current rule. The final rule specifies procedures for determining composition of emission streams from sources at onshore natural gas processing facilities that are consistent with the 40 CFR 98.233(n)(2)(ii) of the current rule, except that samples must be collected at least annually. According to 40 CFR 98.233(u)(2)(i) and (ii) of both the current and final rule, if a continuous gas composition analyzer is used at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility, then annual average GHG mole fractions developed from the measurement data must be used in flared emissions calculations. Other options for determining GHG composition in current 40 CFR 98.233(u)(2) include using results of sample analysis, use of default values, or use of site-specific values based on engineering estimates, depending on the industry segment. Another current option for determining composition of streams routed to flares from dehydrators and storage tanks is to use the results of process simulations as specified in current 40 CFR 98.233(e)(6) and (j)(5). Our intent is that methods in the final amendments for determining gas composition align with the current requirements, except for the five following additional options and requirements. First, 40 CFR 98.233(n)(4)(ii) in the final amendments provides a new option for determining composition of the combined total stream to a flare based on annual sampling and analysis as an alternative when a continuous gas analyzer is not used on the total stream to the flare. Second, for clarity, all of the requirements for determining composition of streams from individual sources are consolidated in 40 CFR 98.233(n)(4)(iii) rather than being dispersed throughout other sections of the rule. Third, new source-specific options are provided in 40 CFR 98.233(n)(4)(iii)(B)(*1*) to use either process simulation or quarterly sampling and analysis to determine composition of gas streams routed to a flare from acid gas removal units. Fourth, since 40 CFR 98.233(u)(2) requires determination of only the GHG composition, 40 CFR 98.233(n)(4)(iii)(B)(*7*) specifies that composition of ethane, propane, butane, and pentanes plus (for use in equation W–20 to calculate flared CO_2 emissions) must be determined using a representative composition based on process knowledge and best available data. Fifth, when determining composition based on analysis of grab samples in accordance with 40 CFR 98.233(u)(2)(i), the final amendments (40 CFR 98.233(n)(4)(iii)) require that the samples must be collected and analyzed annually, rather than the current requirement in 40 CFR 98.233(u)(2)(i) to use ''your most recent available analysis.'' This change aligns the sampling frequency of individual streams with the sampling frequency specified in the final sampling option for the inlet stream to the flare as discussed previously and is expected to improve data quality and the accuracy of total reported emissions by eliminating the use of outdated data.

Fifth, for clarity, we are finalizing as proposed additional requirements in 40 CFR 98.233(n)(5) to specify how flow and composition data must be used to calculate total emissions depending on different scenarios a reporter could use to determine the flow and gas composition. The final 40 CFR 98.233(n)(5)(i) specifies that if both flow and gas composition are determined for the inlet gas to the flare, then these data are to be used in a single application of equations W–19 and W–20 to calculate the total emissions from the flare. If the flow and gas composition are determined for each of the streams that are routed to the flare, then one of the final options in 40 CFR 98.233(n)(5)(iii) requires the reporter to use each set of stream-specific flow and annual average concentration data in equations W–19 and W–20 to calculate stream-specific flared emissions for each stream, and then sum the results from each stream-specific calculation to calculate the total emissions from the flare. Alternatively, 40 CFR 98.233(n)(5)(iii) allows reporters to sum the flows from each source to calculate the total gas flow into the flare and use the source-specific flows and source-specific annual average concentrations to determine flow-weighted annual average concentrations of CO_2 and hydrocarbon constituents in the combined gas stream into the flare. The calculated total gas flow and the calculated flow-weighted annual average concentrations would then be used in a single application of both equation W–19 and W–20 to calculate the total emissions from the flare. If flow is determined for all of the individual source streams while gas composition is determined for the combined stream into the flare, then 40 CFR 98.233(n)(5)(ii) requires the reporter to sum the individual source flows to calculate the total flow into the flare. This summed volume and the gas composition determined for the combined stream into the flare would be used in a single application of equations W–19 and W–20 to calculate the total emissions from the flare. Finally, 40 CFR 98.233(n)(5)(iv) specifies that a reporter may not calculate flared emissions based on the determination of the total volume at the inlet to the flare and gas composition for each of the individual streams routed to the flare. This combination of volume and gas composition determinations is not allowed because there is no way to calculate flow-weighted average compositions of either the inlet gas to the flare or the individual source streams.

Sixth, we are finalizing as proposed to delete the option to use a default higher heating value (HHV) in the calculation of N_2O emissions and instead require all reporters to use either a flare-specific HHV or individual flared gas stream-specific HHVs in the calculation. In the existing rule, 40 CFR 98.233(n)(7) requires the use of equation W–40 to calculate N_2O emissions from flares. This equation requires the flared gas volume, the HHV of the flared gas, and the use of a default emission factor. For field gas or process vent gas, the variable definition for the HHV provides that either a site-specific or default value may be used; for other gas streams, a site-specific HHV must be used. We are finalizing as proposed in 40 CFR 98.233(n)(8) to require the use of a flare-specific HHV when composition of the inlet gas to the flare is measured or when flow-weighted concentrations of the inlet gas are calculated from measured flow and composition of each of the streams routed to the flare. Similarly, final amendments require reporters to calculate N_2O emissions using flared gas stream-specific HHVs when flow and composition are determined for each of the individual streams that are routed to the flare and emissions are calculated per stream and summed to calculate total emissions from the flare. A change from the proposal is that the final rule also allows the direct measurement of the HHV as an alternative to calculation of the HHV from the composition information. This measurement can be conducted at the inlet to the flare or measurements may be made for each stream and be used in conjunction with the flow estimates for each stream to calculate a weighted annual average HHV. We also finalized as proposed a new requirement in 40 CFR 98.236(n)(9) to report the HHV(s) used to calculate N_2O emissions. This data element will improve verification of reported N_2O emissions and minimize the amount of communication with reporters via e-GGRT. It also will be useful for characterizing the differences in flared gas streams among the various industry segments and basins, and it is expected to be useful in analyses such as updates to the U.S. GHG Inventory.

Seventh, we are finalizing as proposed the changes to the emission calculation requirements for flares that use CEMS because the existing methodology to calculate total GHG emissions when using CEMS is inconsistent with CAA section 136(h) as described in section II.B. of this preamble. Currently, if a reporter operates and maintains a CEMS to monitor emissions from a flare, existing 40 CFR 98.233(n)(8) requires the reporter to calculate only CO_2 emissions from the flare. The final amendments revise existing 40 CFR 98.233(n)(8) (final 40 CFR 98.233(n)(9)) to require reporters to comply with all of the other emission calculation procedures as proposed in 40 CFR 98.233(n), with one exception. The exception is that since CO_2 emissions are measured with the CEMS, calculation of CO_2 emissions using equation W–20 is not required. We expect that these final amendments will address a potential gap in CH_4 emissions reporting and improve the overall quality and completeness of the emissions data collected by the GHGRP, consistent with section II.A. of this preamble.

Eighth, we are finalizing with revisions both the removal of the current source-specific methodologies for calculating flared emissions (*i.e.,* existing 40 CFR 98.233(e)(6) for dehydrators, existing 40 CFR 98.233(g)(4) for completions with hydraulic fracturing, existing 40 CFR 98.233(h)(2) for completions without hydraulic fracturing, existing 40 CFR 98.233(j)(5) for tanks, existing 40 CFR (l)(6) for well testing, and existing 40 CFR 98.233(m)(5) for associated gas) and the addition of a requirement that the reporter use engineering calculations and best available data to disaggregate the calculated total emissions per flare to the source types that routed gas to the flare (40 CFR 98.233(n)(10)). The final amendments require disaggregated emissions to be calculated using engineering calculations and best available data as was proposed; however, the revisions include a requirement that if stream-specific flow and composition for a single source type is used to calculate flared emissions then the source-specific emissions calculated using this data must be used to calculate the disaggregated emissions per source type. Disaggregating the total emissions per flare to the applicable source types that route emissions to the flare will eliminate the disconnect between the sum of source-specific flared emissions versus the total emissions per flare that has occurred under the current approach. This will improve the overall quality and accuracy of total reported emissions from the flare stacks source type, while maintaining acceptable accuracy of estimated flared emissions per source type for use in assessing trends in control over time, policy determinations carrying out provisions under the CAA, and in U.S. GHG Inventory development.

Finally, we are finalizing as proposed the removal of existing 40 CFR 98.233(n)(9). Since the final amendments eliminate the source-specific flared emissions calculation methodologies, as discussed above, the requirement in existing 40 CFR 98.233(n)(9) to subtract source-specific flared emissions from the total emissions per flare is not needed to avoid double reporting of flared emissions under the final amendments.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to the calculation methodologies for emissions from flare stacks.

Comment: Several commenters indicated that subpart W does not properly distinguish between combustion efficiency (CE) and destruction efficiency (DE) (also known as destruction and removal efficiency [DRE]). One commenter asserted that methane emission calculations must be based on destruction efficiency, not combustion efficiency, to account for all methane oxidized whether to CO_2 or CO. One commenter stated that the accurate method to calculate and report CH_4 and CO_2 emissions is to use DE in equation W–19 to calculate CH_4 emissions and to use CE in equation W–20 to calculate CO_2 emissions. This commenter also noted that using only CE in subpart W is inconsistent with other EPA flare regulations such as 40 CFR 63.670(r). One commenter stated that the definition of the CE term in equation W–19 is equivalent to DE in the literature; according to the commenter, this inconsistency will lead to confusion for subpart W reporters because those familiar with flares calculate emissions from DE, not from CE. Another commenter asserted that the EPA must understand the distinction between CE and DE when evaluating studies and literature. Two commenters noted that the EPA should define a relationship between CE and DE. One of these commenters suggested that DE be 1.5 percent higher than CE, as in an EPA publication (''Parameters for Properly Designed and Operated

Flares'')[54] and in regulations. The other commenter summarized the results of two studies that measured and compared CE and DE for numerous flares.[55 56] The commenter developed a correlation between the CE and DE data and suggested that this correlation could be used to calculate DE from measured CE or vice versa with high accuracy.

Response: The proposal used the term combustion efficiency because that is the term used in the existing part 98 regulations. However, we agree with the commenters that there is a difference between destruction efficiency and combustion efficiency, and we agree that destruction efficiency is the value that should be used to calculate CH_4 emissions and combustion efficiency is the correct value to use to calculate CO_2 emissions. Based on consideration of these comments, we have corrected the efficiency terms in equations W–19 and W–20 of the final amendments so that destruction efficiency is used in equation W–19 to calculate CH_4 emissions and combustion efficiency is used in equation W–20 to calculate CO_2 emissions.

We also agree with commenters that the default combustion efficiencies in the three proposed tiers (40 CFR 98.233(n)(4)(i) through (iii) of the proposal) are actually destruction efficiencies, and we agree that a relationship between combustion efficiency and destruction efficiency should be included in the rule. We believe the relationship in ''Parameters for Properly Designed and Operated Flares'' (*i.e.,* destruction efficiency is 1.5 percent higher than destruction efficiency over the full range of destruction efficiencies) is the most appropriate relationship at this time. This relationship has a history of more than 10 years acceptance by the EPA, it is used in other regulations such as NESHAP CC, and it is simple to implement. However, we believe the correlation equation suggested by one commenter shows promise for future consideration, especially since it appears the difference between combustion efficiency and destruction efficiency increases at lower destruction efficiencies. As discussed in the response to the following comment in this section, we are finalizing with some modifications from proposal the three tiers, and after consideration of these comments and the EPA's reassessment of the terms used in the proposal, we are specifying both default destruction efficiencies that are consistent with the proposed combustion efficiencies and default combustion efficiencies that are 1.5 percent less than the default destruction efficiencies. These changes will result in more accurate emissions calculation and reporting, though we note that the calculated CO_2 emissions will be slightly lower under the final amendments relative to emissions calculated based on the proposed methodology.

Comment: Numerous commenters strongly opposed the proposed revisions that would require reporters to calculate emissions from flares using only one of three default flare combustion efficiencies that are correlated to the type of flare monitoring that they conduct.[57] The commenters primary objection was that the proposed requirement to use only a default efficiency is that it does not allow reporters to use higher efficiencies that can be demonstrated based on empirical data. Commenters also asserted that reporters should not be limited to the proposed defaults because flares generally achieve destruction efficiencies of 98 percent when operating within the parameters of 40 CFR 60.18 and studies have shown that many flares achieve a destruction efficiency considerably higher than 98 percent. One commenter stated that the 95 percent emission reduction required under NSPS OOOOa and proposed under NSPS OOOOb and EG OOOOc was designed to allow operators to use other control options beyond flare combustion devices.

To address their objections, the commenters stated that the EPA should either replace or modify the proposed tiered system of default combustion efficiencies with various alternatives. A majority of the commenters stated that the EPA should allow reporters to use efficiencies based on manufacturer guarantees and/or to use efficiencies in existing federal or state rules that also apply to the flares. A few commenters stated that reporters should be allowed to use efficiencies consistent with the efficiencies required in federal or state operating permits or to use state-approved efficiencies for specific flare models that have been tested by the flare manufacturer. Some commenters stated that the EPA should allow the use of direct measurement of efficiencies using existing or future advanced technologies (*e.g.,* simplified Video Imaging Spectro-Radiometry (VISR)) once the technology has been vetted by a regulatory agency. One commenter stated that the EPA should allow the use of efficiencies obtained based on direct measurement using advanced direct measurement methods that the EPA has used for inspection and compliance purposes. Two commenters stated that reporters should be allowed to use efficiencies based on the results of parametric monitoring. One of these commenters described an approach based on computational fluid dynamics data from ultrasonic flow meters that is analyzed by an artificial intelligence technique into a numerical model to calculate combustion efficiency. One commenter stated that reporters should be allowed to use efficiencies obtained from performance tests for vapor combustors, enclosed flares, and thermal oxidizers. Another commenter noted that the proposed Tier 2 did not cross-reference the NSPS OOOOb provision that allows a facility to determine compliance with NSPS OOOOb based on the results of manufacturer testing of enclosed combustion devices. Another commenter stated that reporters should be allowed to use (OTM–52) to determine destruction efficiency or combustion efficiency of enclosed combustion devices. To prevent inconsistent reporting between subpart W and other EPA programs, one commenter stated that reporters should be allowed to use a default destruction efficiency of 98 percent for flares that are designed and operated according to 40 CFR 60.18, and that a 98 percent destruction efficiency also should be allowed for other flares that are operated within New Source Review permit compliance requirements.

Response: Based on consideration of the comments, the proposed default combustion efficiencies (finalized as destruction efficiencies as explained in the response to the preceding comment) are being finalized as options with some changes from the proposal. An additional option is being finalized (40 CFR 98.233(n)(1)(iv)) that allows for improved alignment with the NSPS program whereby an owner or operator can use an alternative test method that

[54] *Id.*

[55] Allen, D. and Torres, V. *TCEQ 2010 Flare Study Final Report.* The University of Texas at Austin. The Center for Energy and Environmental Resources. Prepared for TCEQ. August 1, 2011. Available at *https://www.tceq.texas.gov/airquality/stationary-rules/stakeholder/flare_stakeholder.html* and in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[56] Providence Photonics, LLC. Comments on Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems. Data in Exhibit 1 (CBI).

[57] Although the proposal specified only combustion efficiencies, some commenters referred to destruction efficiencies, consistent with their comments that are described in the preceding comment summary. In this comment summary we refer to destruction efficiencies when that is the term that was used by commenters. We use the term ''efficiency'' when some commenters referred to combustion efficiency and others referred to destruction efficiency.

has been submitted to and approved by the EPA under 40 CFR 60.8(b), as outlined in 40 CFR 60.5412b(d) or 60.5412c(d) to demonstrate a greater combustion efficiency based on empirical data and utilize the results to calculate flared emissions under subpart W. The submitter must demonstrate to the satisfaction of the EPA under 40 CFR 60.8(b) that the alternative test method, when implemented as presented in the request for approval, including all documented monitoring protocols, continuously demonstrates compliance with a combustion efficiency of 95 percent or greater. Under NSPS OOOOb, or a state or Federal Plan in 40 CFR part 62 implementing EG OOOOc, a submitter may demonstrate compliance either through continuous measurement of combustion efficiency or through continuous measurement of the net heating value of the combustion zone and the net heating value dilution parameter (if the flare uses perimeter assist air). Note, however, that only alternative test methods based on continuous measurement of combustion efficiency will be allowed under subpart W because the purpose of allowing the alternative test method is to enable reporters to identify specific destruction and combustion efficiencies that differ from the defaults; the option based on continuous measurement of the net heating values does not result in a specific combustion efficiency. Likewise, if the submitter is using the alternative test method to document combustion efficiencies greater than 95 percent, they would need to provide sufficient documentation for how this was determined and the uncertainties associated with the measurement. When the EPA approves an alternative test method, the approval may be site-specific or it may become broadly applicable, approved for a class of flares such that reporters for all flares meeting the requirements outlined in the alternative test method may use the actual demonstrated combustion efficiency (and an assumed destruction efficiency 1.5 percent higher than the combustion efficiency) to calculate flared emissions under subpart W, provided they also implement inspections and monitoring that are part of the approved alternative test method. This alternative provides owners and operators a pathway to gain approval to directly measure efficiency using advanced measurement technology or other methods that may be approved for a destruction efficiency higher than default values specified under the three tiers. The alternative also aligns the flare emissions calculation methodology with the directives in CAA section 136(h) that reported emissions be based on empirical data that accurately reflect the total emissions, consistent with section II.B. of this preamble.

We agree with the commenter that pointed out the proposed Tier 2 requirements should include a cross-reference to the applicable section in NSPS OOOOb that specifies performance test requirements for enclosed combustion devices in NSPS OOOOb (*i.e.,* a subset of the total flare population under subpart W). This oversight has been corrected in 40 CFR 98.233(n)(1)(ii)(A) and 40 CFR 98.233(n)(1)(ii)(C) of the final amendments by including cross-references to 40 CFR 60.5413b(b) and (d) that require facilities to either conduct testing of enclosed combustion devices themselves or have testing conducted by the enclosed combustion device manufacturer. When the test demonstrates a destruction efficiency of 95 percent or greater, and monitoring parameter values, including those that must be established during the test, are within the specified ranges, then the reporter may use the Tier 2 default efficiencies.

We have also evaluated the suggestion by a commenter to allow the use of OTM–52 as an alternative to the performance testing requirements in NSPS OOOOb. OTM–52 is a draft method that is less costly and easier to implement than the reference method in NSPS OOOOb. It is used to determine combustion efficiency rather than destruction efficiency. It has not been approved as an alternative to the test method in NSPS OOOOb and thus, it may not be used to test an enclosed combustion device that is subject to NSPS OOOOb. Similarly, it has not been approved as an alternative to the test method in EG OOOOc and thus, may not be used to test an enclosed combustion device that is subject to a state or Federal Plan in 40 CFR part 62 implementing EG OOOOc. However, for enclosed combustion devices that are not subject to NSPS OOOOb or state or Federal Plans in 40 CFR part 62 implementing EG OOOOc that require 95 percent reduction in methane emissions, we believe it provides an acceptable level of accuracy for the purposes of calculating emissions using the Tier 2 default efficiencies when a test results in a combustion efficiency of 93.5 percent or greater. Therefore, OTM–52 is included in 40 CFR 98.233(n)(1)(iv) of the final amendments as an alternative to the Tier 2 performance testing procedures for enclosed combustion devices that are not subject to NSPS OOOOb or a state or Federal Plan in 40 CFR part 62 implementing EG OOOOc.

We have not included other methods suggested by the commenters for demonstrating flare efficiencies to use in calculating emissions under subpart W (*e.g.,* manufacturer guarantees, presumption that operation according to 40 CFR 60.18 ensures 98 percent destruction efficiency, parametric monitoring, state-approved efficiencies, or efficiencies in permits) because we have determined that they do not provide a reasonable assurance that the stated efficiency would be continuously met or we do not have data available at this time needed to implement such methods and to verify the results. Specifically, with respect to the commenter's assertion that flares operated according to 40 CFR 60.18 should be allowed to use a 98 percent destruction efficiency, we note that the General Provisions at 40 CFR 60.18 state that the referencing subpart will specify the monitoring requirements and that 40 CFR 60.18 on its own does not ensure a properly operating flare. In the supplemental proposal to NSPS OOOOb,[58] we noted that recent studies suggest that 10 percent of flares in the Permian basin are either unlit or are only burning a portion of the gas sent to the flare[59] and that the current operating and monitoring practices and requirements for well sites and centralized production facilities are not adequate to ensure flare control systems are operated efficiently. Therefore, under the final NSPS OOOOb provisions, we have finalized compliance requirements to ensure all aspects of the General Provisions at 40 CFR 60.18 are met at all times. These provisions are cross-referenced in subpart W to provide assurance that a 95 percent destruction efficiency is accurate for the flare. Flares that are not operated properly cannot be reasonably assured to have the claimed destruction efficiency. Without assurances that the flare is being operated properly, it is our assessment that a destruction efficiency associated with a properly functioning flare (*i.e.,* 95 percent or higher) would be inappropriate and not ensure accurate total emissions reported. Similarly, with respect to the commenter's assertion that destruction efficiencies be based on a manufacturer's guarantee, the

[58] See 87 FR 74793 (December 6, 2023).

[59] Permian Methane Analysis Project (PermianMAP) reporting the results of 4 Environmental Defense Fund (EDF) surveys of over a thousand flare stacks from February to November 2020. See *https://www.permianmap.org/flaring-emissions.*

guarantees alone would not ensure that the flares are being operated properly and that those destruction efficiencies accurately reflect actual operation of the flare. We expect that a 95 percent destruction efficiency will be a reasonably accurate average destruction efficiency for a properly operated flare, considering that there will be periods during which the flare is unlikely to meet a higher manufacturer claimed destruction efficiency, due to operating conditions, *e.g.,* high cross-winds. Therefore, at this time, we have not included additional alternative methods or destruction efficiencies. For additional comments and response on alternatives to the proposed destruction efficiencies, see section 15 of the *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule*, available in the docket to this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

Comment: Numerous commenters claimed that the proposed 92 percent destruction efficiency [60] for Tier 3 was too low because the value in the cited study [61] included unlit flares. According to the commenters, since emissions from unlit flares would be calculated separately under the proposal, including them in the Tier 3 destruction efficiency would result in double counting of the emissions.

Response: Table 1 in the Plant *et al.* (2022) study reported both observed flare DREs and total effective DREs for flares in three basins. The total effective DREs are based on both the observed flare DREs (from lit flares) plus the percentage of unlit flares obtained from a separate study. However, the 92 percent destruction efficiency for Tier 3 is based on the mean observed flare DRE for the Permian basin rounded up from 91.7 percent to 92 percent; it is not based on the reported overall average total effective DRE of 91.1 percent. Thus, the final Tier 3 destruction efficiency of 92 percent does not double count emissions for unlit flares.

We have determined that the average observed destruction efficiency of 92 percent is a reasonable combustion efficiency for subpart W sources that are not monitoring as specified under Tier 1 or Tier 2 because the overall average in the empirical results likely included many facilities with higher performing flares that would likely comply with one of those tiers and thus should be excluded from the calculation of the average for Tier 3 flares. We agree that it is important to allow for submission of empirical data, as appropriate; therefore, as discussed in the previous response, we have added an option to use that allows for improved alignment with the NSPS program whereby an owner or operator can use an alternative test method that has been submitted to and approved by the EPA under 40 CFR 60.8(b), as outlined in and 40 CFR 60.5412b(d) or 60.5412c(d). The final default destruction efficiencies and alternative option align with the directives in CAA section 136(h) that reported emissions be based on empirical data that accurately reflect the total emissions, consistent with section II.B. of this preamble.

Comment: Commenters stated that the rule should allow monitoring of the presence of a pilot flame using visual observation with a video camera, and one commenter noted that this approach would more efficiently utilize manpower and potentially result in more timely discovery and correction of unlit or malfunctioning flares. Commenters asserted that subpart W should allow the use of auto-ignitors instead of requiring continuous pilots. They noted that states such as Texas and New Mexico allow auto-ignitors, and they pointed out that use of such devices eliminates the need for a continuous pilot, thereby reducing the amount of pilot and sweep gas needed to operate the flare. One commenter requested that the EPA allow the use of the VISR device to monitor the presence of pilot flame.

Response: We agree that the use of video cameras and advanced remote measurement options are viable means for detecting the presence or absence of a pilot flame, and these options have been added in 40 CFR 98.233(2)(i) of the final amendments. We have not allowed the use of auto-ignitors as an alternative to maintaining a continuous pilot flame in the final amendments. In response to comments on NSPS OOOOb requesting that auto-ignitors be allowed in that rule, we explained that there is not sufficient data currently to suggest that electronic ignition systems on combustion devices are capable of continuously supplying a constant source of ignition adequate to keep a flame present on a continuous basis. Our reply to comments on NSPS OOOOb also indicated that the EPA does not have sufficient information on the degradation of electronic ignition systems or how to ensure these systems maintain functionality over time. Additionally, our reply noted that operating a flare with a continuously lit pilot adds an additional degree of flame stability to the flare itself, and we do not have sufficient information on whether the sporadic lighting of the combustion device tip would lead to flame instability, and by extension, poor combustion.[62 63] We maintain these same views and assessments in this final rulemaking regarding this commenter's suggestion for the subpart W regulations. Thus, auto-ignitors are not allowed in subpart W due to the uncertainty regarding the effect they may have on the destruction efficiency and combustion efficiency of the flare.

Comment: One commenter recommended revising the pilot flame monitoring requirements to allow the use of multiple or redundant monitoring devices or inspection techniques. According to the commenter, monitoring device malfunctions are not uncommon and an operator should have the option to confirm whether a monitoring result is errant and not include the time as unlit if other monitoring/inspection information demonstrates the output of the device to be incorrect.

Response: We note that the proposed amendments did not prohibit the use of multiple pilot flame monitoring devices, but we agree with the commenter that it would be appropriate to explicitly state in subpart W that this is allowed. This provision has been added in 40 CFR 98.233(n)(2)(i)(B) of the final amendments. We also included a requirement that when there is a discrepancy in the output of multiple devices that the operator must either visually confirm or use video surveillance output to confirm that the flame is present as soon as practicable after detecting the discrepancy to ensure that at least one device is operating properly. If at least one device is confirmed to be operating properly, then the operator may continue to rely on the

[60] The proposal incorrectly stated that the 92 percent efficiency for Tier 3 was the combustion efficiency. As discussed in the response to a preceding comment, the 92 percent should be the destruction efficiency. In this comment summary we refer to the efficiency as destruction efficiency to reflect the accurate terminology.

[61] Plant, G., *et al.* 2022. ''Inefficient and unlit natural gas flares both emit large quantities of methane.'' Science, 377 (6614). *https://doi.org/10.1126/science.abq0385.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[62] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews 40 CFR parts 60 and 63 Response to Public Comments on Proposed Rule August 23, 2011 (76 FR 52738). P. 308. in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[63] EPA's Responses to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources May 2016. P. 11–190. in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

properly operating device(s) for monitoring the pilot. By ''discrepancy'' we mean one or more devices indicate the flare is unlit while one or more other devices indicate it is lit. We do not mean cases in which two or more devices provide different output values, but all values confirm the flare is lit. For example, two thermocouples that register different temperatures, either of which confirms the flare is lit, does not constitute a discrepancy for this purpose under subpart W.

Comment: Commenters opposed the proposed requirement to measure flow using flow meters or parameter monitoring systems combined with engineering calculations. The most commonly stated objections were that most flow meters are inaccurate on low-pressure streams and streams with low or intermittent flow that are common in the upstream and midstream industry segments, and the cost to install meters would be excessive. Commenters also noted that many flares are located at sites that lack electrical power, SCADA systems, WiFi and cellular coverage, and field offices. One commenter noted that process simulation is approved for determining flow to use in calculating vented emissions, and it seems inconsistent to disallow the same methods for determining flow to flares. One commenter asserted that field testing shows parametric monitoring overestimates flow volumes, and one commenter stated that it can be difficult to calibrate flow meters on variable flow streams.

Instead of requiring continuous measurement of flow, most of the commenters recommended retaining the current requirements that require use of measurement data only when a continuous flow measurement device is used to measure total or partial flow to the flare and to allow engineering calculations based on process knowledge, company records, and best available data when flow is not measured using a continuous flow measurement device. A few commenters stated that process simulation should be allowed, particularly for streams from dehydrators and tanks. One commenter stated that engineering calculations should be allowed, particularly for blowdown events that are from equipment with defined volumes and known temperatures and pressures. One commenter recommended that the rule be revised to allow use of a remote measurement method to measure flow rate.

Response: After consideration of these comments, we agree with the comments that methods that are allowed for determining flow of vented emissions should also be allowed to determine flow to a flare, that in some cases, such as for streams to low pressure flares, modeling may produce flow estimates for the purposes of estimating annual greenhouse gas emissions with accuracy similar to measurements using flow meters. We also agree with commenters that the proposal underestimated the costs of monitoring and that remote sites may not have access to grid electricity needed to power the meters and other measurement devices. Based on these considerations, the final amendments specify options for determining flow based on slightly modified versions of the proposed continuous parameter monitoring options (40 CFR 98.233(n)(1)(i) and (ii) as proposed) that align more closely with current requirements as well as new options that also are more closely aligned with options in the current rule.

The proposed option to measure flow of the total inlet stream to the flare was finalized with two changes from proposal (40 CFR 98(n)(3)(i)). One change was to add a sentence specifying that measured flow must be used in calculating the flared emissions if a continuous parameter monitoring system is used. This requirement was added since the final amendments include options other than the continuous monitoring options, and a facility may not elect to calculate emissions based on one of the other options if they have measured volumes. This change is consistent with the requirements in 40 CFR 98.233(n)(1) of the current rule. The second change was to add a requirement to use engineering calculations based on best available data and company records to calculate pilot gas flow to add to the total gas flow to the flare. This requirement was added because we realized that we had inadvertently neglected to include a requirement for determining pilot gas flow in the proposal. This change also makes the final option consistent with the requirement in 40 CFR 98.233(n)(1) to determine flow for ''all of the flare gas.''

The final amendments also specify several options for determining the flow of individual streams that are routed to the flare. The proposed option to use a continuous parameter monitoring system was finalized as proposed (40 CFR 98.233(n)(3)(ii)(A)), except that a sentence was added specifying that measured flow must be used in calculating the flared emissions if a continuous parameter monitoring system is used. This sentence was added for the same reason noted above for adding it to the option for using a continuous parameter monitoring system to measure total inlet flow to the flare.

The final amendments also include new options to determine flow using process simulations, engineering calculations, and emission factor methods consistent with methods specified for determining vented emissions for sources whose flared emissions are required to be disaggregated. The applicable options are specified in separate paragraphs for each source type for which subpart W specifies methods for determining flow of vented emissions (40 CFR 98.233(n)(3)(ii)(B)(*1*) through (7)). Additionally, for source types that are subject to flare-specific reporting in the current rule (*e.g.,* dehydrators, completions, tanks, well testing, associated gas), these options are consistent with the requirements in the current rule for determining the volume of gas routed to flares. For other source types, including new source types subject to reporting for the first time under these amendments (*e.g.,* crankcase venting) and sources that do not have methods for calculating vented emissions in subpart W, 40 CFR 98.233(n)(3)(ii)(B)(*8*) of the final amendments specifies that flow to the flare may be calculated using engineering calculations based on process knowledge, company records, and best available data. Additionally, since some of the methods for calculating vented emissions calculate only the flow of GHGs, 40 CFR 98.233(n)(3)(ii)(B)(*8*) of the final amendments also specifies that the flow of the non-GHG portion of the streams routed to the flare also must be based on process knowledge, company records, and best available data.

We have not included an option in the final rule to determine flow using the VISR advanced remote sensing method suggested by one commenter because we do not have sufficient information on the applicability and effectiveness of the method for determining flow over the range of conditions expected at facilities in the oil and gas industry. The study cited in the commenter's letter evaluated the method for a single steam-assisted flare at a research facility using natural gas as the flared gas. It is not clear from this study how the method would be implemented and perform when used for other types of flares and when the flared gas includes other hydrocarbons in addition to methane and the composition varies with time. The method also provides flow only of the combustible constituents in the flared gas, which means procedures for converting to total volume would need to be specified in the rule so that the flow could be used to calculate emissions using equations W–19, W–20, and W–40, or the rule would need separate procedures for calculating emissions when using this method. The paper summarizing the results of the study also noted that the method is less accurate when the combustion efficiency is low. The EPA intends to further evaluate this method as additional information becomes available and may consider including an option based on this method in a future rulemaking.

Comment: One commenter supported the proposed approach that provided a choice between using a continuous gas analyzer or conducting periodic compositional analysis. However, numerous commenters opposed the proposed composition measurement requirements for a variety of reasons. The most commonly cited reasons for opposition were that the composition of produced gas is relatively stable so frequent sampling will not significantly improve accuracy of emissions calculations and that the requirement would add significant costs and not be cost effective. Some commenters indicated that there would be logistical challenges to quarterly sampling because only a limited number of labs are capable of conducting the required analyses, and there would be logistical challenges to the use of continuous composition analyzers including installation of sample ports, calibration and maintenance of the thousands of meters, and lack of infrastructure and field connectivity. One commenter added that requiring compositional monitoring would further exacerbate ongoing COVID-related supply chain delays. Other commenters asserted that there are technical challenges to collecting samples in low-pressure lines with intermittent flows, and one commenter stated that it is difficult to calibrate composition analyzers on such streams. One commenter stated that it is inconsistent to require analysis of streams routed to flares when such analysis is not required for calculating vented emissions from the same source types. One commenter stated that sampling sour gas streams would pose a safety risk due to the presence of high H2S concentrations. One commenter objected to the proposed analysis requirements because they go beyond the continuous NHV monitoring or demonstration under proposed NSPS OOOOb and EG OOOOc. One commenter asserted that the proposed annual sampling of purge gas, sweep gas, and auxiliary fuel would pose undue burdens on operators for stream that will not significantly impact emissions reported under subpart W.

Instead of requiring continuous gas composition analyzers or periodic sampling and analysis, nearly all of the commenters stated that the current requirements should be retained. Many of these commenters specifically indicated that the final rule should allow the current option to determine composition using process simulations. Other commenters stated that the final rule should include the current options for using engineering calculations, best available data, or representative sampling. Two commenters suggested that the frequency of conducting analysis of representative samples should be at least annually. If quarterly sampling is retained in the final amendments, two commenters requested that the rule also include a provision allowing companies to reduce the frequency after some period of showing that the composition is stable. One commenter stated that sales gas composition should be allowed for pilot/assist gas. Another commenter requested that the sampling of purge gas, sweep gas, and auxiliary fuel be made voluntary or required only if the volume exceeds a specified threshold.

Response: After consideration of the public comments, we agree with the commenter that asserted methods allowed for determining composition of vented emissions should also be allowed to determine composition of streams routed to a flare. We also agree with commenters that the proposal underestimated the costs of monitoring. Based on these considerations, the final amendments include additional options for determining composition based on process simulation and engineering calculations as well as the continuous gas composition monitoring and periodic sampling and analysis options that are finalized with some changes from proposal.

The final amendments include two options for determining composition of the total inlet stream to the flare that include some changes from proposal (40 CFR 98.233(n)(3)(i) and (ii)) as proposed). One option, in 40 CFR 98.233(n)(4)(i) of the final amendments, finalizes the proposed option to use a continuous gas composition analyzer on the total inlet stream to the flare. As in the current rule, the final amendments specify that measured compositions must be used in calculating emissions when a continuous gas composition analyzer is used. The second option, to conduct quarterly sampling and analysis of the total inlet stream to the flare, is finalized in 40 CFR 98.233(n)(4)(ii) with several changes from proposal. One change is that the minimum sampling frequency is reduced to once per year. A second change is the proposed requirement to calculate flow-weighted annual averages was not finalized because the flow determinations do not necessarily align with the composition measurements. Finally, there is no need for the proposed requirement to calculate an annual average if only one sample is analyzed during the year. Instead, the final amendments require calculation of an annual average per constituent if more than one sample is analyzed during a year. These changes will lower costs of the final amendments relative to the proposal. Commenters did not provide data to support their contention that the composition of flared streams is relatively stable, and other data to support or refute this position are also unavailable. However, we reduced the minimum required sampling and analysis frequency for this option from quarterly to annually for the final amendments to be consistent with the current frequency specified in 40 CFR 98.233(u)(2)(ii) for onshore natural gas processing plants to determine composition of feed natural gas for calculating vented emissions from sources upstream of the demethanizer or dew point control if they do not determine composition of feed natural gas using a continuous gas composition analyzer. We believe this will provide acceptably accurate data to use in calculating emissions.

The final amendments also include several options for determining composition of individual emission streams routed to a flare. One option, specified in 40 CFR 98.233(n)(4)(iii)(A) of the final amendments, is to use a continuous gas composition analyzer. This option is finalized with several changes since proposal. The proposed option (40 CFR 98.233(n)(3)(iii) as proposed) would have required sampling of purge gas, sweep gas, and auxiliary fuel at least annually. This proposed requirement was not finalized as part of the final continuous gas composition analyzer option because sampling requirements are specified as a separate option for individual streams as discussed below. We also did not finalize the proposed requirement to determine flow-weighted annual average concentrations because flow determinations are not necessarily obtained on the same time intervals as the composition measurements. Consistent with the requirements for continuous gas composition analyzers used on the total inlet stream to a flare, the measured mole fractions must be used to calculate annual average concentrations for each constituent to use in calculating flared emissions if a continuous gas composition analyzer is used.

A new option in the final amendments for determining composition of individual streams from dehydrators, hydrocarbon liquid and produced water storage tanks, and acid gas removal units is to use process simulation software in the same manner that is specified for determining composition of vented streams from these sources. These options are specified in 40 CFR 98.233(n)(4)(iii)(B)(*1*) through (*3*) of the final amendments. These options are included in the final amendments so that a facility may use the same procedures for determining composition of streams routed to flares that are also specified for determining composition of vented streams from the same source types. Another new option in 40 CFR 98.233(n)(4)(iii)(B)(*4*) of the final rule specifies requirements for determining composition of streams routed to flares from various emission sources at onshore production facilities, consistent with 40 CFR 98.233(n)(2)(ii) of the current rule. Finally, a new option in 40 CFR 98.233(n)(4)(iii)(B)(*6*) of the final rule specifies procedures for determining composition of hydrocarbon product streams, consistent with 40 CFR 98.233(n)(2)(iii) of the current rule.

The fourth proposed option was to analyze quarterly samples of individual streams from emission source types and to analyze annual samples of sweep gas, purge gas, and auxiliary fuel (40 CFR 98.233(n)(3)(iv) as proposed). Based on consideration of comments, this proposed option has not been finalized as proposed, but the concept of conducting individual stream sampling is incorporated into the more expansive new options in 40 CFR 98.233(n)(4)(iii)(B)(*1*) through (*3*) of the final amendments for determining composition of streams routed to flares from dehydrators, hydrocarbon liquid and produced water storage tanks, and acid gas removal units. These options specify that composition may be determined using procedures in 40 CFR 98.233(u)(2) for the applicable industry segment, with two exceptions. The first exception is that when use of a continuous gas analyzer is specified in 40 CFR 98.233(u)(2), it means the continuous gas analyzer requirements specified in 40 CFR 98.233(n)(4)(iii)(A) of the final amendments. This change will ensure consistent application of continuous gas composition analyzer requirements to all sources in all industry segments. The second exception is that when 40 CFR 98.233(u)(2)(i) specifies using ''your most recent available analysis'' to determine composition, the final amendments require using annual samples. The current rule also requires onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities to determine composition using the procedures in 40 CFR 98.233(u)(2)(i). However, requiring annual sampling in the final amendments instead of the current requirement to use the most recent available analysis will help ensure the use of representative samples, and the requirement for sampling annually was specified to be consistent with the annual sampling frequency for other streams as discussed previously. Similarly, for streams from any source type other than those identified in 40 CFR 98.233(n)(4)(iii)(B)(1) through (4), including sweep, purge, and auxiliary fuel, 40 CFR 98.233(n)(4)(iii)(B)(5) in the final amendments also specify that composition may be determined using the applicable procedures in 40 CFR 98.233(u)(2). Finally, since the procedures in 40 CFR 98.233(u)(2) require determination of only the GHG composition, 40 CFR 98.233(n)(4)(iii)(B)(*7*) in the final amendments requires determination of representative compositions of ethane, propane, butane, and pentanes plus based on process knowledge and best available data, consistent with requirements in 40 CFR 98.233(n)(2)(iii) of the current rule.

Comment: One commenter indicated that operators should have the opportunity to measure flare gas HHV directly using, for example, continuous gas analyzers or by using a sound speed methodology from an ultrasonic flowmeter. The commenter noted that this latter method can provide reliable real-time measurement, is highly accurate, can be implemented with minimum cost, and is easy to maintain. The commenter cited a specific patent ''Online Analyzers for Flare Gas Processing'', which describes a system that has been used successfully in the field.[64]

Response: The EPA agrees with the commenter that direct measurement of the HHV should be allowed in addition to the calculation of HHV from concentration data and the final provisions have been changed from proposal accordingly. In 40 CFR 98.233(n)(8), the final rule specifies that the annual average HHV may be directly measured using a calorimeter or by using a continuous gas composition analyzer that automatically calculates the HHV based on the measured composition. In addition to direct measurement methods, the final rule also specifies that annual average HHV may be calculated based on the annual average compositions determined using continuous gas composition analyzers, periodic sampling and analysis, or process simulation or engineering calculations. As discussed in a previous response in this section, the periodic sampling and analysis for gas composition must be at least annually in the final rule as opposed to at least quarterly in the proposed rule. Another previous response in this section provides information regarding the addition of process simulation and engineering calculation options for determining composition in the final rule.

The final rule, however, does not cite the specific methodology described by the commenter. With regard to the patent mentioned, the EPA agrees that it appears to be an efficient method to continuously measure the net heating value of a gas stream. However, no information was provided regarding how this would be converted to HHV as required by the rule.

Comment: One commenter recommended that the EPA should also require reporters that elect to be in Tier 1 or Tier 2 to keep and maintain records consistent with the recordkeeping requirements under the respective NESHAP CC, NSPS OOOOb, and approved state plan requirements. For Tier 1, the commenter recommended including the recordkeeping requirements under 40 CFR 63.655(i)(9); for Tier 2 the commenter recommended including the recordkeeping requirements consistent with 40 CFR 60.5420b(c)(3)(ii)(A) through (H). According to the commenter, maintaining such records will allow EPA staff to verify additional compliance with the respective flare requirements to ensure more accurate emissions reporting.

Response: The EPA agrees with the commenter that additional recordkeeping is needed to ensure that facilities that are not subject to the NESHAP CC or NSPS OOOOb but elect to comply with the Tier 1 or Tier 2 efficiencies are achieving the applicable efficiencies for purposes of the subpart W calculation methodology. Thus, the EPA has strengthened recordkeeping

[64] US Patent Pub. No.: US 2022/0107289 A1. April 7, 2022. Available at: *https://patentimages.storage.googleapis.com/6b/46/97/d1524f32c62da7/US20220107289A1.pdf.*

requirements in the final rule for facilities complying with the Tier 1 or Tier 2 efficiencies to align with the recordkeeping requirements for flares in NESHAP CC and NSPS OOOOb, respectively. Specifically, for Tier 1, 40 CFR 98.233(n)(1)(i) requires compliance with the recordkeeping requirements in 40 CFR 63.655(i)(2) and (3) for enclosed combustion devices and 40 CFR 63.655(i)(9) for open flares. For Tier 2, 40 CFR 98.233(n)(1)(ii)(A), (B), and (C) require compliance with the recordkeeping requirements in 40 CFR 60.5420b(c)(11).

For Tier 2, the commenter cited the recordkeeping requirements in 40 CFR 60.5420b(c)(3)(ii)(A) through (H) of the December 6, 2022, Supplemental Proposal. These sections have been rearranged in the final NSPS OOOOb making it difficult to determine exactly which recordkeeping requirements in the final NSPS OOOOb the commenter would recommend including in subpart W. However, some of the provisions in the sections cited by the commenter involved records of certifications (*e.g.,* for closed vent systems or to document why it is infeasible to comply with associated gas recovery requirements), records of periods of temporary venting of associated gas, records of bypass monitoring, and closed vent system inspection records that we have not included in the final subpart W. Requirements to certify both closed vent system inspections and reasons for why it is infeasible to comply with associated gas recovery requirements and related recordkeeping requirements are not included in this rulemaking because subpart W is an emissions reporting rule, not an emissions control rule. Records related to associated gas venting are not addressed in 40 CFR 98.233(n) because the methodology for calculating vented associated gas emissions, including temporary venting of streams that are normally flared, is specified in 40 CFR 98.233(m) of the final rule. The final rule does not require facilities that elect to comply with the Tier 2 efficiencies to implement NSPS OOOOb bypass device and closed vent system requirements, including related recordkeeping requirements. These requirements are included in NSPS OOOOb to ensure that the emission standards for emission source types are met, but these provisions are not needed to ensure the efficiency of the flare is met for the portion of the flow from a source that is routed through the flare. However, if there are leaks from a closed vent system or a bypass device diverts flow from entering a flare, then those volumes cannot be assumed to be controlled by the flare. Therefore, for a facility that measures or calculates flow volumes routed to flares from individual sources (instead of measuring the total flow at the flare inlet), 40 CFR 98.233(n)(3)(ii) in the final rule specifies that the closed vent system leaks and bypass volumes must be calculated based on engineering calculations, process knowledge, and best available data and subtracted from the measured or calculated flow volumes from the applicable sources to determine the flow routed to the flare. The final rule also specifies that the estimated closed vent system leaks and bypass volumes must be used in the calculation and reporting of vented emissions from the applicable sources. These requirements will ensure that the closed vent system leaks and bypass emissions are properly estimated, consistent with the directive under CAA section 136(h) to ensure that reporting under subpart W accurately reflects total methane emissions. We have also included a harmonizing reporting requirement in 40 CFR 98.236(n)(11) of the final rule for reporters to indicate whether the reported volumes for each stream from an individual source has been adjusted to account for closed vent system leaks or bypass volumes. In the EPA's verification process, this information is expected to help identify facilities that should report vented emissions from sources that also report flared emissions. Finally, the recordkeeping requirements specific to flare design and operation in 40 CFR 60.5420b(c)(11) are cross-referenced from 40 CFR 60.5420b(c)(3). Thus, since these are the only NSPS OOOOb recordkeeping requirements that are included in the final rule, we have directly cross-referenced the recordkeeping requirements in 40 CFR 60.5420b(c)(11) from 40 CFR 98.236(n)(3)(ii) of the final rule.

2. Reporting Requirements for Flared Emissions

a. Summary of Final Amendments

The EPA is finalizing several changes to the reporting requirements for flares. These changes are to align reporting in 40 CFR 98.236(n) with the final revisions to the calculation methods specified in 40 CFR 98.233(n), consistent with section II.B. of this preamble, and to improve the verification process, obtain a better understanding of the design and operation of flares in each of the industry segment to help future policy determinations, and clarify ambiguous provisions.

First, the EPA is finalizing as proposed the replacement of the source-specific flared CH_4, CO_2, and N_2O emissions reporting requirements currently in 40 CFR 98.236(e), (g), (h), (j), (k), (l), (m), and (n) with a requirement to disaggregate total reported CH_4, CO_2, and N_2O emissions per flare to the source types that routed gas to the flare as described in section III.N.1. of this preamble. The total emissions per flare must be disaggregated to the source types specified in 40 CFR 98.236(n)(19). The source types listed in 40 CFR 98.236(n)(19) include all of the source types for which flared emissions currently must be reported, except that flared emissions from condensate storage tanks must be included in the collective emissions from ''other'' flared sources rather than being disaggregated separately. Additionally, the final amendments, as proposed, require disaggregation of flared emissions that are attributable to AGR vents (flared emissions from NRU vents must be included in the category of ''other'' flared sources). In addition to aligning the reporting with the final calculation methodology, reporting the disaggregated emissions per flare rather than per facility, sub-basin, or county (as currently required), and rather than per well-pad site, gathering and boosting site, or facility (as is required in the final amendments for vented emissions), will provide the EPA and other stakeholders with a better understanding of the impact of different emission source types on the performance of flares.

Second, we are finalizing as proposed adjustments to several of the existing reporting elements to align with proposed changes to the calculation methodology. For example, existing 40 CFR 98.236(n)(4) requires reporting of the total volume of gas routed to the flare. As described in section III.N.1. of this preamble, the final amendments add an option for reporters to determine volume of each stream routed to the flare. To align with this monitoring approach, 40 CFR 98.236(n)(11) in the final amendments adds a requirement to report the volumes for each of the individual streams if the reporter elects to determine the flow rate of the individual streams rather than the total. Similarly, existing 40 CFR 98.236(n)(7) and (8) require reporting of the CH_4 and CO_2 in the feed gas to the flare. To align with the final option that allows determination of gas composition at all of the source stream levels as an alternative to determination of the composition at the flare inlet, as discussed in section III.N.1. of this preamble, 40 CFR 98.236(n)(14) and (15) in the final amendments require reporting of the annual CH_4 and CO_2 mole fractions for each of the individual streams routed to the flare if the reporter elects to determine composition of those streams.

Further, the final 40 CFR 98.236(n)(7) requires reporters to indicate whether flow to the flare is measured at the inlet to the flare or determined for individual streams routed to the flare, and if it is measured at the inlet to the flare, then the reporter must indicate whether the volume was determined using a continuous flow measurement device or if it was determined using monitored parameters and engineering calculations. If the flow is determined for individual streams routed to the flare, the reporter must indicate, for each stream, whether the volume was determined using a continuous flow measurement device, using monitored parameters and engineering calculations, or other simulation or engineering calculation methods. Similarly, the final 40 CFR 98.236(n)(8) requires reporters to indicate whether gas composition was determined at the inlet to the flare using a continuous gas analyzer, sampling and analysis, or if composition was determined for the individual streams that are routed to the flare. If the composition is determined for individual streams routed to the flare, the reporter must indicate, for each stream, whether the composition was determined using a continuous gas analyzer, sampling and analysis, or other simulation or engineering calculation methods. The final requirements in these sections have been revised from proposal to align with the final revisions to the calculation methodology.

Third, we are finalizing requirements in 40 CFR 98.236(n)(12) (proposed 40 CFR 98.236(n)(13)) for destruction and combustion efficiencies. Proposed 40 CFR 98.236(n)(13) would require reporting of the combustion efficiency used to calculate emissions from each flare. As discussed in section III.N.1. of this preamble, the final amendments were revised from proposal to require use of both destruction efficiencies and combustion efficiencies to calculate flared emissions. Additionally, as discussed in section III.N.1. of this preamble, the final amendments include an option to use efficiencies higher than the defaults if the reporter implements an alternative test method that is approved as specified in NSPS OOOOb. To align with these revisions to the calculation methodology, 40 CFR 98.236(n)(13) in the final amendments requires reporting of the destruction efficiency used for each flare. Additionally, 40 CFR 98.236(n)(13) in the final amendments requires reporting, as proposed, of a flow-weighted destruction efficiency if the reporter calculates emissions for part of the year using one destruction efficiency and calculates emissions for the rest of the year using a different destruction efficiency. In a change from the proposal, the final amendments require reporting of flow-weighted average combustion efficiency fractions to three decimal places instead of one decimal place; the proposed requirement was incorrect because the efficiencies are to be reported as fractions (*i.e.,* consistent with the values used in equations W–19 and W–20), not percentages. These data will help with verification of the reported emissions.

We are finalizing the addition of several new reporting elements in 40 CFR 98.236(n)(13) to align with changes to the final flare efficiency options. If you comply with Tier 1 or Tier 2, new requirements to report the number of days in periods of 15 or more consecutive days when you did not conform with all cited provisions in 40 CFR 98.233(n)(1)(i) or (ii) are included in both final 40 CFR 98.236(n)(13)(i) for Tier 1 and in 40 CFR 98.236(n)(13)(ii) for Tier 2. These reporting requirements align with the requirements in the final Tier 1 and Tier 2 calculation methodologies to use the Tier 3 efficiencies for periods of monitoring parameter non-conformance that exceed 15 consecutive days. For facilities that report flares using a destruction efficiency of 95 percent (Tier 2), final 40 CFR 98.236(n)(13)(ii), as proposed, requires reporters to indicate whether the flare is subject to NSPS OOOOb or whether the reporter is electing to implement flare procedures that are specified in NSPS OOOOb. The final amendments also extend this reporting requirement to whether the reporter is subject to a state or Federal plan in 40 CFR part 62 implementing EG OOOOc or is electing to follow a state or Federal Plan in 40 CFR part 62 implementing EG OOOOc. Another new data element in final 40 CFR 98.236(n)(13) requires facilities with flares that are enclosed ground level flares or enclosed elevated flares that are not required to comply with NSPS OOOOb or state or Federal Plan in 40 CFR part 62 implementing EG OOOOc but are electing to comply with Tier 2 efficiencies to indicate if the most recent performance test was conducted using the method in 40 CFR 60.5413b(b) (*i.e.,* onsite testing), the method in 40 CFR 60.5413b(d) (*i.e.,* manufacturer testing), or the alternative method specified in 40 CFR 98.233(n)(1)(iv) (*i.e.,* OTM–52). Finally, new reporting elements are added in final 40 CFR 98.236(n)(13)(iii) that require reporters to indicate if they are using an efficiency for an alternative test method approved under 40 CFR 60.5412b(d) and if they are, to also report the approved destruction efficiency and the date when the reporter started to use the alternative test method. This information will help the EPA verify the reported data.

Fourth, existing 40 CFR 98.236(n)(12) requires reporting of whether a CEMS was used to measure CO_2 emissions from the flare. This reporting requirement is retained in 40 CFR 98.236(n)(20) as proposed, along with a requirement that the CO_2 mole fraction of the gas sent to the flare should not be reported when using CEMS because equation W–20 is not used to calculate CO_2 emissions when using a CEMS.

Fifth, one objective of the current flare reporting requirements is to obtain information on the total number of flares and their operating characteristics. We are finalizing as proposed the addition of a few new flare-specific reporting elements to help us better understand the state of flaring in the industry for carrying out provisions under the CAA and to improve data quality, 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) in 40 CFR 98.236(n)(4) 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) in 40 CFR 98.236(n)(5). These data will help the EPA assess the impact of design and operation on emissions and may be useful in analyses for potential future policy decisions related to flares under the CAA. To harmonize the final reporting requirements with the final requirement to either continuously monitor or periodically inspect for the presence of a pilot flame as discussed in section III.N.1. of this preamble, we are finalizing as proposed 40 CFR 98.236(n)(6) requiring that reporters indicate for each flare whether they continuously monitor for the presence of a pilot flame, conduct periodic visual inspections, or both. As proposed, if periodic visual inspections are conducted, 40 CFR 98.236(n)(6) also requires reporting of the count of inspections conducted during the year. Since the final rule requires a continuous pilot, we are not finalizing the proposed requirement to report whether the inspected flare has a continuous pilot or auto igniter. For a pilot flame that is monitored continuously, the final amendments as proposed also require reporting of the number of times the continuous monitoring devices were out of service or otherwise inoperable for a period of more than one week.

The EPA is not finalizing the proposed requirement for 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 to report 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. At proposal, we indicated that this proposed data element would provide information on what source types are generating significant emissions from miscellaneous flared sources. However, after consideration of public comments indicating that the fraction would be difficult to determine, we have decided not to take final action on this requirement at this time.

Finally, because the proposed calculation methodologies for flares would have required measurement of flow and composition rather than use of source-specific calculation methodologies, the EPA also proposed that source types that are flared for the entire year would not be required to report the activity data associated with those source-specific calculation methodologies. Instead, those sources would have only been required to report identifying information about the unit and indicate that emissions were routed to a flare the entire year under the individual source type, and all other activity data related to the flares would have been reported under 40 CFR 98.236(n). Under the final amendments, if the flow of the gas routed to a flare is not measured according to 40 CFR 98.233(n)(3)(i) and (n)(3)(ii)(A) and/or the composition of the gas routed to a flare is not measured according to 40 CFR 98.233(n)(4)(i) and (ii), then the reporter must determine the flow and composition of the gas using the calculation methods for that source type, per final 40 CFR 98.233(n)(3)(ii)(B) and 98.233(n)(4)(iii). Because the final amendments provide multiple methods for calculating the flow and composition of gas streams routed to flares, the EPA is not finalizing the consolidation of all the flare-related activity data under 40 CFR 98.236(n), as was proposed. Instead, for the disaggregated sources listed in 40 CFR 98.233(n)(3)(ii)(B)(*1*) through (7), the EPA is finalizing reporting requirements within the section for each source type that is routed to a flare. These source-specific reporting requirements apply in addition to the information required to be reported under 40 CFR 98.236(n) for the flare. Specifically, for these source types with gas routed to a flare, reporters will continue to report the required identifying information (*e.g.,* unit ID, well ID, well-pad ID) and then indicate at the specified reporting level (*e.g.,* by well or individual source type, by well-pad site or gathering and boosting site) whether the gas was routed to the flare for part of the year or the entire year and provide the flare stack identifier or name as well as the unique ID for the stream routed to the flare.

Reporters will also report whether the gas flow and composition were determined through measurement or the source-specific methodologies for sources listed in 40 CFR 98.233(n)(3)(ii)(B)(*1*) through (*7*). In cases where the reporter is using source type-specific calculation methods, it is essential that certain activity data be reported for the source type for accurate verification of reported emissions data and also accurate allocation of disaggregated emissions data, if applicable. Therefore, if a source-specific methodology is used, reporters will be required to report the same activity data for the source type as they would if the gas were vented directly to the atmosphere. For example, if an acid gas removal vent is routed to a flare and the flow and composition of the gas routed to the flare is determined using Calculation Method 4, the reporter will be required to provide the activity data associated with Calculation Method 4 under 40 CFR 98.236(d)(2)(iv). Other examples include completions and workovers with hydraulic fracturing, for which the reporter will be required to indicate the calculation method used and data specific to equation W–10A and W–10B; completions and workovers without hydraulic fracturing, for which the reporter will be required to provide the inputs to equations W–13A and W–13B; and associated gas flaring, for which the reporter will be required to provide the inputs to equation W–18. These data are essential for the verification of flared emissions and the identification of the flare to which the emission sources are routed.

For sources that are routed to flares other than those listed in 40 CFR 98.233(n)(3)(ii)(B)(*1*) through (*7*), flow to the flares is required to be determined using engineering calculations based on process knowledge, company records, and best available data in accordance with 40 CFR 98.233(n)(3)(ii)(B)(*8*), and no additional reporting requirements within the section for each source type are being finalized.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to the reporting requirements for flare stacks.

Comment: Commenters opposed the proposal of the requirement in proposed 40 CFR 98.236(n)(10) to report the estimated fraction of total volume flared that was received from another facility solely for flaring. Commenters indicated that this information would be difficult to determine and would not provide meaningful information. The commenters stated that the EPA should require reporting of the emissions from a flare stack without considering whether the gas was received from another facility.

Response: After review of these comments, we are not taking final action at this time on the proposed reporting requirement. In the preamble to the proposed rule, we indicated that this proposed data element would help the EPA understand what source types are generating the large amounts of flared gas reported under miscellaneous flared sources, and that if the source type also is not currently subject to source-specific reporting of vented emissions, then a potentially large quantity of vented emissions might go unreported. However, the proposed data element would have only indicated whether the gas was received from a different facility to be flared; it would not have told us what emission source generated the gas. In addition, in this final rule, we are finalizing the addition of numerous new emission sources under subpart W, so the likelihood that another potentially large quantity of vented emissions might go unreported has decreased. The EPA not taking final action on this reporting requirement at this time does not affect the general requirements to calculate and report total emissions from each flare stack.

3. Definition of Flare Stack Emissions

The term ''flare stack emissions'' in 40 CFR 98.238 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.'' As noted in the 2023 Subpart W Proposal, the current definition does not clearly convey the EPA's intent that the CO_2 that enters a flare should be reported as flare stack emissions and it implies N_2O emissions only result from partial combustion of hydrocarbons in the gas routed to the flare, which is not the case. Consistent with section II.D. of this preamble, in order 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 finalizing as proposed the revision of the definition of the term ''flare stack emissions'' in 40 CFR 98.238 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. The EPA received only supportive comments regarding the revisions to the definition of ''flare stack emissions.'' See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

O. 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. We are finalizing several amendments to subpart W related to compressors as proposed, finalizing some amendments with revisions from proposal, and not finalizing other proposed amendments.

1. Mode-Source Combination Measurement Requirements

a. Summary of Final Amendments

The EPA is finalizing 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 existing 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. Therefore, we are finalizing as proposed the revised definition of compressor mode in 40 CFR 98.238 that includes standby-pressurized-mode as a defined mode for centrifugal compressors. We are also finalizing as proposed the requirement to measure volumetric emissions from the wet seal oil degassing vent or dry seal vent, as applicable (see discussion in the following paragraph) and the volumetric emissions from blowdown valve leakage through the blowdown vent when the compressor is found in standby-pressurized-mode (40 CFR 98.233(o)(1)(i)(C)), consistent with section II.A. of this preamble.

Second, dry seals on centrifugal compressors were not included in the existing 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 when the dry seal compressor is well-maintained and operating normally, dry seals still contribute to centrifugal compressor emissions, especially if they are poorly maintained or there are unforeseen upset conditions. Therefore, to better characterize the emissions from dry seal centrifugal compressors, we are finalizing the revised definition of compressor source in 40 CFR 98.238 to include dry seal vents as one of the defined compressor sources for centrifugal compressors. We are also finalizing as proposed the requirement to measure volumetric emissions from the dry seal vents in both operating-mode and in standby-pressurized-mode (40 CFR 98.233(o)(2)(iii)), consistent with section II.B. of this preamble. Under the final provisions, the measurement methods for the dry seal vents are similar to those provided for reciprocating compressor rod packing emissions and include the use of temporary or permanent flow meters, calibrated bags, and high volume samplers. We are finalizing as proposed that screening methods may also be used to determine if a quantitative measurement is required. We are finalizing as proposed the specification that acoustical screening or measurement methods are not applicable to screening dry seal vents because emissions from dry seal vents are not a result of through-valve leakage. As proposed, certain requirements in 40 CFR 98.236(o) are now applicable to the dry seal compressor source under the final rule, including new reporting requirements in 40 CFR 98.236(o)(1)(x) to report the number of dry seals on centrifugal compressors and in 40 CFR 98.236(o)(2)(B) to report dry seals as one of the centrifugal compressor sources.

Third, we are finalizing as proposed the revision to 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.[65] The inclusion of this compressor mode-source combination more accurately reflects compressor emissions, consistent with section II.A. of this preamble.

Fourth, we are finalizing as proposed the elimination of the requirement in 40 CFR 98.233(o) to conduct a measurement in not-operating-depressurized-mode at least once every three years, consistent with section II.C. of this preamble. We originally included the requirement for compressors that were not measured in not-operating-depressurized-mode during the ''as found'' measurements for three consecutive years 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. Therefore, facilities are able to obtain a sufficient number of measurements in not-operating-depressurized-mode to calculate an accurate mode-source specific emission factor without the additional requirement. As such, the extra measurements are no longer necessary, and the final amendments in this rule make the annual measurements true ''as found'' measurements. We are also finalizing as proposed the removal of the reporting requirement in 40 CFR 98.236(o) to indicate if the compressor had a scheduled depressurized shutdown during the reporting year 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.

Fifth, we are finalizing one additional change to the proposed 40 CFR 98.233(o)(2)(iii) to clarify the specific location where the dry seal measurement should be conducted. Language has been added to note that

[65] 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–2023–0234.

the measurement should be made on the compressor side dry seal. This change was made to prevent measurements on the outboard side dry seal, because process gas emissions from the dry seal on the outboard side are very low.[66]

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to mode-source combination measurement requirements.

Comment: All commenters supported the proposed changes to the mode-source combination measurement requirements. In addition, one commenter suggested a change to 40 CFR 98.233(o)(2)(iii) to clarify that the dry seal measurement should be conducted on the compressor side.

Response: We agree with the commenter that clarity is needed to describe where the dry seal measurement should be conducted. Thus, in the final rule, we are adding appropriate language to 40 CFR 98.233(o)(2)(iii) to clarify that dry seal measurements should be conducted on the compressor side dry seal. All other changes to mode-source combination measurement requirements are being finalized as proposed.

2. Measurement Methods

a. Summary of Final Amendments

The EPA is finalizing several amendments related to the measurement method requirements to improve the quality of data collected for compressors. First, we are finalizing as proposed the revisions to the allowable methods for measuring wet seal oil degassing vents. Previously, the only method provided in 40 CFR 98.233(o)(2)(ii) for measuring volumetric flow from wet seal oil degassing vents was the use of a temporary or permanent flow meter. We are finalizing the revision to 40 CFR 98.233(o)(2)(ii) allowing the use of calibrated bags and high volume samplers. As proposed, under the final provisions we specify that the use of screening methods for wet seal oil degassing vent measurement is not allowed, because wet seal oil degassing vents are expected to always have some natural gas flow. These revisions to 40 CFR 98.233(o)(2)(ii) provide improved clarity of the wet seal oil degassing provisions and allow an additional measurement method that was determined to be accurate for this source, consistent with section II.B. of this preamble.

Second, we are finalizing, with two revisions from proposal, the removal of acoustic leak detection from the screening and measurement methods allowed for manifolded groups of compressor sources. Acoustic leak detection is applicable only for through-valve leakage. Therefore, the acoustic method for screening or measurement can be applied only to individual compressor sources associated with through-valve leakage (*i.e.,* blowdown valve leakage or isolation valve leakage), but it cannot be used for screening emissions from or measurement of emissions from a vent that contains a group of manifolded compressor sources downstream from the individual valves or other sources that may be manifolded together. The previous inadvertent inclusion of this method for manifolded compressor sources was in error and we are finalizing its removal 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.B. of this preamble.

The final provisions include minor changes from the proposal to add two new paragraphs at 40 CFR 98.233(o)(4)(ii)(F) and 40 CFR 98.233(p)(4)(ii)(F) to allow the use of acoustic leak detection as a tool for manifolded compressor sources only after screening (to determine that there is a leak) but prior to measurement (to quantify the leak). This revision does not negate the fact that acoustic leak detection should only be used on through-valve leakage for screening and measurement. This revision simply allows the use of acoustic leak detection, according to 40 CFR 98.234(a)(5), as a tool to identify one leaking compressor valve among a group of multiple potentially leaking compressor valves. A screening method from 40 CFR 98.234(a)(1) through (3) will still be required to identify that a leak is occurring in the manifolded group of compressors, and a measurement method from 40 CFR 98.233(o)(4)(ii)(A) through (D) or 40 CFR 98.233(p)(4)(ii)(A) through (D) will still be required to quantify the leak, once the leaking compressor valve is identified. Acoustic leak detection will only be allowed to determine which compressor included in the manifolded group is leaking, in order to make proper measurement of the leak easier to perform. We included these changes after consideration of public comment.

Third, we are finalizing as proposed 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.D. of this preamble. These final 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) 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 because rod packing is not through-valve leakage.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments related to measurement methods.

Comment: One commenter suggested an edit to allow acoustic leak detection in limited circumstances. The commenter asked that the EPA selectively retain the use of acoustic devices for manifolded compressors to identify the source of the leak, but not to quantify emissions. The use of acoustic leak detection would help determine which compressor valve should be measured downstream of the manifold, using one of the other methods specified in 40 CFR 98.233(o)(4)(ii)(A) through (D) or 40 CFR 98.233(p)(4)(ii)(A) through (D). Specifically, the commenter asked that if one of the screening methods specified in 40 CFR 98.234(a)(1) through (3) identifies a leak in a manifolded group of compressor sources, that the reporter be allowed to use acoustic leak detection, according to 40 CFR 98.234(a)(5), to identify which compressor valve is leaking.

Response: The EPA reviewed the comment and determined that a limited retainment of the use of acoustic leak detection, to identify which compressor valve in a manifolded group of

[66] Reducing Emissions from Compressor Seals; Lessons Learned from Natural Gas STAR. Available at *https://www.epa.gov/sites/default/files/2017-09/documents/reducingemissionsfromcompressorseals.pdf.* Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

compressor sources is leaking, is appropriate. In this case, acoustic leak detection is not being relied upon to identify whether there is a leak in the first place. Instead, this revision allows the use of acoustic leak detection as a tool to identify the source of a leak from a group of manifolded compressors. However, acoustic leak detection will not be allowed to be used as a screening or measurement method to identify or quantify emissions from a manifolded group of compressors. This revision has been included in the final provision.

Comment: One commenter asked that the rule allow flexibility to integrate advanced technologies that become available, such as the option of using an OGI emissions quantification system, which the commenter noted as a technology still under development, as an accepted technology for methane emissions quantification when the performance of that technology is confirmed.

Response: Without specific details that are necessary to evaluate and incorporate such methodologies, such as the performance, accuracy or precision of the aforementioned technology, and how the aforementioned technology can be applied specifically to compressor emission sources, the EPA is not able to fully evaluate for potential incorporation in this rulemaking quantitative OGI or other technologies that are currently still under development. Therefore, at this time such technologies are not included in the final provisions.

3. Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting

a. Summary of Final Amendments

As noted in the introduction to section II. of this preamble, the EPA recently finalized NSPS OOOOb and EG OOOOc for certain oil and natural gas sources. The final standards in NSPS OOOOb and the final presumptive standards in EG OOOOc include emission limits for reciprocating compressors, centrifugal compressors with wet seals, and centrifugal compressors with dry seals that apply when the compressor is in operating-mode or standby-pressurized-mode. The final standards require owners or operators to conduct volumetric emissions measurements from each reciprocating compressor rod packing or centrifugal compressor wet or dry seal on or before 8,760 hours of operation from startup or from the previous measurement. Similar to the 2016 amendments to subpart W specific to equipment leak surveys (81 FR 4987, January 29, 2016), the EPA is finalizing, with a revision from proposal, the calculation methodologies in 40 CFR 98.233(o)(10) and 40 CFR 98.233(p)(10) for compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities in subpart W so that data derived from centrifugal compressor or reciprocating compressor monitoring conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 will be required to be used to calculate emissions for subpart W reporting, consistent with section II.B. of this preamble.

For compressors at onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting facilities not subject to either NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62, we are finalizing, with a revision from proposal, the calculation methodologies in 40 CFR 98.233(o)(10) and 40 CFR 98.233(p)(10) such that reporters have the option to calculate emissions for subpart W reporting using the same provisions for ''as found'' measurements as other industry segments under 40 CFR 98.233(o)(1)(i) and 40 CFR 98.233(p)(1)(i), using methods specified in 40 CFR 98.233(o)(2) through (5) or 40 CFR 98.233(p)(2) through (5), as applicable, based on the compressor mode (as defined in 40 CFR 98.238) in which the compressor was found at the time of measurement, and calculating emissions as specified in 40 CFR 98.233(o)(6) through (9) or 40 CFR 98.233(p)(6) through (9), as applicable. These revisions will allow owners and operators of onshore petroleum and natural gas production or onshore petroleum and natural gas gathering and boosting facilities to use facility measurement data in their emission calculations for compressors, consistent with section II.B. of this preamble.

The EPA is finalizing, with a revision from proposal, requirements under subpart W in 40 CFR 98.233(o)(10) and 40 CFR 98.233(p)(10) for compressors subject to the final standards in NSPS OOOOb or standards in an applicable approved state plan or applicable Federal plan codified in 40 CFR part 62, which are necessary due to the different scope and purpose of the GHGRP subpart W provisions compared to the final standards in NSPS OOOOb and the finalized presumptive standards in EG OOOOc. The EPA is finalizing as proposed that reporters conducting measurements of compressors under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 must conduct measurements of all other compressor sources required to be measured by subpart W (based on the compressor mode (as defined in 40 CFR 98.238) in which the compressor was found at the time of measurement) specified in 40 CFR 98.233(o)(1) or 40 CFR 98.233(p)(1), using methods specified in 40 CFR 98.233(o)(2) through (5) or 40 CFR 98.233(p)(2) through (5), as applicable, and calculating emissions as specified in 40 CFR 98.233(o)(6) through (9) or 40 CFR 98.233(p)(6) through (9), as applicable.

Because the time between measurements under the final standards in NSPS OOOOb and the final presumptive standards in EG OOOOc may not result in measurements being taken every reporting year, the EPA is finalizing as proposed the requirement to use equation W–22 or equation W–27, as applicable, to calculate emissions from all mode-source combinations for any reporting year in which measurements are not required.

As discussed at proposal, the final standards in NSPS OOOOb and the finalized presumptive standards in EG OOOOc only require measurements to be taken in operating-mode or standby-pressurized-mode. If no compressor sources are measured in not-operating-depressurized-mode, reporters would not have data to develop reporter emission factors for that mode-source combination using equation W–23 and equation W–28. The EPA proposed in 40 CFR 98.233(o)(10)(i)(B) and 40 CFR 98.233(p)(10)(i)(B) that reporters with compressors subject to NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 would be required to conduct additional measurements of compressors in not-operating-depressurized-mode such that they can develop an annual reporter emission factor for isolation valve leakage in not-operating-depressurized-mode.

The main revision to the proposed amendments for compressors in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments is the removal of the aforementioned requirement to conduct measurements of compressors in not-operating-depressurized-mode on a regular basis. We received many comments suggesting the requirement was overly burdensome and difficult to implement. After consideration of public comment, the EPA is not finalizing the requirement to conduct additional measurements of compressors in not-operating-depressurized-mode. Instead, the final amendments only require measurements in not-operating-depressurized mode if the compressor is in not-operating-depressurized mode at the time of measurement, making the annual measurements of compressors in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments true ''as found'' measurements.

For facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments that do not conduct measurements, we are finalizing 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.B. 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. Therefore, we are finalizing as proposed 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–25A should be the number of centrifugal compressors with atmospheric (*i.e.,* uncontrolled) wet seal oil degassing vents. Similarly, we are finalizing 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. We are also finalizing as proposed additional 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 additional requirements to report the total number of reciprocating compressors at the facility to 40 CFR 98.236(p)(5). These additional data 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.C. of this preamble.

In addition, consistent with section II.B. of this preamble, and after consideration of public comment, the EPA is finalizing the proposed CH_4 and CO_2 population emission factors in equation W–29E, while also allowing for adjustment of total operating time and mole fraction of CH_4 and CO_2. As discussed at proposal, the reciprocating compressor population emission factor for CH_4 is based on the average population emission rate measured by Zimmerle *et al.* (2019), with a CO_2 population emission factor derived by applying the ratio of the current CO_2 emission factor to the current CH_4 emission factor to the CH_4 emission factor obtained from Zimmerle *et al.* (2019).

After consideration of public comments and review of the proposal, the EPA is finalizing a few additional changes related to reciprocating compressors. First, a new equation W–29E has been added to subpart W to calculate emissions from each reciprocating compressor at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which 40 CFR 98.233(p)(10)(i) does not apply and for which the facility does not elect to conduct the volumetric measurements specified in 40 CFR 98.233(p)(1), using the final emission factors and allowing for adjustment of total operating time and mole fraction of CH_4 and CO_2. Second, equation W–29D has been revised to calculate total emissions from all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which 40 CFR 98.233(p)(10)(i) does not apply and for which the facility does not elect to conduct the volumetric measurements specified in 40 CFR 98.233(p)(1), as a sum of all reciprocating compressor emissions calculated using equation W–29E.

These changes were made in response to a public comment asking to allow adjustment of total operating time and mole fraction of CH_4 and CO_2 in the calculation of emissions from reciprocating compressors. As proposed, equation W–29D only allowed for the use of the count of total reciprocating compressors used at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility multiplied by the emission factor. Adjustment for total compressor operating time and specific mole fractions of CH_4 and CO_2 is made on a compressor-specific basis. Therefore, in the final rule, equation W–29E calculates CH_4 and CO_2 emissions from each reciprocating compressor at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility (allowing for adjustment to reflect actual operating time and CH_4 and CO_2 mole fractions associated with each compressor) and equation W–29D calculates total CH_4 and CO_2 emissions from all reciprocating compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using individual compressor emissions determined for each reciprocating compressor according to equation W–29E. These revisions allow for the incorporation of unit-specific data and are expected to increase the accuracy of the calculated compressor emissions, consistent with section II.B. of this preamble.

Additionally, corresponding changes were made for centrifugal compressors. Even though this change was not requested by commenters, the change was made for equitable treatment of both types of compressors. First, a new equation W–25B has been added to subpart W to calculate emissions from each centrifugal compressor at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which 40 CFR 98.233(o)(10)(i) does not apply and for which the facility does not elect to conduct the volumetric measurements specified in 40 CFR 98.233(o)(1), using the emission factors and allowing for adjustment of total operating time and mole fractions of CH_4 and CO_2. Second, equation W–25A has been revised (and renamed from equation W–25) to calculate total emissions from all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which 40 CFR 98.233(o)(10)(i) and (ii) do not apply, as a sum of all centrifugal compressor emissions calculated using equation W–25B.

Paragraphs 40 CFR 98.233(o)(10)(iii) and 98.233(p)(10)(iii) were revised and new paragraphs 40 CFR 98.233(o)(10)(iv) and 98.233(p)(10)(iv) were added to incorporate these revisions.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments related to Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting measurement methods.

Comment: Multiple commenters disagreed with the proposed amendments to 40 CFR 98.233(o)(10)(i)(B) and 40 CFR 98.233(p)(10)(i)(B) to require reporters with compressors subject to NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 to conduct additional measurements of compressors in not-operating-depressurized-mode, such that they can develop an annual reporter emission factor for isolation valve leakage in not-operating-depressurized-mode. The proposed amendments the commenters disagreed with would require reporters to measure emissions in not-operating-depressurized mode from isolation valve leakage for at least one-third of the subject compressors during any 3 consecutive calendar year period.

According to one commenter, compressors used in production and gathering and boosting are rarely unpressurized while remaining at a specific location. When the compressors are no longer needed at a specific site, the commenter stated that the compressors are shut down and moved to another location. Another commenter noted that gathering and boosting facilities typically have very few compressors per site and they are generally running continuously. Not-operating-depressurized mode is an uncommon mode, so requiring a measurement in that mode is unnecessary and could lead to higher emissions, especially if a compressor is shut down to meet this requirement and there is an unexpected critical need for the compressor to be operating.

Response: After consideration of public comment, the EPA is not finalizing the proposed changes to require compressor measurements in not-operating-depressurized mode such that at the end of each calendar year, reporters have taken measurements in not-operating-depressurized-mode over the last 3 consecutive calendar years for at least one-third of the compressors at the facility. Preemptively requiring a measurement in not-operating-depressurized mode, especially if compressors in the industry segments are rarely in this mode, appears to be an unnecessary requirement. The main reason to require this measurement is to ensure that reporters have a way to estimate emissions in not-operating-depressurized mode when measurements are not available (*i.e.,* the reporter can use measurements from other years to determine an average emission factor). If compressors in these industry segments are rarely in this mode, an average emission factor is not needed. Reporters who elect to conduct the volumetric emission measurements specified in 40 CFR 98.233(o)(10)(ii) or 40 CFR 98.233(p)(10)(ii) will conduct as-found compressor measurements. Measurements in not-operating-depressurized mode will only be required if the compressor is in not-operating-depressurized mode at the time of measurements. If the dataset from these reporters shows a high instance of not-operating-depressurized mode measurements from compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities than indicated by the commenters, the EPA may reconsider this requirement in future rulemakings.

Comment: One commenter noted that equation W–29D in 40 CFR 98.233(p) does not allow for adjustment based on gas composition. Due to the wide variety in the composition of gas produced from different basins and formations across the U.S., the commenter asked that the emission factor method allow for adjustment based on CO_2 and CH_4 composition reflective of each compressor. The commenter noted that composition adjustment of Emission Factor-based calculations is allowed under subpart W for pneumatic devices, pneumatic pumps, and equipment leaks.

The commenter also noted that equation W–29D in 40 CFR 98.233(p) does not allow for adjustment based on the number of hours a compressor operates during a calendar year. The commenter noted that compressors can be moved on and off location during a year. The commenter stated that assuming the compressor operated for the entire year could result in inaccurate data. The commenter noted that adjustment of operating hours is allowed under subpart W for pneumatic devices, pneumatic pumps, and equipment leaks and improves the accuracy of the emissions estimated.

Response: The EPA reviewed the comments and agreed that changes to allow adjustment of operating hours and pollutant mole fractions when applying the CH_4 and CO_2 emission factors to compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities were warranted. These types of adjustments are already allowed for pneumatic devices, pneumatic pumps, and equipment leaks. Allowing this type of flexibility improves the emissions calculation methodology for compressors, consistent with section II.B. of this preamble, and also improves the accuracy of the emissions estimated from compressors at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

4. Compressors Routed to Controls

The EPA is finalizing several revisions related to centrifugal and reciprocating compressors routed to controls as described in this section. The EPA received only minor comments regarding centrifugal and reciprocating compressors routed to controls. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

Centrifugal and reciprocating compressors are the only sources for which capture for fuel use and thermal oxidizers currently are specifically listed as dispositions for emissions that would otherwise be vented (see 40 CFR 98.233(o) and (p) introductory text). 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. Consistent with section II.D. of this preamble, in order to clarify and emphasize that the EPA's intent is generally to treat emissions routed to flares and combustion devices other than flares consistently, we are finalizing as proposed removal of 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). Also, we are finalizing as proposed 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 final definition of ''routed to combustion'' applies for all subpart W emission sources for which that term appears (*e.g.,* natural gas driven pneumatic pumps).

5. Reporting of Compressor Activity Data

The EPA is finalizing as proposed several amendments to remove redundancy, consistent with section II.D. of this preamble. The EPA received only supportive comments regarding revisions to remove reporting redundancy for centrifugal and reciprocating compressors. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

We are finalizing the removal of 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, current 40 CFR 98.236(o)(1)(vi) and 40 CFR 98.236(p)(1)(viii) require reporters to indicate which individual compressors are part of a manifolded group of compressor sources, and current 40 CFR 98.236(o)(1)(vii) through (ix) and 40 CFR 98.236(p)(1)(ix) through (xi) require reporters to indicate whether individual compressors have compressor sources routed to flares, vapor recovery, or combustion. However, current 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 finalizing the removal of the redundant reporting requirements in existing 40 CFR 98.236(o)(1)(vi) through (ix) and existing 40 CFR 98.236(p)(1)(viii) through (xi), consistent with section II.B. of this preamble.

P. Equipment Leak Surveys

Subpart W reporters are currently 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 currently 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 existing table W–1E to 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–2023–0234. 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 this final rule, consistent with the 2023 Subpart W Proposal, we are making several technical changes to the equipment leak survey provisions for the equipment leak emission source. The key changes included in this final rule are providing updated and new leaker emission factors, revising and providing new leaker calculation methodologies, and providing better alignment with the NSPS OOOOa and NSPS OOOOb as well as EG OOOOc survey requirements.

1. Revisions and Addition of Default Leaker Emission Factors

a. Summary of Final Amendments

We are finalizing as proposed to amend the leaker emission factors in existing table W–1E (final table W–2) to subpart W for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities to update the Method 21 emission factors as well as include separate emission factors for leakers detected with OGI, consistent with section II.B. of this preamble. We are finalizing as proposed to revise the emission factors using study data from Zimmerle *et al.* (2020) and Pacsi *et al.* (2019). The Zimmerle *et al.* (2020) study contains hundreds of quantified leaks detected using OGI. The Pacsi *et al.* (2019) study also contains hundreds of equipment leak measurements from sites that were screened using Method 21 with a leak definition of 10,000 ppm and 500 ppm as well as OGI. We are finalizing the use of these studies as the basis for the final 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.

Numerous equipment leak studies,[67] including Pacsi *et al.* (2019) have found that OGI detects fewer leaks that are on average larger in size than those detected by EPA 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. Using the Pacsi *et al.* (2019) study data, we estimate that the leaks detected by OGI are 1.63 times larger than leaks detected by Method 21 at a

[67] 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 ID. 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–2023–0234.

leak definition of 10,000 ppm and 2.81 times larger than leaks detected by Method 21 at a leak definition of 500 ppm. As noted, the Pacsi *et al.* (2019) study provides data on leaks detected by Method 21 at a leak definition of 10,000 ppm and 500 ppm as well as OGI data, however, the sample size of leaks screened in the Pacsi *et al.* (2019) study with Method 21 is smaller than those screened with OGI, particularly when combining the OGI data from Pacsi *et al.* (2019) with the Zimmerle et al. (2020) data. The combined OGI dataset from Pacsi *et al.* (2019) and Zimmerle et al. (2020) contains more than 700 measurements from leaks detected with OGI. Emission factors using these data are derived for each combination of well site type (*e.g.,* gas or oil) and component type (*e.g.,* valve). The more than 700 measurements in the combined OGI dataset results in an average of 44 measurements for each combination of well site type (*e.g.,* gas or oil) and component type (*e.g.,* valve). In contrast, the Pacsi *et al.* study has nearly 300 measurements for leaks detected using Method 21 at a leak definition of 500 ppm and 140 measurements for leaks detected using Method 21 at a leak definition of 10,000 ppm, which results in averages of 21 measurements and 10 measurements for each combination of site type and component type, respectively.

For OGI, we are finalizing leaker emission factors that were developed using the combined data from Pacsi *et al.* (2019) and Zimmerle *et al.* (2020) by site type (*i.e.,* gas or oil). Equipment leaks are inherently variable; therefore, sample size is important when seeking to derive representative equipment leak emission factors. Therefore, in this final rule, we used the OGI data and the ratio between OGI and the Method 21 at a leak definition of 10,000 ppm and a leak definition of 500 ppm (*i.e.,* 1.63 and 2.81, respectively) measurements to derive the final emission factors for Method 21 at both leak definitions. The precise derivation of the final 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–2023–0234.

At onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, very few facilities report using infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys for the purposes of subpart W and there are no data available to develop leaker emission factors specific to these methods. Based on our understanding and our review of comments received on the 2023 Subpart W Proposal relative to the use of these alternative methods, we expect that their leak detection thresholds will be most similar to OGI, so that the average emissions per leak identified by these alternative methods will be similar to the emissions estimated using the final OGI leaker factors. Therefore, we are finalizing as proposed that, if other leak survey methods including illuminated laser beam or acoustic leak devices are used to conduct leak surveys, the final OGI leaker emission factors in final table W–2 to subpart W must 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, we note that subpart W currently specifies that all components should be considered to be in gas service consistent with the language in 40 CFR 98.233(q)(2)(iv); thus, under the final rule the gas service factors from final table W–2 should be applied to the count of equipment leak components consistent with the leak detection method used.

For onshore petroleum and natural gas production facilities, we are finalizing as proposed 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 (rather than the component-level service 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 final table W–2 to subpart W. After consideration of comments received on the proposed rule as discussed further in section III.P.1.b. of this preamble, we are also adding clarifying edits in this final rule to the footnotes of final table W–2. One of these edits removes footnote 1, which included a specification to use the gas service emission factors for multi-phase flow. This footnote 1 no longer applies. Consistent with the derivation of the default leaker emission factors, the default leaker emission factors must be applied by site type for onshore petroleum and natural gas production facilities, while onshore petroleum and natural gas gathering and boosting sites must use the gas service default leaker emission factors. The edits also clarify that the default leaker emission factors for the open-ended line (OEL) component type includes the blowdown valve and isolation valve leaks when using the population count emission factor approach specified in 40 CFR 98.233(o)(10)(iv) or (p)(10)(iv).

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 in terms of emission rate than EPA Method 21 (*i.e.,* each screening method finds a different, but overlapping, subset of the existing leaks). 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. We are finalizing as proposed the application of the ratio between OGI data and Method 21 at a leak definition of 10,000 ppm identified from the Pacsi *et al.* (2019) study data in the onshore production and gathering and boosting industry segments, a value of 1.63, to the leaker emission factors for the other subpart W industry segments as a means to estimate and finalize a separate OGI emission factor set. Analogous to the changes in final table W–2 to subpart W 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 final emission factor sets specific to OGI, infrared laser beam illuminated instrument, or acoustic leak detection device screening methods. The final emission factor sets are included in tables W–4 and W–6 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. A detailed description of the final emission factors is provided in the subpart W TSD, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. After consideration of comments, we are finalizing updated provisions to those proposed to provide that facilities reporting to the Onshore Natural Gas Transmission Compression or Underground Natural Gas Storage industry segments may use the concentration of CH_4 or CO_2 in the THC of the feed natural gas in lieu of the default concentrations provided in equation W–30 when quantifying equipment leak emissions using Calculation Method 1. The use of facility-specific composition data for the concentration of CH_4 or CO_2 in the THC feed of natural gas instead of using default values is expected to increase the accuracy of the emission estimates.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to the equipment leak survey default leaker emission factors.

Comment: Commenters noted that there were inconsistencies with the preamble to the 2023 Subpart W Proposal as well as proposed 40 CFR 98.233(q)(2)(iii) and (iv) and the footnote 1 to table W–2 to subpart W, which says, ''For multi-phase flow that includes gas, use the gas service emission factors.'' In the preamble to the 2023 Subpart W Proposal and in the proposed regulatory text, it says that emission factors should be applied by well site type for production facilities, where components at gas wells are considered to be in gas service and components at oil wells are considered to be in oil service. The proposed rule also provided that components at gathering and boosting sites should be considered to be in gas service. Further, commenters requested that the EPA clarify in footnote 2 to table W–2 that if an entity elects to use as-found measurements to estimate emissions from isolation valve and blowdown valve leakage, that leaks detected from these sources should be calculated pursuant to paragraph (p) or (o) rather than paragraph (q). Finally, commenters requested that the EPA clarify in footnote 2 to table W–2 how dry seal vents are intended to be reported when a gathering and boosting or processing site elects to use population emission factors for compressor venting.

Response: We agree with commenters that our intent, which is consistent with the derivation of the default leaker emission factors, is for production facilities to apply component-level emission factors based on the well site type and for components at gathering and boosting facilities to use the gas service default leaker emission factors. The reference to footnote 1 in the context of default leaker factors in final table W–2 to subpart W has been removed. We also agree with the commenters that clarification is needed in footnote 2 and have edited the footnote in the final rule to state that the OEL component type includes the blowdown valve and isolation valve leaks when using the population count emission factor approach specified in 40 CFR 98.233(o)(10)(iv) or (p)(10)(iv). Finally, in response to the request for clarification regarding dry seals, we note that there is no emission factor for dry seals in the existing rule, which is unchanged by this final rulemaking, and thus emissions associated with dry seals are not required to be reported.

Comment: Commenters requested that the EPA allow the use of annual average GHG mole fraction GHGi in equations W–30 and W–32A as allowed in equation W–1A for natural gas pneumatic devices. Commenters explained that this would better align equipment leak calculations with other calculations of subpart W and be consistent with the initiative of capturing empirical data.

Response: We agree with the commenter's suggestion to allow for the use of the actual concentration of CH_4 or CO_2 in the calculation of equipment leak emissions in 40 CFR 98.233(q) and (r) as we expect that when utilized the accuracy of the resulting emissions will increase. Therefore, we are finalizing amendments to the variable for the concentration of greenhouse gases, GHGi, in the definition of the variables for equations W–30 and W–32A to provide the option of using the existing default concentrations or the actual concentration of methane or carbon dioxide in the THC of the feed natural gas.

Comment: Several commenters opposed the separate OGI default leaker emission factors and noted that the derived emission factors are much higher for this leak survey method than for EPA Method 21. Other commenters expressed support for the separate OGI default leaker emission factors and stated that they believe the resulting emissions estimates will be more accurate.

Commenters opposing the separate OGI default leaker emission factors asserted that their inclusion disincentivizes the use of OGI. Commenters note that OGI was determined to be the best system for emission reductions (BSER) in the NSPS OOOOb and EG OOOOc rules, yet the proposed default leaker emission factors would penalize its use for emissions reporting. Commenters note that there were other sources of equipment leak data that could be considered when developing leaker emission factors including annual leak reports from the state of Colorado or the Environmental Partnership. Some commenters noted that the Pacsi *et al.* (2019) study was limited to four geographical regions, a single OGI camera make and model, and did not consider operator training. Another commenter stated that the Pacsi *et al.* (2019) study concluded, ''The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22 percent to 36 percent for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field surveys conducted more than 20 years ago to develop the current EPA factors.'' Some commenters stated that the EPA has selectively updated certain emission factors to inflate emissions in response to the Inflation Reduction Act and fiscal implications for oil and gas companies. Commenters recommended that the EPA maintain the OGI and Method 21 with a leak definition of 10,000 ppm default leaker emission factor set currently in the rule.

Commenters also opposed the use of the ''OGI enhancement factor,'' which was a ratio of the average leak rate size surveyed using OGI to EPA Method 21 to provide the updated Method 21 default leaker emission factors for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments.

Response: The proposed default leaker emission factors for the onshore natural gas production and onshore gathering and boosting facilities are based on the combination of data from publicly available and peer reviewed studies including the Pacsi *et al.* (2019) and Zimmerle *et al.* (2020) studies. The combined OGI dataset from Pacsi *et al.* (2019) and Zimmerle *et al.* (2020) contains more than 700 measurements from leaks detected with OGI. We derived OGI emission factors by site type (*i.e.,* gas or oil) directly from the combination of these data. The Pacsi *et al.* (2019) dataset includes equipment leaks surveyed with Method 21 at both leak definitions, but the sample sizes are smaller. Thus, we derived the ratio between OGI and the Method 21 at a leak definition of 10,000 ppm and a leak definition of 500 ppm (*i.e.,* 1.63 and 2.81, respectively) and applied the ratio to the OGI emission factors to derive the proposed emission factors for Method 21 at both leak definitions. The derivation of the separate emission factor sets seeks to utilize the most robust dataset of publicly available data to develop these separate leaker emission factors, consistent with findings in multiple studies that the average size of the leaks detected by OGI are larger than those detected by EPA Method 21. This approach is not intended to disincentivize any survey method and, furthermore as discussed below, our expectation is that the approach finalized in this rulemaking will yield similar equipment leak emission estimates regardless of the selected method. We maintain that the separate OGI emission factors are appropriate, accurate, and based on the best available data and we are finalizing them, as proposed.

Commenters mentioned that thousands of equipment leaks were reported to the state of Colorado. We have reviewed the data from the state of Colorado that are publicly available, and agree that many more leaks were reported statewide than are detected/measured in the Pacsi *et al.* (2019) and Zimmerle *et al.* (2020) studies. Similarly, we have reviewed the data from the Environmental Partnership that are publicly available and find this it could be useful for understanding leak incident rate for member companies. However, the publicly available data from Colorado and the Environmental Partnership do not contain the necessary data to derive an emission factor as provided in the Pacsi *et al.* (2019) and Zimmerle *et al.* (2020) studies used by the EPA including: component-level leak rates, major equipment, site level information, survey method, quantification method, and leak rate.

Additionally, we note that some commenters appear to be misrepresenting conclusions from the Pacsi *et al.* (2019) by stating that the existing default method would overestimate the emissions by 22 to 36 percent and this does not support updated leaker emission factors. We note that in this conclusion presented in the Pacsi *et al.* (2019) study, study authors are comparing the existing population count method results to the study results—not comparing the results of the subpart W leaker method with the study results.

As described in this preamble, the purpose of the OGI enhancement factor is to ensure that irrespective of the survey method, the resulting emissions estimated using the default leaker emission factors represent the emission inventory total as there are inherent differences in the leaks detected when using different survey methods. We have undertaken additional analysis to demonstrate that the final emission factors for Method 21 at a leak definition of 500 ppm, Method 21 at a leak definition of 10,000 ppm, and the OGI emission factors and the survey method specific undetected leak factors successfully estimate the study emissions total. The details of this analysis are presented in the *Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Final Rule—Petroleum and Natural Gas Systems,* which is available in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2023–0234). In summary, the analysis uses the Pacsi *et al.* (2019) activity data (*i.e.,* number of leakers by site type, component type, and survey method) with the final emission factors and undetected leak factor to estimate emissions. The analysis demonstrates that using the proposed emission factors and the undetected leak factor yield emissions that are between 1 and 10 percent of the study total emissions for all survey methods. This analysis supports the use of these factors, and as discussed elsewhere in the preamble to the final rule and in the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* (available in Docket ID. No. EPA–HQ–OAR–2023–0234), the use of the undetected leak factors.

Concerning comments about OGI being determined as BSER for the NSPS, we note that BSER determinations consider technical feasibility, cost, non-air quality health and environmental impacts, and energy requirements. To further the programmatic goals of subpart W, we considered the best available data by which to derive default emission factors to ensure accuracy of the resulting emissions calculations. We find that the purposes of the NSPS and subpart W are inherently different, as one is a standard setting program while the other is a reporting program. Thus, while the determination that OGI is BSER for the NSPS may influence facilities' decision to utilize this method, it does not have bearing on how emissions are quantified under this reporting program.

Comment: Commenters noted that the Zimmerle *et al.* (2020) study showed that emissions from compressor type components have higher leak rates due to vibration. Commenters noted that the EPA did not distinguish between components associated with or not with compressors in its development of the default leaker emission factors. As a consequence, the average proposed emission factors seem to include compressor-related components, which would overstate emissions from the non-compressor related components. Commenters requested that the EPA carefully review the emission factors and consider including compressor related components in the breakdown of the leaker factors.

Response: We agree with commenters that the average leak sizes in the Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) studies were larger for components associated with compressor major equipment. As described previously, the default leaker emission factors were derived by component type (*e.g.,* valves), site type (*i.e.,* gas or oil), and survey method (*e.g.,* OGI) and as noted by commenters did not consider the component's association with compressor or non-compressor equipment. In order to evaluate the impact of considering the association with compressor or non-compressor equipment in the development of default leaker emission factors, we conducted additional analysis. The Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) studies both include attribution of leak measurements to major equipment categories (*i.e.,* compressor, non-compressor, tank) or to major equipment (*e.g.,* compressor, flare, separator), respectively. Therefore, we have utilized this study reported information to further disaggregate our proposed default leaker emission factors into compressor and non-compressor emission factor sets such that the resulting factors are by component type, site type, survey method, and whether they are associated with a compressor or non-compressor, as appropriate. We then applied these emission factors to the Pacsi *et al.* (2019) study activity data (*i.e.,* number of leakers by site type, component type, survey method, and association with compressor or non-compressor major equipment) and undetected leak factor to estimate emissions. The analysis demonstrates that using the compressor and non-compressor emission factors and the undetected leak factor yield emissions that are between 3 and 14 percent lower than the study total emissions for all survey methods. As noted in the previous comment/response in this section of the preamble, we performed an analogous analysis using the proposed default leaker emission factors and found that the estimated emissions were between 1 and 10 percent of the study total. Therefore, the use of the separate compressor and non-compressor emission factors did not result in improved accuracy and tends to further underestimate the emissions when compared to the use of the proposed emission factors. The details of this analysis are presented in the Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Final Rule—Petroleum and Natural Gas Systems, which is available in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2023–0234). We suspect that one reason the separate compressor and non-compressor emission factors do not perform better than the proposed factors is due to the further disaggregation of the leak survey and measurement data from the underlying datasets eroding the sample size that informs the emission factors. This means that any accuracy that may be gained by disaggregating emission factors into compressor or non-compressor categories is offset by the reduction in sample size for the development of such a factor. Based on the results of this analysis, we are finalizing the default leaker factors based on component type, site type, and survey method only basis, as proposed.

Comment: Commenters stated that they could not determine how the proposed default leaker emission factors for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting had been developed. Specifically, one commenter performed a side-by-side comparison of the default leaker emission factors in the Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) studies and those included in the 2023 Subpart W Proposal, noting that they could not match the values.

Response: A detailed explanation and tables were included in the TSD for the proposed rule explaining how the emission factors were derived. We note that the Zimmerle *et al.* (2020) study provided separate emission factors for compressor and non-compressor components and as noted in the previous response and explained in the TSD, the EPA has combined all of the Zimmerle *et al.* (2020) data with the Pacsi *et al.* (2019) data to develop the OGI emission factor set. We also note that we consider the Zimmerle *et al.* (2020) data to be for gas sites only, consistent with the categorization of onshore petroleum and natural gas gathering and boosting equipment in subpart W. We used the study reported site type (*e.g.,* oil or gas) in the Pacsi *et al.* (2019) data to determine the service type for the purposes of aggregating data by site type when developing the default leaker emission factors. So, there may be differences in the precise values because of the assumptions made when combining the study data for the purposes of developing emission factors by component and site type. However, we find that the study published emission factors are in general agreement with those derived by the EPA and our assumptions regarding the aggregation of data are documented in the Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Final Rule—Petroleum and Natural Gas Systems, which is available in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2023–0234).

Comment: Commenters stated that the proposed revisions to leaker emission factors are based on studies for OGI at onshore production and gathering and boosting facilities and are not relevant to midstream (*e.g.,* transmission compression, underground storage) or downstream (*e.g.,* natural gas distribution) sources. Commenters added that the creation of the OGI enhancement factor is not reasonable and is not based on technical data supporting applicability to sources downstream of the onshore production and gathering and boosting facilities. Some commenters recommended that the current OGI leaker emission factors should be retained, as applicable, since it is inappropriate to apply an ''enhancement'' based on analysis of a small dataset from the upstream segment that includes significant disparities in both the operation of equipment (*e.g.,* pressure, CH_4 content) and leak detection environment (*e.g.,* wind conditions). Other commenters recommended that the EPA should consider additional prospective studies and data gathered using OGI and other leak testing methods in other segments of the natural gas supply chain and recommended that the EPA reconsider the OGI enhancement factors and, if appropriate, re-propose them in the future when more data are available.

Response: As demonstrated in the record, we have long contemplated and evaluated study data that demonstrates that there are methodological differences that result in the average leak detected by OGI being higher in magnitude than the leaks detected using Method 21. During the 2016 leaker rule amendments we evaluated a number of studies for equipment leaks in order to inform emission factor updates (see the 2016 TSD; Docket ID. No. EPA–HQ–OAR–2015–0764–0066). These studies included:

- City of Fort Worth Natural Gas Air Quality Study (ERG and Sage, 2011);
- Measurements of Methane Emissions at Natural Gas Production Sites in the United States, Supporting Information (Allen *et al.,* 2013);
- Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol (Subramanian *et al.,* 2015).

In the 2016 TSD, we identified, analyzed and discussed the overall finding that equipment leaks detected with OGI were higher than those detected using Method 21. For reference, a summary of our analyses and conclusions at the time are included here:

- For onshore production and gathering and boosting, we compared the data in the 2011 Fort Worth study (ERG and Sage, 2011) and Allen *et al.* (2013) studies, which are OGI-based fugitive emissions studies and which appear to yield higher leaker emission factors than the EPA Method 21-based data presented in the 1995 EPA Protocol (the basis for the existing subpart W leaker emission factors for Onshore Production and Gathering and Boosting). In order to better understand the variability in leaker emission factors from different studies, we conducted Monte Carlo analyses using the study data. Based on these analyses, random samples of 30 leaking components can be expected to yield average leaker emission factors that vary by a factor of 2 to 3 and samples of 100 leaking components can expected to yield average leaker emission factors that vary by a factor 1.5 to 2. Although this does not directly show that OGI-determined leaker emission factors are necessarily different than EPA Method 21-determined leaker emission factors, if leak rate variability were the only reason for the differences in leaker emission factors, we would expect that the EPA Method 21 leaker emission factors would be higher than the OGI leaker emission factors approximately 50 percent of the time. The fact that the OGI leaker emission factors are consistently higher than the EPA Method 21 leaker emission factors (using a leak threshold of 10,000 ppmv) in essentially every case provides evidence that variability alone does not fully explain the data and that OGI ''visualized'' leaks are generally larger than leaks that have measured EPA Method 21 concentrations above 10,000 ppmv.
- We also discussed seeing similar results for the Onshore Natural Gas Transmission Compression industry segment. We compared leaker emission factors derived from OGI-based study (Subramanian *et al.,* 2015) and the EPA

Method 21-based study (Clearstone, 2002; Clearstone 2007) conducted at Onshore Natural Gas Transmission Compression facilities. As shown in the 2016 TSD, not considering the data where the number of measurements were 10 or fewer, the OGI-based leaker emission factor was larger than the EPA Method 21 (at 10,000 ppmv) leaker emission factor for five of the six components, and the one component (valves on compressors) where the OGI-based measurement was smaller, the leaker emission factors are essentially identical. Thus, these data support the conclusions drawn from the production data. Specifically, OGI-based and EPA Method 21 (at 10,000 ppmv) leaker emission factors usually compare within the expected range of a values considering the high variability of individual measurements. Additionally, OGI-based leaker emission factors are consistently larger than EPA Method 21 (at 10,000 ppmv) leaker emission factors, suggesting that variability alone does not explain the differences observed and that the methodological differences in how leaks are identified are also likely to contribute to the consistently higher OGI-based leaker emission factors.

Since the 2016 final rule, the EPA has obtained additional data that demonstrate the same finding—that OGI detects larger leaks than EPA Method 21. First, we note that gathering and boosting sites could be considered similar to transmission compression sites in that they have many compressors and associated pipeline connections. As described in the subpart W 2023 proposed rule TSD, the Zimmerle *et al.* (2020) study was performed at gathering and boosting sites where OGI surveys were performed to detect leaks, which were then quantified. When comparing the leaker emission factors developed using the Zimmerle *et al.* (2020) study to those in the existing subpart W for Method 21 at either leak definition, the OGI leaker emission factors are higher for all component types. On the basis of the similarities in operating equipment between gathering and boosting sites and transmission compression sites and the observations of average leak sizes in the Zimmerle *et al.* (2020) data as compared to Method 21, we continue to expect that these findings apply across the supply chain.

Further, the Pacsi *et al.* (2019) study that compared OGI and Method 21 side-by-side at multiple production and gathering and boosting sites supports the conclusion that OGI and Method 21 detect different populations of leakers, and that generally OGI detects larger leaks. Considering our past review of this issue, including reviewing data specific to midstream industry segments, and the additional data we have obtained since the 2016 final rule, we are promulgating, as proposed, separate OGI emission factors for all industry segments that are required or elect to quantify emissions using the leaker method.

2. Addition of Undetected Leak Factor for Leaker Emission Estimation Methods

a. Summary of Final Amendments

Subpart W currently provides various screening methods for detecting leaking components in 40 CFR 98.234(a). Each method includes a unique instrument and associated procedure by which leaks are detected. Variability inherently exists in each method's ability to detect leaks, which can be attributed to reasons associated with the instrument, leak detection procedures, the operator or site conditions. For the 2023 Subpart W Proposal, we reviewed recent study data from Pacsi *et al.* (2019) in which multiple leak detection methods, including OGI and Method 21, were deployed alongside one another at the same sites. This study demonstrates that there are undetected leaks for each method. Based on the Pacsi *et al.* (2019) study data, OGI observes 80 percent of emissions from measured leaks, Method 21 at a leak definition of 10,000 ppm observes 65 percent of emissions from measured leaks, and Method 21 at leak definition of 500 ppm observes 79 percent of emissions from measured leaks. In order to account for the quantity of emissions that remain undetected by each screening method, we are finalizing as proposed to provide a method specific adjustment factor, k, for the calculation methods used to quantify emissions from equipment leaks using the leaker method in 40 CFR 98.233(q). We are finalizing as proposed that, if other methods including illuminated infrared laser beam or acoustic leak detection devices are used to conduct leak surveys, the final OGI adjustment factor, k, must be used in the calculation to quantify the emissions from the leaks identified using these other monitoring methods. The addition of a method specific adjustment factor under the final rule will improve the accuracy of emissions data, consistent with section II.B. of this preamble. Further detail on the development of the adjustment factor for each of these screening methods is provided in the subpart W TSD, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add an undetected leak factor for the leaker emission estimation method.

Comment: Some commenters were opposed to the addition of an undetected leak factor, while others expressed support for the addition of this factor.

Commenters who were not in favor of the factor stated that including this factor implies that operators are not making efforts to comply with leak detection and repair (LDAR) federal and state regulatory programs. Commenters also stated that instead of imposing an undetected leak factor, the EPA should emphasize proper training relative to the survey methods to ensure the accuracy of the survey results. Some commenters suggested that the EPA remove the undetected leak factor all together while others recommended that the EPA remove the adjustment factor when direct measurement is used to quantify emissions.

Commenters stated that leaks were detected at only five ''boosting and gathering'' sites included in the Pacsi *et al.* (2019) study results that are the basis for the undetected leak factor value and thus, development of an undetected leak factor does not accurately represent the entirety of the sector and does not qualify as a statistically significant dataset of empirical data to apply to reporting facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment.

Similarly, several commenters stated that the undetected leak factor was developed using data from upstream facilities, which are not representative of the operating equipment (*e.g.,* pressure, CH_4 content) and leak detection environment (*e.g.,* wind conditions) in industry segments downstream of the Onshore Petroleum and Natural Gas Production or Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. Thus, the undetected leak factor should not be applied to emission estimates for those industry segments until such time that sector-specific studies are conducted that demonstrate the applicability of a such a factor to their operations.

Some commenters stated that they could not replicate the calculations the EPA used to estimate the undetected leak factor and requested that the EPA provide additional information on the derivation. These commenters also requested that the EPA test their ''k'' factors by applying to the Method 21 data in order to recalculate the emissions at the site level using study data and confirm if it matches with the measured emissions.

Response: The undetected leak factor is based off the best available data where both OGI and Method 21 detection methods were used and the emissions directly quantified (*i.e.,* the Pacsi *et al.* (2019) study). In our review of OGI and Method 21 equipment leak studies, we note that the performance of the survey method is more aligned with technological and methodological differences rather than the location of the equipment or components. As discussed in section III.P.1.b. of this preamble, when available we have evaluated data of midstream and downstream segments including direct comparisons of OGI and Method 21 data.

We have undertaken additional analysis regarding the use of separate OGI emission factors and the undetected leak factor. The details of this analysis are presented in the *Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Final Rule—Petroleum and Natural Gas Systems,* which is available in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2023–0234). In summary, the analysis uses the Pacsi *et al.* (2019) activity data (*i.e.,* number of leakers by site type, component type, and survey method) with the final default leaker emission factors and undetected leak factor to estimate emissions. The analysis demonstrates that using the final default leaker emission factors and the undetected leak factor yields emissions that are within 10 percent of the study total emissions considering leaks identified across all leak survey methods. This analysis demonstrates that the use of the undetected leak factor is necessary to scale surveyed emissions to accurately estimate the actual quantity of emissions in the inventory. We maintain that the use of the undetected leak factor enhances the accuracy of the emissions calculation such that they more accurately represent the total emissions quantity of equipment leaks and we are finalizing the method-specific undetected leak factors, as proposed.

We note that commenters requested that the EPA compare the emissions that would be estimated using the final default leaker emission factors and the undetected leak factor at the site level to the measured value from the Pacsi *et al.* (2019) study. Concerning this request, we note that the default leaker factors are average study-derived emission factors, and thus we would not expect that the emissions resulting from applying an average default leaker emission factor to a single site with a handful of measurements to match. Equipment leak emissions are highly variable and exhibit lognormal distribution such that the emissions for a single component leak can be an order of magnitude or more higher or lower than the average across a large number of components. The inherent variability in the measurements means there is more uncertainty when applying an emission factor, which can be minimized by increasing sample size in the underlying dataset. In this rule, we provide that surveys must be conducted and reported at the well site or gathering site level, and also aggregated at the facility level. Based on our analysis using the study-level data from Pacsi *et al.* (2019), we expect the facility-level aggregation of site level emission estimates to reflect the actual emissions.

Some commenters noted that the derivation of the undetected leak factors is unclear. We note that a detailed explanation and tables were included in the TSD for the proposed rule. In order to increase transparency in the record, we are providing additional details regarding derivation in the *Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Final Rule—Petroleum and Natural Gas Systems,* which is available in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2023–0234).

3. Addition of Method To Quantify Emissions Using Direct Measurement

a. Summary of Final Amendments

As an alternative to the final revised default leaker emission factors, we are also finalizing as proposed in 40 CFR 98.233(q)(1) to provide an option (provided in final 40 CFR 98.233(q)(3)) 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.B. of this preamble. The final amendments would provide that facilities with components subject to 40 CFR 98.233(q) can elect to perform direct measurement of leaks using one of the existing subpart W measurement methods in 40 CFR 98.234(b) through (d), such as calibrated bagging or a high volume sampler. To use this option under the final provisions, 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, final 40 CFR 98.233(q)(1) specifies that a complete leak detection survey is the fugitive emissions monitoring of a well site using a method in 40 CFR 98.234(a) 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 site. For the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, final 40 CFR 98.233(q)(1) specifies that a complete leak detection survey is the fugitive emissions monitoring of a compressor station using a method in 40 CFR 98.234(a) 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 at a ''gathering and boosting site'' (and we are finalizing amendments to define this term in 40 CFR 98.238, as described in section III.D. 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 is also required to be facility-wide. In other words, this option allows the use of measurement data directly when all leaks identified are quantitatively measured. After consideration of comments, under the final rule we are finalizing the addition of provisions for substituting measurement data for components that require elevating the measurement personnel more than 2 meters above the surface and a lift is unavailable at the site or would pose immediate danger to measurement personnel performing the direct measurement using one of the methods in 40 CFR 98.234(a). These final provisions will allow facilities to substitute measurement data only for components meeting these criteria with the component-specific and service-specific default leak rate in final tables W–2, W–4, or W–6, as applicable. We are also updating from proposal the term ''well-pad'' in proposed 98.233(q)(1)(vii)(D) to the newly defined ''well-pad site'' term in the final provision (see section III.D. of this preamble) to clarify that, for onshore production sites not subject to NSPS OOOOb or EG OOOOc that elect to conduct leak detection surveys, a complete leak detection survey must include all components at a single well-pad and associated with that single well-pad. Also after consideration of comments, for the natural gas distribution industry segment, we are finalizing new amendments to the use of Calculation Method 2 for facilities utilizing a multi-year survey cycle to specify the use of volumetric emissions, rather than mass emissions, resulting from this method to determine the meter/regulator run population emission factor in accordance with 40 CFR 98.233(q)(viii)(A). This change will simplify the process of using the measurement data to develop the population emission factor for facilities using a multi-year survey cycle. Additionally, we are also finalizing two corrections to cross-references in 40 CFR 98.233(q)(3) and the related ''CountMR'' and ''Es,e,i'' variables in 40 CFR 98.233(r) as a result of consideration of public comments and EPA review.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add a method to quantify emissions from equipment leak surveys using direct measurement.

Comment: Commenters stated that there may be situations at a facility where direct measurement is not feasible or safe to conduct, thus meaning the survey that did not include measurements for these components would be considered incomplete and as a result facilities would not be able to use the direct measurement option. Commenters added that excluding components for which measurement is infeasible or unsafe should not prevent reporters from conducting direct measurement of equipment elsewhere on the facility. Commenters asserted that the EPA's proposal disincentivizes the use of direct measurement, the most accurate means of emission quantification. Commenters requested that the EPA allow reporters the option to use direct measurement and/or EFs as appropriate during a complete leak detection survey.

Response: We understand and agree with commenters that there may be components that are difficult or unsafe to measure. We are finalizing provisions in 40 CFR 98.233(q)(3)(i) to provide for the use of substitute measurement data for components that require elevating the measurement personnel more than 2 meters above the surface and a lift is unavailable at the site or would pose immediate danger to measurement personnel performing the direct measurement using one of the methods in 40 CFR 98.234(a). These final provisions will allow facilities to substitute measurement data only for components meeting these criteria with the component-specific and service-specific default leak rate in final tables W–2, W–4, or W–6, as applicable. The use of substitute data will also ensure that a facility electing to use the direct measurement option can still successfully perform a complete leak detection survey as required by this option. The final amendments narrowly define when data substitutions can be used to ensure the accuracy of the estimate while accommodating feasibility and promoting safety.

Comment: Commenters supported the option for facilities to calculate their emissions based on the results of direct measurement. Commenters noted that in order for natural gas distribution facilities to use the measurement option, facilities must perform a complete leak detection survey, which for natural gas distribution companies may take up to 5 years depending on the length of the survey cycle. Commenters then requested that natural gas distribution companies/utilities be allowed to continue using their previous T–D emission factors for any stations that have not yet been subject to direct measurements until such time as all of that LDC's stations have gone through one full cycle of surveying. Commenters stated that under this approach, once the full cycle of measuring all T-Ds has been completed, the previous emission factors would no longer be used.

Response: Under the existing subpart W provisions, natural gas distribution companies must survey their above grade transmission distribution transfer stations and may elect to do so over a single or multi-year survey cycle not to exceed five years. If leaks are detected at the above grade transmission distribution transfer stations during these surveys, the emissions are quantified using equation W–30 with the count of leaks, the default leaker emission factor, and the total time the surveyed component was assumed to be leaking and operational. The emissions from the above grade transmission distribution transfer stations are used with equation W–31 to develop a facility-level meter/regulator run population emission factor, which, depending on the length of the survey cycle, is applied to the count of meter/regulator runs at all above grade transmission distribution transfer stations and/or the count of meter/regulator runs at above grade metering-regulating stations. The facility-level meter/regulator run population emission factor must be calculated annually, which for facilities electing a multi-year survey cycle means the results of the current calendar year leak survey and the results from prior year leak surveys are included in the calculation of the meter/regulator run population emission factor on a rolling basis such that a full survey cycle of results is included.

Through this final rulemaking, natural gas distribution companies will now have the option to either continue to use the default leaker emission factors and equation W–30 to quantify equipment leak emissions from their above grade transmission distribution transfer stations or perform direct measurement of leaking components found during the equipment leak surveys conducted at their above grade transmission distribution transfer stations. The emissions from their above grade transmission distribution transfer stations—whether based on calculations using default leaker emission factors or direct measurements—must still be used with equation W–31 to develop a facility-level meter/regulator run population emission factor. The facility-level meter/regulator run population emission factor must still be applied to the count of meter/regulator runs at all above grade transmission distribution transfer stations and/or the count of meter/regulator runs at above grade metering-regulating stations, depending on the length of the survey cycle, to estimate emissions from these stations. The facility-level meter/regulator run population emission factor must still be updated annually. For the first few years following the effective date of the direct measurement option provided in this final rule, for facilities that elect to survey over a multi-year survey cycle and that elect to use the direct measurement option, the developed facility-level meter/regulator run population emission factor will be informed by emissions quantities at above grade transmission distribution transfer stations that were estimated using default leaker emission factors (*i.e,* the existing method) and direct measurement (*i.e,* the new method). For example, if a facility elects to survey all their stations over a 2-year survey cycle and for Year 1 they use the existing method (*i.e,* equipment leak surveys of their above grade transmission distribution transfer stations, leaks quantified using the default leaker emission factors) and for Year 2 they use the new method (*i.e,* equipment leak surveys of their above grade transmission distribution transfer stations, leaks quantified using direct measurement), the resulting facility-level meter/regulator run population emission factor will be informed by emissions calculated using the existing and new calculation methods. This is expected to be temporary and only be an issue for no more than five years (*i.e,* the maximum survey cycle length) and only for the subset of facilities that elect a multi-year survey cycle and elect to use the direct measurement option.

Concerning the comment that natural gas distribution companies electing to survey over a multi-year survey cycle and electing to use the direct measurement option should be able to use their historical facility-level meter/regulator run population emission factors (*i.e,* based on the existing method) until a survey cycle incorporating only direct measurement data has been completed, we find that natural gas distribution companies will obtain the necessary data by following the direct measurement method (*i.e,* the volumetric emissions by component type) to combine with the volumetric emissions from historical surveys (*i.e,* the volumetric emissions calculated according to equation W–30) for the prior year facility-level meter/regulator run population emission factor development to continue to estimate the facility-level meter/regulator run population emission factors in accordance with equation W–31. Therefore, we do not see a need to provide that historical facility-level meter/regulator run population emission factors can be used until such time that a complete survey cycle including only direct measurements of all stations has been completed. Consequently, as described above we acknowledge that for a limited period of time and limited number of facilities, this means that the facility-level meter/regulator run population emission factors may have a mix of emissions data calculated using the default leaker emission factors (*i.e,* the existing calculation method) and direct measurements (*i.e,* the new leaker measurement method).

In considering these comments, we performed a review of the proposed procedures for utilizing the leaker measurement method for natural gas distribution companies. We proposed in 40 CFR 98.233(q)(3)(viii)(A) that in order to determine the CO_2 and CH_4 facility-level meter/regulator run population emission factor using equation W–31, reporters were to use equation W–31 and the mass emissions calculated in accordance with 40 CFR 98.233(q)(3)(vi). During our review, we noted that the historical facility-level population emission factors have been calculated on a volumetric basis (*i.e,* the resulting population emission factor from equation W–31 has units of measure of standard cubic feet of GHGi per operational hour of all meter/regulator runs) and the provisions for estimating emissions utilizing the facility-level meter/regulator run population emission factors in 40 CFR 98.233(r) requires a volumetric based emission factor. Therefore, we are finalizing amendments to 40 CFR 98.233(q)(3)(viii)(A) to instead require that for reporters electing to use the direct measurement option and using equation W–31 to develop their facility-level meter/regulator run population emission factor use the sum of the volumetric emissions at standard conditions by component type required to be surveyed calculated in accordance with 40 CFR 98.233(q)(3)(iv) rather than mass emissions as was proposed. This simplifies the use of the direct measurement data as it does not require conversion to mass emissions. This change also allows reporters electing to perform a multi-year survey cycle to more easily combine historical volumetric emission rates with direct measurements to develop their meter/regulator run population emission factors.

4. Addition of a Method To Develop Site-Specific Component-Level Leaker Emission Factors

a. Summary of Final Amendments

As noted in section III.P. of this preamble, facilities are currently required to perform leak surveys to determine the number of leaking components. The results of these surveys (*i.e.*, the count of leakers) are used with default emission factors to estimate the quantity of resulting emissions. As noted in the previous section of this preamble, the EPA is finalizing as proposed an additional option for facilities to conduct leak surveys and perform direct measurement to quantify the emissions from equipment leak components.

The EPA recognizes that while direct measurement is the most accurate method for determining equipment leak emissions, it may also be time consuming and costly. In consideration of both the advantages of and potential burdens associated with direct measurement, the EPA is also finalizing a method to use direct measurement from leak surveys to develop component level emission factors based on facility-specific leak measurement data. The facility-specific emission factors would provide increased accuracy over the use of default emission factors, consistent with section II.B. of this preamble, while lessening a portion of the burden of directly measuring every leak.

We are finalizing as proposed that all facilities that elect to follow the direct measurement provisions in proposed 40 CFR 98.233(q)(3)(i) must track the individual measurements of natural gas flow rate by specific component type (valve, connector, *etc.,* as applicable for the industry segment) and leak detection method for the development of facility-specific component-level leaker emission factors. We are finalizing three different bins for the leak detection methods: Method 21 using a leak definition of 500 ppm as specified in 40 CFR 98.234(a)(2)(i); Method 21 using a leak definition of 10,000 ppm as specified in 40 CFR 98.234(a)(2)(ii); and OGI and other leak detection methods as specified in 40 CFR 98.234(a)(1), (3), or (5). We are finalizing as proposed that reporters must compile at least 50 individual measurements of natural gas flow rate for a specific component type and leak detection method (*e.g.,* gas service valves detected by OGI) before they can develop and use the facility-specific emission factors for the component types at the facility. Based on consideration of comments received on the 2023 Subpart W Proposal, we are finalizing a change from proposal to the terminology of the emission factor from ''site-specific'' to ''facility-specific'' to better characterize the application of the developed emission factor, which is to be at the facility-level based on site-level measurement data for certain industry segments. We are finalizing as proposed that these flow rate measurements are required to be converted to standard conditions following the procedures in 40 CFR 98.233(t). We are also finalizing as proposed that the volumetric measurements comprised of at least 50 measured leakers must then be summed and divided by the total number of leak measurements for that component type and leak detection method combination. The resulting value will be an emission factor in units of standard cubic feet per hour-component (scf/hr-component). This facility-specific emission factor must be used, when available, to calculate equipment leak emissions following the procedures in 40 CFR 98.233(q)(2). Because some equipment component types are more prevalent and more likely to reach 50 leak measurements than other components, application of the calculation methodology in 40 CFR 98.233(q)(2) may include default leaker factors for some components and facility-specific leaker factors for other components.

We are also finalizing as proposed in 40 CFR 98.236(q) to require that the emissions be reported at the aggregation of calculated or measured values for the combination of component type and leak detection method. As discussed in more detail in section III.P.1. of this preamble, numerous studies have shown that different leak detection methods identify different populations of leaking components; therefore, consistent with the delineation of the default emission factors by leak detection method, site-specific emission factors are delineated in the same way under the final provisions.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to add a method to develop a site-specific component-level leaker emission factor.

Comment: Commenters noted that the EPA's intent to allow for site-level measurement data to be used to develop a representative facility-level emission factor was clear from the discussion in the preamble to the 2023 Subpart W Proposal, however the use of the term ''site-specific'' in 40 CFR 98.233(q)(3) may make this intent less clear. Therefore, commenters requested that the EPA clarify that only a facility-wide emission factor based on direct measurement at a representative sampling of well sites is needed.

Response: We are clarifying in the final provisions that the site-specific emission factor approach in proposed 40 CFR 98.233(q)(4) provides for the development of an emission factor that is applied at the facility-level. For example, consistent with the description in the preamble to our proposed rule, for the purposes of subpart W, an onshore production facility may be comprised of multiple well sites. The survey and measurement of all subject equipment leak components using the methods in 40 CFR 98.234(a) at a well site constitutes a complete leak detection survey of that well site. The measurements obtained must be included in the component-specific datasets underlying the site-specific emission factor. Once sufficient measurements are made, the site-specific emission factor developed in accordance with proposed 40 CFR 98.233(q)(4) may be applied to equipment leak components at any of the well sites within the basin that comprise the onshore production subpart W facility. In order to make this clearer, the final terminology changes the name from the proposed ''site-specific'' to the final ''facility-specific'' emission factor.

Comment: Commenters stated that the requirement to accumulate a minimum of 50 leak measurements for a given component and leak detection method combination was impractical and could take many years of surveys. Some commenters stated that the EPA has not justified why a minimum of 50 measurements is appropriate and reasonable. Some commenters added that the minimum number of measurements proposed may disincentivize measurement and penalize operators with a small number of sites. Other commenters recommended a tiered approach whereby the minimum number of leak measurements would be determined by the number of well sites or gathering and boosting sites comprising the GHGRP onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facility, respectively. Other commenters recommended the EPA allow the development of site-specific emission factors at the company level where owners/operators could combine measurements from multiple GHGRP facilities together to develop the emission factors. Some commenters also stated that the component and survey method specific default leaker emission factors developed using the combination of data from the Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) studies did not meet the measurement minimum the EPA proposed for the development of site-specific emission factors.

Response: We have considered the comments received on the minimum number of measurements (*i.e.*, 50) required by component type and survey method combination to meet the criteria for development of a facility-specific emission factor as proposed in 40 CFR 98.233(q)(4). We have performed additional analysis of the reported leaker data to assess these comments. The details of these analyses are presented in the Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Final Rule—Petroleum and Natural Gas Systems, which is available in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2023–0234). We generally find that this approach was provided to reduce the burden of measurement, while increasing the accuracy of the associated emission estimate over that of using a default leaker emission factor since it is based on sufficient facility-specific measurements to be considered statistically representative.

The first analysis we performed was to determine the average number of leakers by component type and industry segment per facility-year. We find that for components that are more commonly found in service (*e.g.*, valves, connectors), a facility-specific emission factor could be developed in 5 years or less for facilities in the onshore production, gathering and boosting, underground storage and LNG import/export industry segments based on the historical count of leakers per facility-year. Conversely, we agree with commenters that for some industry segments (*e.g.*, processing, transmission compression, LNG storage, NGD) and some types of components (*e.g.*, OEL, Pump Seals), it may take many years to accumulate sufficient measurements to develop a facility-specific emission factor. For example, OEL and pump seals have very low (if any) reported leakers on average per facility-year for any of the 7 industry segments. In this case, reporters may decide that using this method for these components may not be reasonable. However, facilities would still be able to use the default emission factor for these components or continue to take their own measurements to ensure the accuracy of the reported data.

The provisions to directly measure and develop a facility-specific emission factor is one of several options to quantify emissions from equipment leaks. Regarding the comments to allow for the development of company specific emission factors, we note that the equipment leak provisions for direct measurement are based on measurements aggregated at a facility level. If we were to include an option for facilities to develop a company level emission factor, facilities with multiple GHGRP facilities may not have to measure every facility to develop a company level emission factor. We do not believe that extrapolating an emission factor based on a select subset of facilities across all facilities that are part of the corporate entity would be appropriate. Subpart W allows corporate emission factors for compressors because as found measurements are required for every compressor at all facilities in the corporate entity, ensuring representativeness. However, in this case measurements are not required at every facility (*i.e.*, facilities can elect the leaker method, the direct measurement method or the population count method, as applicable) such that the company level emission factor may not be representative of all facilities. That is, owners may look to conduct measurements only at newer facilities or facilities that are otherwise expected to have lower emissions, and therefore potentially bias the corporate emission factor. Therefore, we are not providing an option for component level leaker emission factors to be developed at the company level and are maintaining our proposed facility-specific emission factor method.

The second analysis we performed was to utilize the combined Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) dataset and the resulting proposed leaker emission factors to perform a statistical analysis. In this analysis, we sought to determine the impact of sample size on the EF for each component. For example, for leaking connectors detected with OGI at gas sites, the combined dataset of the Zimmerle *et al.* (2020) and Pacsi *et al.* (2019) studies contain 217 measurements for this component type. In this analysis, a range of sample sizes was simulated for each component. Each sample size was simulated 10,000 times by sampling the available data with replacement, meaning no data points were removed from the available data when developing the distribution and, thus, could be chosen again during the simulations. We then compared the distribution of the estimated emission factor against the number of samples in the simulations.

Across all components, the analysis demonstrates that 90 percent of the simulated emission factors fall within ±40 percent of the study estimated emission factor when using 50 samples; ±30 percent of the study estimated emission factor when using 100 samples; and ±20 percent of the study estimated emission factor using 200 samples. Therefore, we continue to maintain that sample size is of critical importance when developing emission factors and a minimum of 50 measurements appears to be provide reasonable accuracy while considering the burden and duration of survey/measurement campaigns for this option based on this analysis.

Finally, in response to comments that we are utilizing emission factor datasets (*i.e.*, Pacsi/Zimmerle) that are not as robust as the minimum requirements for developing facility-specific emission factors, we note that we consistently strive to use up-to-date studies that provide the necessary data to derive emission factors, but we are limited to what is available that meets our purpose. This process is also open to stakeholder engagement in which stakeholders can recommend studies or provide data to better inform decisions related to emission factor development. In this case, we combined data from multiple studies to increase sample size and for the many of components we meet or exceed the minimum in proposed 40 CFR 98.233(q)(4).

5. Removal of Additional Method 21 Screening Survey for Other Screening Survey Methods

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 currently 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) (finalized at 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 2016 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 of the preamble, the average emissions of leakers identified by OGI are greater than for 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 will provide the most accurate estimate of emissions, while selectively screening OGI-identified leaks using Method 21 to reduce the number of reportable leakers will yield a low bias in the reported emissions. Additionally, this will be incongruous with the application and supporting rationale of the monitoring method-specific adjustment factor, k (where the k value for Method 21 with a leak definition of 10,000 ppm will need to be applied), which we are finalizing in this action, if OGI-identified leaks could be considered non-leaks based on subsequent Method 21 monitoring. For these reasons, we are finalizing as proposed to require reporters to directly use the leak survey results for the monitoring method used to conduct the complete leak survey and are finalizing as proposed to eliminate this additional Method 21 screening provision. These final amendments are expected to provide more accurate emissions data, consistent with section II.B. of this preamble. The EPA did not receive any comments regarding these proposed amendments.

6. Amendments Related to Oil and Natural Gas Standards and Emissions Guidelines in 40 CFR Part 60

a. Summary of Final Amendments

As noted in the introduction to section II. of this preamble, the EPA recently finalized NSPS OOOOb and EG OOOOc for certain oil and natural gas new and existing affected sources, respectively. Under the final standards in NSPS OOOOb and the final presumptive standards in EG OOOOc, owners and operators will be required to implement a fugitive emissions monitoring and repair program for the collection of fugitive emissions components at well site, centralized production facility and compressor station affected sources. In addition, the final NSPS OOOOb and EG OOOOc include a final appendix K to 40 CFR part 60, specifying an OGI-based method for detecting leaks and fugitive emissions from all components that is not currently provided in subpart W. The EPA also finalized 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 finalizing amendments to revise the calculation methodology for equipment leaks in subpart W largely as proposed so that data derived from equipment leak and fugitive emissions monitoring using one of the methods in 40 CFR 98.234(a) conducted under NSPS OOOOb or the applicable approved state plan or applicable Federal plan in 40 CFR part 62 must be used to calculate emissions, consistent with section II.B. of this preamble.

First, under these final amendments, as proposed, facilities with certain fugitive emissions components at a well site, centralized production facility or compressor station subject to NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 will be required to use the data derived from the NSPS OOOOb or applicable 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, as proposed, the final amendments expand the existing cross-reference to 40 CFR 60.5397a to also include the analogous requirements in NSPS OOOOb or 40 CFR part 62. Facilities with fugitive emissions components not subject to the standards in NSPS OOOOb or addressed by standards in a state or Federal plan following EG OOOOc will 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 a state or Federal plan in 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) will continue to have the opportunity to voluntarily use the proposed leak detection methods to calculate and report their GHG emissions to the GHGRP in accordance with the final provisions. We also note that there are facilities with certain fugitive emissions components at a well site, centralized production facility or compressor station that are subject to NSPS OOOOb, but are not required to monitor these fugitive emission components using the survey methods in 40 CFR 98.234(a) (*e.g.*, single wellhead only site, which is required to survey using AVO). For these facilities, we are finalizing the option in 40 CFR 98.233(q)(1)(iv) for facilities to elect to conduct equipment leak surveys at these sites in accordance with the methods in 40 CFR 98.234(a) in lieu of calculating emissions from these sites in accordance with 40 CFR 98.233(r). To facilitate these final provisions, we are also finalizing clarifications in 40 CFR 98.233(q)(1)(vii)(B) and (C) that fugitive emissions monitoring conducted using one of the methods in 40 CFR 98.234(a) to comply with NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62, respectively, 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 will be able to comply with the requirement to use NSPS OOOOb or 40 CFR part 62 fugitive emission surveys directly for their subpart W reports. We are also finalizing an amendment to move the specification that fugitive emissions monitoring conducted to comply with NSPS OOOOa is considered a ''complete leak detection survey'' from existing 40 CFR 98.233(q)(2)(i) to 40 CFR 98.233(q)(1)(vii)(A) so that all the provisions regarding what constitutes a ''complete leak detection survey'' are together. In a corresponding amendment, we are also finalizing an expansion of the current reporting requirement in existing 40 CFR 98.236(q)(1)(iii) (final 40 CFR 98.236(q)(1)(iv)) to require reporters to indicate if any of the surveys of well sites, centralized production facilities 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.[68]

Second, we are finalizing as proposed revisions to 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. Specifically, the EPA is finalizing the amendments 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 will consolidate the OGI-based methods in 40 CFR 98.234(a)(1). Similarly, the EPA is finalizing revisions to 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 final amendment will effectively move 40 CFR 98.234(a)(7) to 40 CFR 98.234(a)(2)(ii). We are also finalizing that the references to ''components listed in § 98.232'' will 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) will be moved to 40 CFR 98.234(a)(1)(ii) and 40 CFR 98.234(a)(2), as applicable.

In March 2024, the EPA finalized in NSPS OOOOb and EG OOOOc that owners and operators of natural gas processing facilities will detect leaks using an OGI-based monitoring method following the final appendix K to 40 CFR part 60 (89 FR 16820). We are finalizing as proposed amendments to include that same method in subpart W at 40 CFR 98.234(a)(1)(iii) to ensure that reporters of those facilities will be able to comply with the 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. In addition, as part of the final NSPS OOOOb and EG OOOOc, the EPA finalized an alternative periodic screening approach for fugitive emissions from well sites, centralized production facilities and compressor stations under 40 CFR 60.5398b(b) that will allow the use of advanced technologies approved under 40 CFR 60.5398b(d) to detect large equipment leaks. Under the NSPS OOOOb and EG OOOOc final rule, if emissions are detected using an approved advanced technology, facilities will be required to conduct monitoring using OGI or Method 21 to identify and repair specific leaking equipment. Additionally, under the NSPS OOOOb and EG OOOOc final rule, even if no emissions are identified during a periodic screening survey, some facilities using these advanced technologies will still be required to conduct annual fugitive emissions monitoring using OGI. The EPA's intent in this final rule for subpart W is that the results of those NSPS OOOOb and 40 CFR part 62 OGI or Method 21 surveys will 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 included in the leak detection methods provided in subpart W. Thus, after further consideration, including consideration of comments we received on the 2023 Subpart W Proposal, we are finalizing new amendments that will require the reporting of fugitive emissions monitoring survey results conducted to comply with the alternative periodic screening approach in the NSPS OOOOb, including annual affected facility-level OGI surveys pursuant to 40 CFR 60.5398b(b)(4) and affected facility-level ground based monitoring surveys pursuant to 40 CFR 60.5398b(b)(5)(ii).

Third, we are finalizing as proposed subpart W requirements for onshore natural gas processing facilities consistent with certain requirements for equipment leaks in the final NSPS OOOOb or EG OOOOc. Currently, onshore natural gas processing facilities

[68] We are similarly finalizing as proposed a revision to the existing reporting requirement in subpart W 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).

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 the final NSPS OOOOb and the EG OOOOc presumptive standards, owners and operators must conduct bimonthly (*i.e.*, once every other month) OGI monitoring in accordance with 40 CFR part 60, appendix K to detect equipment leaks from pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor or light liquid service, connectors in gas/vapor or light liquid service, and closed vent systems in accordance with 40 CFR 60.5400b and 60.5400c, respectively. As an alternative to the bimonthly OGI monitoring, EPA Method 21 may be used to detect leaks from the same equipment at frequencies specific to the process unit equipment type (*e.g.*, monthly for pumps, quarterly for valves) in accordance with 40 CFR 60.5401b and 60.5401c, respectively. Open-ended valves and lines, pumps, valves and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service must be monitored using AVO. For the alternative approach provided in NSPS OOOOb and EG OOOOc using EPA Method 21, 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 finalizing in 40 CFR 98.233(q)(1)(vii)(F) that 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 must use the data derived from each equipment leak survey conducted as required by NSPS OOOOb or the relevant subpart of 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 final amendment, onshore natural gas processing facility reporters will 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, reporters subject to NSPS OOOOb or 40 CFR part 62 will 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 are also finalizing as proposed 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 final THC leaker emission factors for the ''other'' component type are of the same value as the THC leaker emission factors for the ''other'' component type for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (existing table W–3A and table W–4A to subpart W, respectively, final table W–4 to subpart W). For more information on the derivation of the original emission factors, see the 2010 subpart W TSD,[69] and for more information on the derivation of the ''other'' component type emission factor proposed to be applied to these types of leaks at facilities in the Onshore Natural Gas Processing industry segment, see the TSD for the 2016 amendments to subpart W.[70] In a corresponding amendment, we are also finalizing as proposed the expansion of the reporting requirement in existing 40 CFR 98.236(q)(1)(iii) (finalized 40 CFR 98.236(q)(1)(iv)) 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.

After consideration of comments received on the 2023 Subpart W Proposal, we are finalizing new amendments to cross reference the alternative standards (*i.e.,* use of EPA Method 21), in addition to the emission standard (*i.e.,* bimonthly OGI surveys), for fugitive emission sources in NSPS OOOOb for natural gas processing plants to ensure that all surveys conducted for the NSPS OOOOb are included in subpart W. Additionally, in response to comments on the 2023 Subpart W Proposal, we are codifying a regulatory cross refence that provides an exemption to survey equipment leak components that are considered ''inaccessible'' for natural gas processing plants in 40 CFR 98.233(q)(vii)(F). This exemption only applies to components that are ''inaccessible'' as provided in 40 CFR 60.5401b(h)(3) and 60.5401c(h)(3) for facilities using the EPA Method 21 leak survey method. In the existing subpart W rule, the term ''inaccessible'' is used in 40 CFR 98.234(a)(1), (2), (6) and (7) to refer to equipment leak components that require monitoring personnel to be elevated more than 2 meters off the surface. As stated in the existing rule text, these components are not exempt from monitoring rather they must be monitored using OGI if EPA Method 21 cannot be used to monitor the inaccessible equipment leaks. During rearrangement of the rule text in the 2023 Subpart W Proposal, this language was proposed to be moved and consolidated at 40 CFR 98.234(a). In the NSPS OOOOb and EG OOOOc, the term ''difficult-to-monitor'' is used to characterize components that require monitoring personnel to be elevated more than 2 meters off the surface. In response to comments and in order to be consistent with the terminology in the NSPS OOOOb and EG OOOOc, we are revising the term in the final rule from ''inaccessible'' to ''difficult-to-monitor'' in 40 CFR 98.234(a). We are also making the same revision to change the term ''inaccessible'' to ''difficult-to-monitor'' in 40 CFR 98.233(q)(1)(vii)(F) of the final rule for consistency in the use of the term.

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 final NSPS OOOOb and EG OOOOc presumptive standards) is not consistent with the leak definition in the Method 21 option in the current 40 CFR 98.234(a)(2), 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 final addition of

[69] *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–2023–0234.

[70] *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–2023–0234.

default leaker emission factors for survey methods other than Method 21 (as described previously in this preamble), we are finalizing as proposed several additions to the equipment leak survey requirements for the Onshore Natural Gas Processing industry segment, beyond those amendments already described related to the final NSPS OOOOb and EG OOOOc presumptive standards. First, we are finalizing default leaker emission factors for Method 21 at a leak definition of 500 ppm in final table W–4 to subpart W. As with the final ''other'' component type leaker emission factors, these final leaker emission factors (*i.e.,* valve, connector, open-ended line, pressure relief valve and meter) are of the same value as the THC leaker emission factors for the Onshore Natural Gas Transmission Compression and the Underground Natural Gas Storage industry segments (existing 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.[71] In addition, we are finalizing 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 final amendment will 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).

b. Summary of Comments and Responses

Comment: Commenters expressed support for allowing the results of monitoring surveys conducted in accordance with the NSPS OOOOb and 40 CFR part 62 state plans. Commenters stated that the EPA should, however, allow the use of the results of all monitoring surveys conducted for the NSPS OOOOb and 40 CFR part 62 state plans for reporting, including follow-up surveys.

Response: We are finalizing, with some changes consistent with the proposal to reflect the NSPS OOOOb and EG OOOOc final rules, that the results of monitoring surveys for fugitive emissions components affected facilities conducted under the NSPS OOOOb and EG OOOOc will be required to be reported to subpart W.

NSPS OOOOb and EG OOOOc in 40 CFR 60.5397b and 60.5397c, respectively, provide the emission standards for fugitive emissions components affected and designated facilities, which include initial and subsequent monitoring surveys using AVO, OGI or Method 21 with a leak definition of 500 ppm depending on site type (*e.g.,* single wellhead only well sites, multi-wellhead only well sites).

We are finalizing, as proposed, the provisions that facilities must report the results of equipment leak surveys conducted to comply with 40 CFR 60.5397b and 60.5397c of the NSPS OOOOb and EG OOOOc, respectively, as long as they were conducted using one of the leak survey methods included in subpart W at 40 CFR 98.234(a) (*i.e.,* OGI or Method 21) and constitute a complete leak survey as specified in 40 CFR 98.233(q)(1)(vii).

40 CFR 60.5398b(b) and 60.5398c(b) of the NSPS OOOOb and EG OOOOc, respectively, provide the option to demonstrate compliance with the alternative standards for fugitive emissions components affected and designated facilities using periodic screening. Under those provisions, the periodic screening can be performed using advanced technologies that are approved under 40 CFR 60.5398b(d). Under those provisions, the frequency of periodic screening is determined based on the minimum aggregate detection threshold of the method used to conduct the periodic screenings and site type. Some NSPS OOOOb affected facilities and EG OOOOc designated facilities are required to perform an affected facility-level OGI survey independent of the results of the periodic screening, including the following:

- Well sites and centralized production facilities that contain certain major production and processing equipment, and compressor stations: Bimonthly Screening and ≤10 kg/hr technology detection threshold;
- Well sites or centralized production facilities that contain certain major production and processing equipment, and compressor stations: Monthly Screening and ≤15 kg/hr technology detection threshold;
- Single wellhead only well sites, small well sites, and multi-wellhead only well sites: Triannual and ≤10 kg/hr technology detection threshold; and
- Single wellhead only well sites, small well sites, and multi-wellhead only well sites: Quarterly Screening and ≤15 kg/hr technology detection threshold.

Additionally, under those provisions any periodic screening result with a confirmed detection of emissions found with the approved advanced technology requires a ground-level follow-up survey using OGI or Method 21 with a leak definition of 500 ppm. Depending on the spatial resolution of the approved advanced technology, the follow-up monitoring survey is required at the affected facility level, area-level or component-level. In order to ensure that monitoring surveys conducted in accordance with 40 CFR 60.5398b(b) and 60.5398c(b) of the NSPS OOOOb and EG OOOOc, respectively, which constitute a complete leak detection survey and were conducted using one of the methods in 40 CFR 98.234(a) are also required to be reported to subpart W, we are adding provisions to include these survey results in the final rule. These provisions specifically include the annual OGI surveys required in 40 CFR 60.5398b(b)(4) and 60.5398c(b)(4) as well as the facility-level follow-up monitoring surveys conducted in accordance with 40 CFR 60.5398b(b)(5)(ii) or 60.5398c(b)(5)(ii). The area or component-level monitoring surveys conducted in accordance with 40 CFR 60.5398b(b) and 60.5398c(b) of the NSPS OOOOb and EG OOOOc, respectively, are not considered complete leak detection surveys for purposes of subpart W reporting because the surveys only cover a subset of equipment leak components at each site. The partiality of these area or component-level surveys may not provide representative emissions coverage of each well-pad site or gathering and boosting site. Therefore, we are not allowing inclusion of the NSPS OOOOb and EG OOOOc area or component-level monitoring survey results in the final rule requirements for subpart W. However, we note that reporters may elect to conduct site-level surveys while on site to conduct NSPS OOOOb and EG OOOOc area or component-level surveys, and reporting and use the results of these site-level surveys would then be included in the final rule requirements for reporting under subpart W in accordance with the provisions of 98.233(q)(1)(vii)(D) and (E).

Comment: For natural gas processing facilities, commenters recommended that references to 40 CFR 60.5400b should also include a reference to the

[71] *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–2023–0234.

alternate equipment leak standards in 40 CFR 60.5401b to clarify that both OGI surveys conducted according to Appendix K and Method 21 surveys with a 500 ppmv leak definition should be used in emission calculations. Additionally, specifically for natural gas processing facilities, commenters stated that the inaccessible component exemption in 40 CFR 98.234(a) should be retained under Subpart W. Commenters stated that, for onshore gas processing, the term ''Inaccessible'' has a long-standing meaning under NSPS, which historically is limited to connectors that are monitored using Method 21 with specific criteria that extends well beyond the 2-meter clause noted in 40 CFR 98.234(a). Commenters stated that this exemption is directly linked to the safety of personnel or the technical use of monitoring equipment. Commenters stated that, specifically, connectors that are ''buried'' or that are ''not able to be accessed at any time in a safe manner to perform monitoring (Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment)'' should not require additional leak detection provisions under subpart W.

Response: Concerning the comment about cross-referencing the NSPS OOOOb alternative standard for natural gas processing plants, we updated the cross references in the subpart W final rule to the NSPS OOOOb to include 40 CFR 60.5401b for natural gas processing in 40 CFR 98.232(d)(7), 98.233(q)(1)(v), 98.233(q)(1)(vii)(F), and 98.236(q)(1)(iv)(D). These revisions add clarity to the subpart W equipment leak provisions.

Concerning the comments on the inaccessible component exemption, we note that this language is not new, it was moved from 40 CFR 98.234(a)(2) to proposed 40 CFR 98.234(a) during reorganization of the rule at proposal. Additionally, as described in the preamble to our 2023 proposed rule, our intent is to align requirements between subpart W and the NSPS OOOOb and EG OOOOc, as appropriate. As noted by the commenter, the term ''inaccessible'' in the NSPS OOOOb and the EG OOOOc is limited to connectors and the term is only found in the context of complying with the alternative standard in 40 CFR 60.5401b(h)(3) and 60.5401c(h)(3), respectively. The NSPS OOOOb and EG OOOOc provide an exemption from the monitoring, leak repair, recordkeeping and reporting requirements for ''inaccessible'' connectors. Consistent with this exemption in the NSPS OOOOb and EG OOOOc, we are providing the same exemption for ''inaccessible'' components in 40 CFR 98.233(q)(1)(vii)(F) for onshore natural gas processing facilities. The term ''difficult-to-monitor,'' however, is included in the NSPS OOOOb and EG OOOOc specifically when using EPA Method 21 screening method and is characterized in the NSPS OOOOb and EG OOOOc as being for components that would require elevating the monitoring personnel more than 2 meters above a support surface. Therefore, we agree with commenters that we intended the term ''inaccessible'' to have the same meaning as the term ''difficult-to-monitor'' as provided in the NSPS OOOOb and EG OOOOc and we are therefore replacing the term ''inaccessible'' with the term ''difficult-to-monitor'' in 40 CFR 98.233(q)(1)(vii)(F) and 98.234(a).

Comment: Commenters encouraged the EPA to promote the use of alternative technologies for leak detection. Several commenters stated that the EPA should allow the use of technologies approved under the NSPS OOOOb and 40 CFR part 62 state plans advanced technology framework for quantification of equipment leak emissions under subpart W and/or develop a subpart W-specific framework for approval of alternate technologies for equipment leak emissions quantification.

Response: The EPA acknowledges comments requesting that the Agency promote the use of alternative technologies to detect leaks. The EPA is doing so to the extent it is appropriate in the context of subpart W in certain aspects of this final rulemaking. The EPA is aware of various technologies including fixed sensor monitors, UAVs or drones, aircraft, and satellites currently in use and deployed for various oil and gas survey purposes, as well as those in development. The EPA does not dispute the availability and capabilities of these newer developing technologies as alternative and supplements to standard leak detection technologies. However, as the commenters also indicate, there are several ongoing remote sensing activities to improve the understanding of how such advanced detection technologies work, and there is still much to learn on how data from remote sensing can be applied for emissions quantification. As discussed in the preamble to the final rule, we are not finalizing a framework for the adoption of advanced survey or measurement methane technology analogous to the performance-based technology approval process included in the NSPS OOOOb at 40 CFR 60.5398b(d).

Under the ''Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After December 6, 2022,'' published on March 8, 2024 (89 FR 16820), the EPA finalized provisions to allow entities seeking to utilize the alternative compliance options under 40 CFR 60.5398b(b) (periodic screening alternative) and 60.5398b(c) (continuous monitoring alternative), in lieu of complying with the fugitive emissions standards under 40 CFR 60.5397b. In order to use the alternative compliance options of 40 CFR 60.5398b(b) and (c), entities must meet certain qualifications and must use advanced methane detection technology that has been approved by the EPA. In the final NSPS OOOOb at 40 CFR 60.5398b(d), the EPA provided specific detailed provisions that entities seeking to use technologies other than AVO, OGI and Method 21 must provide to the Agency in order to apply for specific alternative test method approval.

The final alternative test method provisions under NSPS OOOOb were specifically developed for the use of the advanced methane detection technology in lieu of the required fugitive emissions monitoring methods in the rule, and implements specific criteria for the review, evaluation, and potential use of advanced methane detection technology specifically for use in periodic screening, continuous monitoring, and/or super-emitter detection. The adoption of an alternative technology pathway under final NSPS for the oil and natural gas sector was primarily aimed at detecting fugitive emissions from well sites, centralized production facilities and compressor stations and to repair those confirmed detections as quickly as possible. Agency approved alternative technologies would be permitted to be used under NSPS OOOOb and EG OOOOc to find and identify leaks and repair confirmed detected sources of emissions.

As described above, the focus of NSPS OOOOb and EG OOOOc is to find and repair leaks as quickly as possible in order to minimize emissions, and there is no requirement to quantify emissions. The EPA lacks specific information at this time in order to establish an alternative technology framework for subpart W analogous to that finalized for the NSPS OOOOb for fugitive emissions that the Agency believes would be appropriate to quantify and report emissions under subpart W. In order to quantify emissions from leaks identified using one of the alternative periodic screening approaches in the finalized NSPS OOOOb, we would need to have data collected using these screening methods compared to data collected with OGI or EPA Method 21 (or other appropriate data to quantitatively assess how the detected and quantified emissions compare to total actual emissions from equipment leaks) in order to develop appropriate leaker factors. As discussed in the preamble in section III.P.1. of this preamble, different screening approaches for leak detection result in the identification of different subsets of total leaks at a facility, due to the limitations of each screening approach. In order to develop accurate leaker factors or allow direct quantification of leak emission rates, the EPA would need data to understand the population of both detected and undetected leaks specific to the screening approach and associated detection limit.

For these reasons and based on the additional discussion on this topic in section II.B. of this preamble, the EPA believes that a notice-and-comment rulemaking would be necessary to properly and adequately consider the adoption of the alternative technology framework in NSPS OOOOb that would be applicable and appropriate for subpart W purposes. In advance of such a rulemaking, the EPA intends to solicit input on the use of advanced measurement data and methods in subpart W through a white paper, workshop or request for information.

7. Exemption for Components in Vacuum Service

Through correspondence with the EPA via e-GGRT, some reporters have stated that certain equipment leak components at their facility are in vacuum service. These reporters indicated that there are no fugitive emissions expected from components in vacuum service. After consideration of these comments and in order to be consistent with other EPA equipment leak regulatory programs (*e.g.,* 40 CFR part 60, subpart VVa), we have determined that we agree with commenters. For these reasons, we are finalizing as proposed an exemption in the introductory paragraphs of 40 CFR 98.233(q) and (r) for leak components in vacuum service from the requirement to estimate and report emissions from these components. We are also finalizing as proposed a definition in 40 CFR 98.238 for the term ''in vacuum service.'' We are finalizing as proposed to require the reporting of the count of equipment in vacuum service to enable verification of the reported data (*i.e.,* ability to confirm that all equipment for which emissions are expected has been accounted for and an indication that other equipment has been confirmed to meet the proposed definition of ''in vacuum service''). The EPA received only supportive comments regarding these amendments. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

Q. Equipment Leaks by Population Count

As noted in section III.P. of this preamble, subpart W reporters are currently 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.,* existing table W–1A to subpart W 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 currently 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 existing tables W–1B and W–1C, as applicable. Reporters in other industry segments currently must count each applicable component at the facility.

We are finalizing, as proposed, 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.B. and II.C. of this preamble. Consistent with the 2023 Subpart W Proposal, the key changes included in this final rule are providing updated population count emission factors based on recent peer reviewed studies for: major equipment at Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities; below grade stations, pipeline mains, and pipeline services at natural gas distribution facilities; and gathering pipelines at Onshore Petroleum and Natural Gas Gathering and Boosting facilities.

1. Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting Population Count Method

The EPA is finalizing several revisions related to equipment leaks by population count for equipment at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities as described in this section. The EPA received only minor comments regarding these revisions. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

The existing 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 existing table W–1A to subpart W. The gas service population emission factors are based on the 1996 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–2023–0234). The oil service population emission factors are based on the API's Emission Factors for Oil 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 currently under the existing provisions 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 existing 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.

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. Based on our review of these studies, our assessment is that they support revision of the population count method and corresponding emission factors for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, and we are finalizing as proposed amendments to this population count method and corresponding emission factors after consideration of these more recent study data, consistent with section II.B. of this preamble. These final 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 will eliminate the step to estimate the number of components. All facilities will be able to count the actual number of major equipment and consistently apply the same emission factor to calculate emissions. This will 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.

In comparing the recent study data for the 2023 Subpart W proposal and this final rule, we concluded that the Rutherford *et al.* (2021) study represents the most robust sample size of approximately 3,700 measurements for developing population emission factors by major equipment. The larger sample size is likely more representative of varying degrees of leak detection and repair programs (*i.e.,* not only facilities conducting frequent surveys), which can impact the number of leaks found during surveys (*i.e.,* if more frequent surveys are being conducted and leaks are being repaired in a timely manner, then each survey likely finds less leaks). The Rutherford *et al.* (2021) study also employs a bootstrap resampling statistical approach [72] that allows for the inclusion of infrequent large equipment leaks in the development of the emission factors, improving the representation of the inherent variability of equipment leaks in the developed emission factors. Therefore, we are finalizing as proposed major equipment emission factors developed using Rutherford *et al.* (2021) to provide population emission factors by major equipment and site type (*i.e.,* natural gas system or petroleum system). The final emission factors were taken from Supplementary Tables 3 and 4 of Rutherford *et al.* (2021). The average emission factors presented in these study tables were converted from units of kilograms per day to standard cubic feet of whole gas per hour for cumulative equipment component leaks from different types of major equipment including wellheads, separators, heaters, meters including headers, compressors, dehydrators and tanks. The major equipment indicating venting emissions (*e.g.,* tanks—unintentional vents) or emissions from other sources also covered by subpart W (*e.g.,* liquids unloading, flaring, pumps) are not included in the final equipment leak population emission factors. Consistent with current requirements related to meters/piping at existing 40 CFR 98.233(r)(2)(i)(A), we are finalizing in 40 CFR 98.233(r)(2) 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 study data that inform Rutherford *et al.* (2021), the final emission factors in final table W–1 to subpart W include more pieces of major equipment than are currently included in table W–1B and W–1C to subpart W. A complete description of the derivation of the final 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–2023–0234. The final major equipment emission factors will replace the current component-based emission factors in the existing table W–1A. We are also finalizing removal, as proposed, of tables W–1B, W–1C, and W–1D since they will no longer be needed for the population count method for these industry segments. We are finalizing amendments, as proposed, to the reporting requirements for the use of the population count method to align with the reporting of major equipment counts consistent with the final emission factors in 40 CFR 98.236(r).

2. Natural Gas Distribution Emission Factors

The EPA is finalizing several revisions related to equipment leaks by population count for equipment at natural gas distribution facilities as described in this section. The EPA received only minor comments regarding these revisions. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

Natural gas distribution companies currently under the existing provisions 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 existing table W–7 (final table W–5) to subpart W, and operating time to estimate emissions. The population emission factors for distribution mains and services in existing table W–7 (final table W–5) are based on information from the 1996 GRI/EPA study.[73] Specifically for plastic mains, additional data are sourced from a 2005 ICF analysis.[74] The population emission factors for distribution mains are published per mile of main by pipeline material and emission factors for distribution services are published per service by pipeline material. The population emission factors for below grade stations in existing table W–7 (final table W–5) are based on information from the 1996 GRI/EPA study.[75] The population emission

[72] Bootstrapping is a type of resampling where a known dataset is repeatedly drawn from, with replacement, to generate a sample distribution.

[73] 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–2023–0234.

[74] 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–2023–0234.

[75] 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

factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations are currently specified in the existing table W–7 per station by three inlet pressure categories (>300 pounds per square inch gauge (psig), 100–300 psig, <100 psig).

In this rulemaking, the EPA is finalizing as proposed to update the population emission factors in existing table W–7 (final table W–5) 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.[76] The majority of the U.S. GHG Inventory updates were based on data published by Lamb *et al.* in 2015.[77] 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 including Weller *et al.* in 2020.[78] 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.

The population emission factors for distribution mains and services are a function of the average measured leak rate (in standard cubic feet per hour) 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 1996 GRI/EPA study. The Weller *et al.* study quantified leaks from only distribution mains using the Advanced Mobile Leak Detection (AMLD) technique, which involved mobile surveying using high sensitivity instruments and algorithms that predicted 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.

In the 2022 proposed rule, we proposed to revise the pipeline main equipment leak emission factors using a combination of data from Lamb *et al.* (2015) and Weller *et al.* (2020). We sought comment on the approach of combining data from these two studies. We received numerous comments regarding the classification of pipeline materials and respective quantified leaks in the Weller *et al.* (2020) study. As discussed in more detail below, we agreed with commenters on the 2022 proposed rule that the categorization of pipeline leaks by material type likely resulted in inaccuracies specifically for the unprotected and protected steel pipeline material types. Therefore, in this rulemaking, we are finalizing as proposed in the 2023 Subpart W Proposal revisions of the equipment leak pipeline main emission factors using more recent study data from the Lamb *et al.* (2015) study.

In subpart W, there are currently four categories of pipeline mains: unprotected steel, protected steel, plastic, and cast iron. The steel categories are differentiated by the presence of cathodic protection, and, as evidenced by the 1996 GRI/EPA study and Lamb *et al.* study data, unprotected steel pipelines are considered to be more leak prone than cathodically protected steel pipelines. In the Weller *et al.* study, the categories of pipeline mains include bare (unprotected) steel, coated (protected) steel, cast iron, and plastic. We note that steel pipelines can be protected by cathodic protection and/or coating, and in the Weller *et al.* study, cathodically unprotected yet coated steel pipeline mains appear to have been grouped with cathodically protected steel pipeline mains. Using the unprotected and protected steel classifications in the Weller *et al.* study would thus result in emission factors for protected steel that are higher than for unprotected steel, which would conflict with other study data (*e.g.,* 1996 GRI/EPA, Lamb *et al.*) as well as voluntary emissions reductions programs (*e.g.,* EPA Natural Gas STAR). The pipeline categories in the Weller *et al.* study do not provide the necessary differentiation to be used to properly update the emission factors for unprotected (*i.e.,* not cathodically protected) steel and cathodically protected steel pipeline mains. For more information on the review and analysis of the Lamb *et al.* and Weller *et al.* studies, see the subpart W TSD, available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

In consideration of our review and analysis of recent study data relative to natural gas pipeline mains and services, and consistent with the emission factors used in the 2016 U.S. GHG Inventory, we are finalizing as proposed in the 2023 Subpart W Proposal to provide emission factors for distribution pipeline mains and services based on the Lamb *et al.* study leak rates and the 1996 GRI/EPA study leak incidence data. For more information on the derivation of the final emission factors, see the subpart W TSD, available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

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 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–2023–0234). 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 finalizing as proposed to amend the emission factors for below grade transmission-distribution transfer stations and below grade metering-regulating stations in existing table W–7 (final table W–5) to

---

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–2023–0234.

[76] 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–2023–0234.

[77] 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–2023–0234.

[78] 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–2023–0234.

subpart W to a single emission factor without regard to inlet pressure. We are also finalizing as proposed to amend the corresponding section header in existing table W–7 (final table W–5) for below grade station emission factors and the references to existing table W–7 (proposed table W–5) 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 final amendment will impact the reporting requirements in 40 CFR 98.236(r) as well, as it will 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). Consistent with section II.B. of this preamble, this final amendment will 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 will also result in reporting of fewer data elements, consistent with section II.C. of this preamble.

3. Gathering Pipeline Emission Factors

a. Summary of Final Amendments

Facilities in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment currently under existing provisions 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 existing table W–1A to subpart W, and operating time to estimate emissions. The population emission factors for gathering pipelines in existing 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.[79] The population emission factors for gathering pipelines are published per mile by pipeline material.

As noted in section III.Q.2. of this preamble, the EPA is finalizing as proposed the update to the natural gas distribution population emission factors in existing table W–7 (final table W–5) 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 finalizing as proposed the update to the leak rate portion of the emission factor based on data published by Lamb *et al.* in 2015.[80] The EPA has reviewed the recent studies published for Onshore petroleum and natural gas gathering and boosting facilities including the Yu *et al.* study in the 2023 Subpart W Proposal, as well as additional studies identified in public comments, and concluded that there is currently insufficient data to update the existing emission factors with nationally representative population emission factors for gathering pipelines that are based on collection of data from gathering pipelines rather than distribution pipelines. Therefore, consistent with the updates to the emission factors for distribution mains, and consistent with section II.B. of this preamble, we are finalizing as proposed the update to the gathering pipeline population emission factors in proposed table W–1 to use the leak rates from Lamb *et al.* (2015). We did not propose and are not finalizing updates to 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 as well as responses to comments we received on the updates to the gathering pipeline population emission factors, see section 12 of the subpart W TSD and section 18.3 of the *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule,* available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments for gathering pipelines.

Comment: Commenters asked that the EPA provide operators with the option to use monitoring and measurement surveys to quantify gathering pipeline leak emissions.

Response: See the EPA's response to comments in section III.C.1.b. of this preamble requesting that the EPA allow a leaker emission factor approach and/or direct measurement of transmission pipeline leak emissions, which is also applicable to gathering pipelines and responsive to this comment.

R. Offshore Production

1. Summary of Final Amendments

Currently, subpart W requires offshore production facilities to report emissions consistent with the methods published by the U.S. Department of Interior, Bureau of Ocean Energy Management (BOEM). Since subpart W was first promulgated, there have been a number of updates to the BOEM requirements and how BOEM implements the requirements (*e.g.,* the development of their Outer Continental Shelf Air Quality System (OCS AQS)[81]), and the EPA is finalizing amendments to subpart W to reflect those changes. Specifically, the EPA is finalizing as proposed the update of the outdated acronym ''BOEMRE'' to the current acronym ''BOEM'' in 40 CFR 98.232(b), 40 CFR 98.233(s), and 40 CFR 98.236(s); the update of the cross references to the BOEM requirements from ''30 CFR 250.302 through 304'' to ''30 CFR 550.302 through 304'' in 40 CFR 98.232(b), 40 CFR 98.233(s), and the introductory paragraph of 40 CFR 98.234; and the removal of the outdated references to ''GOADS'' from 40 CFR 98.233(s). The EPA is also finalizing as proposed the adjustments of some of the language in 40 CFR 98.232(b) and 40 CFR 98.233(s) to more accurately reflect the current BOEM program and requirements (*e.g.,* adjusting the number of years between BOEM data collection efforts from 4 to 3 years, referring to a published emissions inventory rather than an emissions study).

Emissions data are collected by BOEM every few years. In years that coincide with a year in which BOEM collects data, offshore production facilities that report emissions inventory data to BOEM report the same annual emissions to subpart W as calculated and reported to BOEM (existing 40 CFR 98.233(s)(1)) and facilities that do not report emissions inventory data to BOEM must use the most recent monitoring and calculation methods published by BOEM (existing 40 CFR 98.233(s)(2)). In the intervening years, reporters currently are required to adjust emissions based on the operating time

[79] 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–2023–0234.

[80] 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–2023–0234.

[81] For more information on this system and the emissions inventories collected by the system, see *https://www.boem.gov/environment/environmental-studies/ocs-emissions-inventories.*

for the facility in the current reporting year relative to the operating time in the most recent BOEM data submission or BOEM emissions study publication year. The EPA finalizing revisions to these calculation methods based on consideration of public comments. The EPA is finalizing a requirement in 40 CFR 98.233(s)(1)(i) that if the BOEM's emissions reporting system is available and the facility has the data needed to use BOEM's emissions reporting system, reporters must calculate emissions using the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 (currently implemented through the OCS AQS). This includes years in which offshore production facilities are required to report emissions inventory data to BOEM as well as intervening years. In the final amendments, the current adjustment using operating hours in years that do not overlap with the most recent published BOEM emissions inventory or BOEM data submission, as app'icable, will only be allowed if the BOEM's emissions reporting system is not available or if the facility 'oes not have the data needed to use BOEM's emissions reporting system (which may be the case in years in which offshore production facilities are not required to report emissions inventory data to BOEM). The EPA is finalizing parallel requirements in 40 CFR 98.233(s)(2)(i) for facilities that do not report to BOEM's emissions inventory except that these requirements refer only to the calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 because these facilities do not currently have access to the OCS AQS system. The 2023 Subpart W Proposal would have maintained the method of adjusting emissions using operating hours as the primary method and provided use of BOEM's monitoring and calculation methods as an alternative, but this final amendment will further improve data quality through the use of more empirical data, consistent with section II.B. of this preamble. The EPA is also amending 40 CFR 98.233(s)(3) to clarify the requirement that offshore production reporters must calculate emissions using BOEM's methods at least once every 3 years. The current rule provides provisions for delays in BOEM's data collection effort beyond 4 years, and the EPA is revising that language to specify requirements for calculation if BOEM's emissions reporting system is unavailable for more than 3 consecutive years, consistent with the updated language in 40 CFR 98.233(s)(1)(i) and (s)(2)(i).

The EPA is also finalizing changes to the reporting requirements in 40 CFR 98.236. First, to improve the verification of the emissions reported by offshore production facilities to the GHGRP by establishing a definitive crosswalk between the data submitted to BOEM's Outer Continental Shelf Emissions Inventory and the GHGRP, the EPA is finalizing as proposed the requirement that offshore production facilities report the BOEM Facility ID(s) that constitute the GHGRP facility. Having a definitive point of reference between the two datasets will allow the EPA to better verify the emissions reported to the GHGRP. Second, for years in which a reporter does calculate emissions by adjusting emissions using a ratio of operating hours, the EPA is finalizing as proposed the requirement to report the facility's operating hours in the current year in 40 CFR 98.236(s)(2)(ii). The EPA is finalizing the other proposed data element, 40 CFR 98.236(s)(2)(i), with slight wording changes from proposal that reflect the final calculation methods described in the previous paragraph. Specifically, the reporter will report the facility's operating hours for the most recent year in which emissions were calculated according to either 40 CFR 98.233(s)(1)(ii) or 40 CFR 98.233(s)(2)(ii). This information will improve verification, consistent with section II.C. of this preamble. For clarification, the EPA is also finalizing a change from proposal to update 40 CFR 98.232(b) to state that offshore platforms do not need to report emissions from portable equipment, in place of the existing language that offshore platforms do not need to report portable emissions.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments for offshore production emissions.

Comment: Commenters suggested that instead of allowing reporters to calculate their emissions each year using BOEM's methods as an alternative to the current requirement to adjust emissions based on operating hours, the EPA should require offshore production facilities to calculate their emissions each year using BOEM's methods. While commenters expressed concern that BOEM's methods are not well-documented and currently rely mostly on emission factors, they did note that BOEM is working to incorporate additional information such as top-down data into their calculation methods, and requiring reporters to use those methods every year would at least ensure that updates to BOEM's methods are incorporated into subpart W as soon as possible. Commenters also stated that requiring use of BOEM's methods every year instead of allowing that as an option would prevent reporters from choosing the option that they predict would result in less emissions.

Response: The EPA has considered these comments and reviewed additional information available about BOEM's OCS AQS. We agree that directing reporters to use BOEM methods to calculate emissions every year as the primary calculation method is consistent with the directives in CAA section 136(h), including ensuring accuracy in total emissions reported for each reporting year. The final amendments to 40 CFR 98.233(s)(1)(i) and (s)(2)(i) require reporters to use BOEM's emission inventory system or calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate emissions for any year in which the system is available and they have collected the necessary data to do so, including years in which facilities report emissions directly to BOEM. The final revisions allow adjustments made based on operating time as an alternative method to adjust emissions; however, the EPA is finalizing revisions to 40 CFR 98.233(s)(3) to require that facilities calculate emissions based on BOEM's calculation methods at least every 3 years.

Comment: One commenter requested that the EPA add ''fugitive sources'' after ''equipment leaks'' in 40 CFR 98.232(b) for consistency with the BOEM's descriptions of emission source types.

Response: The EPA has reviewed BOEM's documentation and agrees that BOEM uses the term ''fugitives'' to refer to leaks from equipment components (generally referred to as ''equipment leaks'' in subpart W). The EPA has added the parenthetical ''(*i.e.,* fugitives)'' to both 40 CFR 98.232(b) and 40 CFR 98.233(s) introductory text.

S. Combustion Equipment

1. Calculation Methodology Applicability, Higher Heating Value, and Other Calculation Methodology Clarifications

a. Summary of Final Amendments

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). Subpart W refers reporters in these segments to the calculation methodologies in subpart C to determine combustion emissions for certain fuels.

The EPA is finalizing several amendments for the industry segments that report combustion equipment emissions under subpart W to improve the accuracy of the emissions calculated and therefore the quality of data collected, consistent with section II.B. of this preamble. First, we are finalizing as proposed the move of 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). Second, we are finalizing as proposed the move of the language in 40 CFR 98.233(z)(1)(ii) to 40 CFR 98.233(z)(5), and we are finalizing the proposed wording changes to highlight that this paragraph refers only to the requirement to report combustion emissions under subpart W. We are also finalizing as proposed the addition of a reference to this new paragraph 40 CFR 98.233(z)(5) in both 40 CFR 98.233(z)(1)(ii) and 98.233(z)(2)(ii). Third, the EPA is revising 40 CFR 98.233(z)(1) as proposed 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 is also finalizing as proposed conforming edits to existing 40 CFR 98.233(z)(2) (final 40 CFR 98.233(z)(3)) for consistency. Fourth, as proposed, the EPA is finalizing the revision to the language in existing 40 CFR 98.233(z)(2)(ii) (final 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 each constituent in the flow of gas to the unit, which 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. Fifth, we are finalizing as proposed the amendment of the definition of the variable for the HHV in equation W–40 in 40 CFR 98.233(z)(3)(ii) to require the use of a site-specific value.

As explained in the 2023 Subpart W Proposal, the EPA proposed several revisions to address stakeholder requests to expand the ability to use subpart C calculation methodologies to additional fuel types and to improve the accuracy of the emissions calculated and therefore the quality of data collected, consistent with section II.B. of this preamble. Specifically, the EPA proposed to specify in a new paragraph in 40 CFR 98.233(z)(2) that subpart C methodologies Tier 2, Tier 3, or Tier 4 may be used to calculate emissions from the combustion of a fuel that meets the definition of ''natural gas'' in 40 CFR 98.238 if it has a minimum HHV of 950 Btu/scf, a maximum CO2 content of 1 percent by volume, and a minimum CH_4 content of 85 percent by volume. We also requested comment on whether additional specification criteria should be included (e.g., a maximum HHV). After consideration of public comment, we updated our analysis of fuel compositions and our re-analysis of the data showed that maintaining the minimum HHV at 950 Btu/scf, limiting the maximum HHV to 1,100 Btu/scf, and decreasing the minimum CH_4 content to 70 percent by volume resulted in a data set for which emissions under both subpart C (Tier 2) and subpart W were more consistently similar than the proposed parameters of maximum CO_2 content of 1 percent by volume and a minimum CH_4 content of 85 percent by volume. Therefore, we are finalizing in 40 CFR 98.233(z)(2) that subpart C methodologies Tier 2, Tier 3 or Tier 4 may be used to calculate emissions from the combustion of a fuel that meets the definition of ''natural gas'' in 40 CFR 98.238 if it has a minimum HHV of 950 Btu/scf, a maximum HHV of 1,100 Btu/scf, and a minimum CH_4 content of 70 percent by volume.

Finally, we are finalizing two amendments to provide clarity and improve understanding of the final rule, consistent with section II.D. of this preamble. We are finalizing as proposed the amendments to 40 CFR 98.233(z)(1)(ii) and existing 40 CFR 98.233(z)(2) (final 40 CFR 98.233(z)(3)(ii)) and finalizing analogous language in 40 CFR 98.233(z)(2)(ii) to clarify that emissions may be calculated for either each individual unit or groups of combustion units combusting the same fuel. In addition, based on consideration of public comments and for consistency with other paragraphs for specific emission source types, we are amending the name of 40 CFR 98.233(z) and 40 CFR 98.236(z) to remove the specific industry segment names and refer just to combustion equipment.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to calculation methodology applicability, HHV, and other calculation methodology clarifications (not including revisions related to methane slip).

Comment: Commenters requested that the EPA define ''pipeline quality natural gas.'' Commenters also asserted that the composition requirements in proposed 40 CFR 98.233(z)(2)(i)(B) and (C) were not justified and limited the combustion devices that would be able to use the combustion methodologies in subpart C, which would in turn limit the combustion devices that would be able to use performance test data or manufacturer provided data to calculate emissions that include methane slip.

Response: The EPA reviewed the comments, including the various suggested definitions of ''pipeline quality natural gas,'' and reviewed the analysis supporting the proposed compositions in 40 CFR 98.233(z)(2)(i)(B) and (C). First, the commenters varied in their suggested definitions, identifying two different definitions of ''pipeline quality natural gas'' from EPA regulations and also suggesting other provisions that they asserted are considered accepted or understood definitions of ''pipeline quality natural gas.'' These variations support the EPA's assertion from the 2023 Subpart W proposal that pipeline quality specifications vary across the U.S. depending on the requirements of the pipeline used to transport the gas. Therefore, the EPA is not finalizing a definition of ''pipeline quality natural gas'' for subpart W.

However, most of the specifications for pipeline quality natural gas did include a maximum HHV and a minimum CH_4 content of 70 percent, which was lower than the proposed minimum CH_4 content of 85 percent. The EPA did not propose to include a maximum higher heating value in 40 CFR 98.233(z)(2)(i), but the EPA did request comment on additional parameters that should be considered. When reviewing the data to assess the effect of the HHV, the EPA concluded that maintaining the minimum HHV at 950 Btu/scf, limiting the maximum HHV to 1,100 Btu/scf, and decreasing the minimum CH_4 content to 70 percent by volume resulted in a data set for which emissions under both subpart C (Tier 2) and subpart W were more consistently similar than the proposed parameters of maximum CO_2 content of 1 percent by volume and a minimum CH_4 content of 85 percent by volume. The constituents other than CH_4 and CO_2 in the natural gas stream include compounds that have no heating value, such as hydrogen and nitrogen, as well as non-methane hydrocarbons and NGLs (*e.g.,* ethane, propane, butane). The more NGLs in the stream, the more the emissions under the subpart C (Tier 2) calculations differ from the subpart W calculations, and limiting the maximum HHV reduces the number of streams with high quantities of NGLs that could use subpart C (Tier 2) methods without needing to restrict the CO_2 content. For more information on our revised fuel composition analysis for the final rule and the comparison of emissions using various composition thresholds, see the final subpart W TSD, available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

As a result of this analysis, we are finalizing in 40 CFR 98.233(z)(2) 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 HHV of 1,100 Btu/scf, and a minimum CH_4 content of 70 percent by volume. These specifications may in many cases be the same as the specifications for pipeline quality natural gas, but including these specifications in a separate paragraph of 40 CFR 98.233(z) maintains the flexibility to use subpart C methods both in cases where a local definition of pipeline quality natural gas might not be exactly the same as these specifications (*e.g.,* might have a slightly larger maximum heat content) and in cases where a local definition of pipeline quality natural gas is more restrictive than these specifications.

Revisions to the proposed provisions for combustion slip are addressed in section III.S.2. of this preamble.

Comment: One commenter suggested that the EPA should update the name of 40 CFR 93.233(z) and remove the references to the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments because the proposed provisions for combustion slip apply to all industry segments that must report combustion emissions.

Response: The EPA has reviewed this comment and is amending the name of 40 CFR 98.233(z) and 40 CFR 98.236(z) to remove the references to specific industry segments. The lists in 40 CFR 98.232 define which emission sources must be included in reports for each industry segment, so it is unnecessary and duplicative to include industry segment names in the emission source type paragraph names. This final amendment is also consistent with other changes to emission source type names, such as hydrocarbon liquids and produced water storage tanks in 40 CFR 98.233(j). The EPA notes that 40 CFR 98.232, specifically 40 CFR 98.232(c)(22), (i)(7), and (j)(12), continues to specify the industry segments that must calculate emissions according to 40 CFR 98.233(z) and report emissions under 40 CFR 98.236(z); this name change does not mean that additional industry segments will report combustion equipment emissions under 40 CFR 98.236(z) than under the existing requirements. The EPA is finalizing amendments to subpart C to implement revisions to account for methane slip from combustion devices in industry segments that report combustion emissions under subpart C, as described in section III.S.2. of this preamble. While those amendments cross-reference 40 CFR 98.233(z)(4), that does not make the combustion devices in industry segments that report combustion emissions under subpart C subject to 40 CFR 98.233(z) in its entirety, nor do cross-references to subpart C from 40 CFR 98.233(z)(1) and (2) make combustion equipment in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments subject to subpart C.

2. Methane Slip From Internal Combustion Equipment

a. Summary of Final Amendments

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 CH_4 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 accurately account for combustion slip. 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–2023–0234).

Consistent with section II.A. of this preamble, we are revising the methodologies for determining combustion emissions from RICE and GT to account for combustion slip. For the three subpart W industry segments reporting combustion emissions under subpart W (Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution), we are finalizing as proposed that RICE and GT units combusting natural gas that calculate emissions using the subpart C calculation methodologies per 40 CFR 98.233(z)(1) and 98.233(z)(2) have three options in 40 CFR 98.233(z)(4) to quantify emissions from combustion slip, including direct measurement using a performance test, the use of OEM data, or the use of default emission factors. For facilities that conduct a performance test to calculate combustion slip under 40 CFR 98.233(z)(4)(i), the performance test must be completed in accordance with one of the test methods in 40 CFR 98.234(i), which include EPA Methods 18 and 320 as well as an alternate method, ASTM D6348–12 (Reapproved 2020), *Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy*, Approved December 1, 2020. After consideration of public comments, we are finalizing Method 25A with nonmethane cutter as described in 40 CFR 1065.265 (as specified in table 2 of 40 CFR part 60, subpart JJJJ) as an additional test method for use in performance testing. The results of the performance test must be used to develop an emission factor for use in the CH_4 emissions calculation. If a facility is required (for compliance with other EPA regulations) or elects to conduct a performance test for any reason (*e.g.,* to demonstrate compliance with permit conditions, assess equipment performance), they must use the results of the performance test to calculate methane slip emissions. When multiple performance tests are completed in the same reporting year, the arithmetic average of all emission factors for the corresponding performance tests must be used in CH_4 emissions calculation. For facilities that did not conduct a performance test for any reason and elect to use OEM data, which may include manufacturer specification sheets, emissions certification data, or other manufacturer data providing expected emission rates from the RICE or GT, we are finalizing as proposed that the reporter use the OEM data to develop an emission factor for use in their emissions calculations for CH_4. For facilities that did not conduct a performance test for any reason and elect to the use the final default emission factors, which the EPA developed using data from Zimmerle *et al.* (2019), we are requiring the reporter to select the appropriate emission factor by equipment type (*e.g.,* 2-stroke lean-burn, 4-stroke lean-burn, 4-stroke rich-burn, or GT) in new table W–7 rather than the emission factors in table C–2 for use in their emissions calculations for CH_4.

We proposed not to allow performance testing for facilities operating RICE and GT units combusting fuels that fall under 40 CFR 98.233(z)(3) due to variability in fuel composition. Stakeholders provided quarterly compressor station gas composition for units combusting fuels that fall under all categories described in 40 CFR 98.233. In general, we observed fuel compositions that fell under 40 CFR 98.233(z)(3) did not significantly vary more than fuels that fell under 40 CFR 98.233(z)(2), therefore we are adding performance testing as another option under 40 CFR 98.233(z)(3)(ii)(C) to determine CH_4 emissions. Previously, for fuels under 40 CFR 98.233(z)(3), CH_4 emissions could only be determined using a default equipment-specific combustion efficiency, provided in equations W–39A and W–39B and combined with fuel composition to calculate emissions. The second option being added for fuels under 40 CFR 98.233(z)(3) is based on direct measurement using a performance test in accordance with one of the test methods in 40 CFR 98.234(i), the same as the first option provided for natural gas that meets the specifications in either 40 CFR 98.233(z)(1) or (z)(2).

We expect that the records necessary to confirm the value for the development of an emission factor based on the results of a performance test or OEM data are already required to be maintained by the facility per 40 CFR 98.237; thus, no new recordkeeping provisions relative to the combustion slip amendments are being finalized. The EPA is finalizing a new reporting requirement in 40 CFR 98.236(z)(2) specifically for RICE and GT that combust natural gas that meets the criteria of 40 CFR 98.233(z)(1) or (2) or a fuel meeting the specifications of 40 CFR 98.233(z)(3) to specify the equipment type of reported internal combustion units, the method used to estimate the CH_4 emission factor, and the value of the emission factor to facilitate verification of the reported emissions. This amendment requires the reporting of CH_4 emissions from natural gas-fired internal combustion engine and GT units, that are grouped for reporting, must share the same equipment type (*e.g.,* 4-stroke rich burn), fuel type, and method for determining the CH_4 emission factor, which will allow the EPA to adequately verify the data.

Additionally, we are finalizing as proposed that RICE or GT units in subpart W industry segments (*i.e.,* Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution) that estimate and report their combustion emissions to subpart C and currently use either equation C–8, C–8a, C–8b, C–9, C–9a, or C–10 in 40 CFR 98.33(c), as it corresponds to the Tier methodology selected to estimate their CO_2 emissions, are required to use one of the options in 40 CFR 98.233(z)(4) to develop a CH_4 emission factor for use in these equations to estimate CH_4 emissions. Specifically, we are finalizing as proposed the revision to 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 options for developing a CH_4 emission factor in 40 CFR 98.233(z)(4) for natural gas-fired RICE or GT. We are also finalizing as proposed a footnote to table C–2 that specifies that for reporters subject to subpart W, the default CH_4 emission factor in table C–2 for natural gas may only be used for natural gas-fired combustion units that are not RICE or GT.

Finally, we are finalizing as proposed to amend 40 CFR 98.36(b), (c)(1), and (c)(3) specifically for RICE or GT at facilities that are subject to subpart W. These provisions currently provide the requirements for reporting by emission unit, by aggregation of units or by common pipe configurations. Under the new amendments, we are requiring reporters that report emissions in accordance with 40 CFR 98.36(b), (c)(1), or (c)(3) to provide the equipment type (*e.g.,* 2-stroke lean burn RICE), the method used to determine the CH_4 emission factor and the average value of the CH_4 emission factor. This change will ensure that sufficient data in the overall aggregation of units or common pipe (*i.e.,* multiple units combusting natural gas) is reported such that we can perform review of the supplied emission factor data and perform verification on the corresponding emissions. Overall, these amendments to the subpart C reporting requirements are analogous to and consistent with what is being required for RICE or GT for facilities that report combustion emissions under subpart W.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to methane slip.

Comment: Many commenters agreed methane slip should be extended to all RICE and GTs regardless of application for all subpart W industry segments that currently report combustion emissions in subpart C or W. They acknowledged providing three methods for quantifying slip (default emission factors, direct measurement, and OEM data) for RICE and GT using natural gas outlined in 40 CFR 98.233(z)(1) and (2) increased the accuracy of reported emissions. Several commenters agreed that fuel types covered in proposed 40 CFR 98.233(z)(3) are too variable in composition and emission factors would not be representative of real operating conditions, so these fuel types should be limited to only using default combustion efficiency values. In contrast, multiple commenters suggested that the EPA allow reporters to use performance tests to develop emission factors regardless of fuel type or be able to demonstrate limited fuel variability in fuels not covered in 40 CFR 98.233(z)(1) and (2). Some commenters suggested if the operator voluntarily performs an annual performance test or performance tests required under other federal standards (NSPS Subpart JJJJ or NSPS Subpart KKKK), these results should be allowed to determine combustion slip instead of the proposed one-time performance test. Some commenters stated that, additionally, not allowing performance tests for all RICE and GT, regardless of the composition of the natural gas combusted, will disincentive operators from deploying new emerging technology meant to reduce emissions from this source category. Multiple commenters asked for clarification about the requirements for performance testing and if it was a one-time test or another required frequency.

Response: The EPA acknowledges the commenters' support for including combustion slip from RICE or GT irrespective of their use to drive a compressor or the industry segment in which they operate. We agree developing emission factors from direct measurement and using OEM data for these engines and turbines will help to increase the accuracy of the reported emissions. The EPA did not propose to allow the use of performance testing to RICE or GTs that combust fuels described in 40 CFR 98.233(z)(3) due to the suspected high variability in the fuel composition. However, stakeholders provided quarterly compressor station gas composition data for units combusting fuels that fall under all categories described in 40 CFR 98.233(z). In general, we observed fuel compositions that fell under 40 CFR 98.233(z)(3) did not significantly vary more than fuels that fell under 40 CFR 98.233(z)(2); therefore, for facilities operating RICE and GT units combusting fuels that fall under 40 CFR 98.233(z)(3), we are adding performance testing as another option to determine CH_4 emissions. We are finalizing an amendment to further extend the use of performance testing to fuels that do not meet the natural gas specifications in 40 CFR 98.233(z)(1) or (2), as described in 40 CFR 98.233(z)(3). If a facility combusting a fuel as described in 40 CFR 98.233(z)(3)(i) elects to conduct a performance test in accordance with 40 CFR 98.233(z)(4)(i) for any reason (*i.e.,* assess equipment performance, provide data to meet company emission reduction goals, demonstrate compliance with permits or regulations), the result of this performance test would be required to be used to develop an emission factor and used in equation W–40 of 40 CFR 98.234(z)(3)(ii)(G) to estimate CH_4 emissions, consistent with the approach proposed and finalized for 40 CFR 98.233(z)(2). Additionally, when multiple performance tests are completed in the same reporting year, the arithmetic average of all emission factors for the corresponding performance tests must be used in CH_4 emissions calculation. A facility that has not performed a performance test for any reason must calculate their methane emissions as provided in 40 CFR 98.234(z)(3)(ii)(D) using equipment specific default combustion factors with equation W–39B. We did not include a performance testing frequency for fuels subject to 40 CFR 98.233(z)(3) because of their low compositional variability, which is consistent with what we proposed and are finalizing for fuels subject to 40 CFR 98.233(z)(1) or (2). By further extending the use of direct measurement, reporters have both a measurement and default option for additional fuels used in RICE and GTs, consistent with directives in CAA section 136 and will help incentivize the deployment of new technology meant to reduce emissions. For more information on our evaluation, see the subpart W TSD, available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

Comment: Multiple commenters suggested adding additional test methods for use in performance testing to measure CH_4 concentrations. Some of the commenters recommended adding Method 25A with nonmethane cutter as described in 40 CFR 1065.265 (as specified in table 2 of 40 CFR part 60, subpart JJJJ). Commenters noted the nonmethane cutter test method would allow for continuity in testing procedures currently in place and allowed by both the EPA and state agencies. Commenters stated that, additionally, this method would decrease the burden related to operators having to perform multiple tests to comply with different requirements of subpart W and better align with tests conducted for NSPS JJJJ and NSPS ZZZZ. One commenter recommended adding ASTM 6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy or portable fuel meters and thermodynamic software to determine true horsepower to determine emission factors of methane. The commenter suggested performance testing allows operators to diagnose engine problems, that normally go undetected, resulting in cleaner burning engines with improved performance.

Response: The addition of performance testing for all natural gas fuels combusted in RICE and GT will improve the accuracy for CH_4 emission reporting in the GHGRP and align with the directives in CAA section 136. To further increase flexibility and alignment with other regulatory requirements, the EPA reviewed and is adding Method 25A with Nonmethane cutter as described in 40 CFR 1065.265 to the approved testing methodologies listed in final 40 CFR 98.234(i). The EPA does not agree with including ASTM 6348–03, as it has been superseded by a more recent version. Instead, the alternate method ASTM 6348–12 (Reapproved 2020) is being finalized as an approved testing methodology in 40 CFR 98.234(i). This method is the most current version for the ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy.'' Additionally, the EPA does not agree with allowing thermodynamic software to determine horsepower and subsequently back calculating the CH_4 emission factor. The use of thermodynamic software in this way is useful for diagnosing engine problems but has not been studied for its accuracy for determining CH_4 emissions. The EPA may add additional methods to 40 CFR 98.234(i) in future amendments through a rulemaking process.

3. Location of Reporting Requirements for Combustion Equipment

As noted in section III.S.1. of this preamble, facilities in the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments must calculate combustion emissions in accordance with 40 CFR 98.233(z) and report emissions under existing subpart W. Facilities in the remaining industry segments (*i.e.,* Offshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment) are required to calculate combustion emissions in accordance with the provisions of 40 CFR 98.33 and report emissions under subpart C.

In the 2023 Subpart W Proposal, the EPA requested comment on amending subpart W to specify that all industry segments would be required to report their combustion emissions, including CH_4, under subpart W to more accurately reflect the total CH_4 emissions from such facilities within the emissions reported under subpart W. The EPA received comments supporting the reporting of all combustion emissions under subpart W but also received comments suggesting that the EPA instead should require reporting of all combustion emissions under subpart C, including combustion emissions from the Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Natural Gas Distribution industry segments that are currently reported under subpart W. The EPA evaluated the comments and has decided not to take final action on any of the requested changes to 40 CFR 98.232 regarding which industry segments must report combustion emissions under subpart W.

Section 136(h) of the CAA specifies that the EPA shall ''revise the requirements of subpart W . . . to ensure the reporting under such subpart . . . accurately reflect[s] the total methane emissions and waste emissions from the applicable facilities.'' Sections 136(c) and (e) of the CAA specify that the waste emissions charge provisions apply to emissions reported pursuant to subpart W, and CAA section 136(d) indicates that the term ''applicable facility'' means a facility within an affected industry segment, as defined in subpart W. At the time that Congress drafted CAA section 136, the existing reporting structure in which combustion emissions are reported under subpart C for some industry segments and subpart W for other industry segments was already established. Under CAA section 136(d), the nine affected industry segments are categorized into four groups, and a waste emissions threshold is applied to each of the four. Congress was aware of this reporting struXXXndustryen it enacted CAA section 136 and established the industry segment-specific thresholds. The EPA finds no indication in the text of CAA section 136 suggesting that the thresholds should be applied to an alternative to the existing reporting structure regarding combustion emissions under subpart W.

T. Leak Detection and Measurement Methods

1. 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.B. of this preamble, we are finalizing as proposed 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 finalizing as proposed that a leak is detected if an audible leak signal is observed or registered by the device. Second, we are finalizing as proposed 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 revisions will improve the accuracy of emissions reported for compressors and transmission tanks when an acoustic leak detection device is used. The EPA received only supportive comments regarding the revisions for acoustic leak detection devices. See the document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

2. High Volume Samplers

a. Summary of Final Amendments

We are finalizing as proposed 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.B. of this preamble. First, we are adding detail to 40 CFR 98.234(d)(3) to clarify the calculation methods associated with high volume sampler measurements. Generally, high volume samplers measure CH_4 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 CH_4 flow in either a mass flow or volumetric flow basis. Specifically, we are finalizing as proposed methods to determine natural gas (whole gas) flows based on measured CH_4 flows.

Second, we are finalizing as proposed 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. Considering actual sampling rates, gas collection efficiencies near the sampling rates, and reported CH_4 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 finalizing as proposed the specification that CH_4 flows above the manufacturer's CH_4 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. However, after consideration of public comment, we are providing an allowance for reporters that use OGI to ensure that there is 100 percent capture of the leak emissions during the entire high volume sampling period to be able to use the measured flow rate even where it exceeds 70 percent of the manufacturer's maximum sampling rate. If emissions are observed escaping capture from the high volume sampler when using OGI to ensure capture, then that measurement is considered invalid (*i.e.,* considered to be exceeding the quantitation capacity of the device) even if the measured flow rate is less than 70 percent of the sampling rate. For more information on our review, see the subpart W TSD, available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments for high flow samplers.

Comment: One commenter noted that because a high volume analyzer captures the emissions, OGI can be used to ensure that the high volume analyzer is collecting all of the emissions in its vicinity. The commenter stated that the EPA should clarify that an operator using OGI to ensure that a high volume analyzer is capturing all emissions may rely on the manufacturer's information on capacity limitations when reporting emissions.

Response: We agree with the commenter that OGI can be used to ensure that there is 100 percent capture of the leak emissions during the entire high volume sampling period, but we also note that OGI observations may also be used to indicate that 100 percent capture is not achieved. We have revised 40 CFR 98.234(d)(5) to specify that if 100 percent capture is documented throughout the measurement period by OGI, then the measured flow rate above the 70 percent maximum sampling rate provision can be used. However, if any emissions are observed escaping capture of the high volume sampler during a measurement period, then that measurement is considered invalid (*i.e.,* considered to be exceeding the quantitation capacity of the device) even if the measured flow rate is less than 70 percent of the sampling rate because the high volume sampler did not capture 100 percent of the emissions during that measurement period. We selected 70 percent of the manufacturer's maximum sampling rate as a reasonable proxy for efficient capture, but actual sampling rates may be lower depending on the battery power. Also, capture efficiency may be impacted by how the emissions are released from the leak source. We did not require OGI observations, but we agree that OGI observations provide an empirical means by which to assess capture efficiency and are preferred to and override the 70 percent maximum sampling rate criteria when OGI observations are used.

U. Industry Segment-Specific Throughput Quantity Reporting

1. Throughput Information for the Future Implementation of the Waste Emissions Charge

a. Summary of Final Amendments

As noted in section I.E. of this preamble, CAA section 136(f) specifies segment-specific thresholds (Waste Emissions Thresholds) for segments subject to the WEC. For the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments, the Waste Emissions Threshold is specified in CAA section 136(f)(1) as, ''(A) 0.20 percent of the natural gas sent to sale from such facility;'' or ''(B) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale.'' For the Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, LNG Storage, LNG Import and Export Equipment, and Onshore Natural Gas Transmission Pipeline industry segments, the Waste Emissions Threshold is defined in CAA section 136(f)(2) and (3) as a percentage of ''natural gas sent to sale from or through such facility,'' with the percentages specified varying by segment.

To align the subpart W reporting elements with text used in CAA section 136 and enable verification of throughput-related reporting elements, consistent with section II.C. of this preamble, the EPA is finalizing as proposed to add a combination of new reporting elements and amendments to existing segment-specific throughput reporting requirements in 40 CFR 98.236(aa).

The EPA is finalizing as proposed to add the word ''natural'' in front of ''gas'' at each occurrence where it is used in the throughput reporting elements in subpart W that are being revised to align with CAA section 136. We note that the CAA section 136 text uses the term ''oil'' and we are clarifying in this preamble that for the purposes of the waste emissions charge the term ''oil'' in CAA section 136 has the same meaning as ''crude oil'' as used in subpart W (which is used in the throughput reporting elements in subpart W and defined in subpart A of part 98).

The EPA is finalizing as proposed revisions to ensure that the verbiage of ''sent to sales'' or ''through the facility'' is reflected in the reporting elements, as applicable. The EPA is also finalizing as proposed in 40 CFR 98.236(aa) that the quantities sent to sales or through the facility be measured, as it is reasonable to expect that the quantities of these products are already closely tracked by reporters. The EPA expects that gas and hydrocarbon liquids are typically sold by the cubic foot or barrel, respectively, so measurements are important for owners and operators to determine the correct sales prices. Similarly, it is important to track quantities sent through the facility for a variety of reasons, such as ensuring that processes at the facility are optimized or meeting contractual obligations for transferring gas or hydrocarbon liquids to another owner or operator.

Subpart W currently requires onshore natural gas processing facilities to report the quantity of natural gas received at the gas processing plant in existing 40 CFR 98.236(aa)(3)(i); however, the rule does not currently specify whether the volume is all natural gas that enters the facility—including natural gas that passes through the facility without being processed further (*i.e.,* ''pass-through volumes'')—or just natural gas received for processing. As discussed in section III.U.4. of this preamble, to maintain consistency with subpart NN and reduce burden for fractionators, the EPA is finalizing revisions to 40 CFR 98.236(aa)(3)(i) as proposed to specify that the subpart W quantity of gas received is the gas received for processing and is also finalizing as proposed to specify that fractionators do not have to report a quantity under 40 CFR 98.236(aa)(3)(i) if they report under subpart NN.

However, to be consistent with CAA section 136(f)(2), the throughput should include all volumes of natural gas that pass through the facility or are sent to sales. Therefore, considering the amendments to 40 CFR 98.236(aa)(3)(i) and guidance that has been historically provided for 40 CFR 98.236(aa)(3)(ii) (as explained in the preamble to the 2023 Subpart W Proposal), a new reporting element for natural gas processing throughput is needed to fully capture all volumes through the facility (*i.e.,* those that are processed and those that pass through the facility which are not processed). As such, we are finalizing the new reporting element for the Onshore Natural Gas Processing industry segment in 40 CFR 98.236(aa)(3)(ix) as proposed to capture all natural gas that is processed and/or passed through the facility, consistent with the text in CAA section 136 (*i.e.,* ''natural gas sent to sale from or through facilities'').

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed general amendments to throughput information for the future implementation of the waste emissions charge.

Comment: One commenter stated that the EPA must expand the allowable methods to measure hydrocarbon liquid throughputs. The commenter stated that liquid throughputs are not commonly measured with flow meters but are instead usually determined by truck loading tickets, so the requirement to use a flow meter to determine quantities sent to sale or through the facility is not workable for hydrocarbon liquids.

Response: In assessing these commenters' assertion, the EPA reviewed available information about available flow meters to independently verify the commenters' claim and found that hydrocarbon liquids may be measured with meters such as ultrasonic and turbine flow meters. Ultrasonic flow measurement technology has been recognized in Chapter 5.8 of the API document, *Manual of Petroleum Measurement Standards.*[82] These meters ''infer the volumetric throughput by measuring the velocity over the flow area.'' [83] However, temperature is necessary to consider for crude oils as this can significantly change a meter's performance due to change in viscosity. The viscosity of each product needs to be specified over the operating temperature range. Further, we recognize that ultrasonic flow meters are Reynolds Number dependent and may be affected by the relationship between velocity and viscosity as well as by entrained solids, water, gas, and wax.[84] Additionally, turbine flow meters may be used to ''indicate flow rate and measure total throughput of a liquid line.'' [85] Manufacturers of turbine flow

[82] API. *Manual of Petroleum Measurement Standards*, Chapter 5.8: Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters Using Transit Time Technology. ANSI/API MPMS Ch. 5.8–2011. 2nd Edition, November 2011 (Errata 1 dated February 2014).

[83] Kalivoda, R. F*lowmeter Application Considerations: Knowing the Limits of Ultrasonics for Crude Oil Measurement.* September 26, 2010. Available at *https://www.piprocessinstrumentation.com/home/article/15554208/flowmeter-application-considerations*, last accessed April 12, 2024. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[84] *Id.*

[85] Cameron. Technical Specifications: NUFLO Liquid Turbine Flow Meters. 2013. *https://www.anythingflows.com/es/wp-content/uploads/2016/05/nuflo-liquid-turbine-flow-meters_fpd.pdf.*

Continued

meters state, ''Typical fluids and gases measured with turbine meters include hydrocarbons, chemicals, water, cryogenic liquids, air, natural gas, and industrial gases.'' [86] Therefore, the EPA is finalizing the requirements to determine throughput quantities that are sent to sale or through the facility using a flow meter that meets the requirements of 40 CFR 98.234(b).

2. Throughput Information for the Future Implementation of the Waste Emissions Charge for Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production

a. Summary of Final Amendments

For the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments, the current requirements for reporting throughputs of crude oil are combined with volumes of condensate. The EPA proposed to separate of these reporting elements into two distinct reporting elements in both 40 CFR 98.236(aa)(1)(i) and 98.236(aa)(2) based on a preliminary determination that these volumes will need to be reported separately in order to align with the CAA section 136(f) oil threshold for production facilities, when applicable. However, after further consideration and review of public comments, the EPA is not taking final action on that proposed revision. The existing definitions of ''sales oil'' and ''crude oil'' in subpart A both include condensate, and there is no indication that the phrase ''oil sent to sale'' as used in CAA section 136(f)(1) should be defined differently than the definitions subpart A.

For consistency with CAA section 136, the EPA is finalizing as proposed to use the phrase ''sent to sale'' in 40 CFR 98.236(aa)(1)(i)(B) and (C) and 40 CFR 98.236(aa)(2)(i) and (ii) instead of ''for sale,'' the phrase used in some of the existing data elements. This amendment is for consistency in language rather than any expected difference in the volumes to be reported or the interpretation of the terms, as the existing term was intended to have the same meaning.

Specifically for the Offshore Petroleum and Natural Gas Production industry segment, the existing throughput requirements are for ''gas handled'' and ''oil and condensate handled'' at the platform, which includes production volumes as well as volumes transferred via pipeline from another location. In order to provide consistency with the language in CAA section 136 across both production industry segments and help the EPA implement CAA section 136, the EPA is finalizing as proposed the revision of the reporting elements in 40 CFR 98.236(aa)(2) for the Offshore Petroleum and Natural Gas Production industry segment so they are analogous to those in Onshore Petroleum and Natural Gas Production.

The EPA is also finalizing additional throughput data elements to provide separate, well-level reporting of throughputs associated with wells in the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments that are permanently shut-in and plugged. These data elements are anticipated to be necessary for the implementation of the associated exemption in CAA section 136(f)(7). Specifically, in the 2024 WEC Proposal, the EPA proposed that these data elements would be used as equation inputs for the purposes of calculating emissions attributable to a permanent shut-in and plugged well for wells in the Onshore Petroleum and Natural Gas Production industry segment in reporting year 2024 and for wells in the Offshore Petroleum and Natural Gas Production in any reporting year. First, the EPA is finalizing as proposed to revise the phrase ''permanently taken out of production (*i.e.*, plugged and abandoned)'' in proposed 40 CFR 98.236(aa)(1)(ii)(D) and (H) to read ''permanently shut-in and plugged'' for consistency with the language used in CAA section 136. This amendment is for consistency in language rather than any expected difference in the wells to be reported or the interpretation of the terms. Second, the EPA is finalizing as proposed to require reporting of the quantities of natural gas and crude oil produced that is sent to sale during the reporting year for each well that is permanently shut-in and plugged. However, as discussed earlier in this section, the EPA is not taking final action on the proposed revision to require separate reporting for crude oil and condensate, so the final amendments require reporting of natural gas in 40 CFR 98.236(aa)(1)(iii)(C) and 40 CFR 98.236(aa)(2)(iii) and crude oil (including condensate) in 40 CFR 98.236(aa)(1)(iii)(D) and 40 CFR 98.236(aa)(2)(iv) for the Onshore Petroleum and Natural Gas Production industry segment and the Offshore Petroleum and Natural Gas Production industry segment, respectively.

Based on consideration of public comments, as well as the recent 2024 WEC Proposal, the EPA is not taking final action at this time on the proposed revision to require each Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged to report the total quantities of natural gas, crude oil, and condensate produced that is sent to sale in the reporting year for the wells on that well-pad. The EPA proposed these data elements anticipating that they may be necessary for the exemption in CAA section 136(f)(7) for wells that are permanently shut-in and plugged. However, the 2024 WEC Proposal does not use these data elements for the purposes of determining the quantity of emissions that may be exempted for a well that was permanently shut-in and plugged.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to throughput information for the future implementation of the waste emissions charge for the Onshore Petroleum and Natural Gas Production and Offshore Petroleum and Natural Gas Production industry segments.

Comment: Commenters disagreed with the EPA's proposal to require separate reporting of crude oil and condensate and explained that oil and condensate are often sold as one combined volume. Commenters explained that for offshore production facilities in particular, oil and condensate produced is sent onshore via single combined pipelines. Commenters stated that subpart A defines ''sales oil'' as produced crude oil or condensate measured at the production lease automatic custody transfer meter or custody transfer tank gauge and do not measure oil or condensate separately. One commenter stated that the IRA does not differentiate between oil, condensate, and natural gas.

Response: After further review of the requirements in CAA section 136, we agree that it is not necessary for condensate to be reported separately from crude oil. Section 136(f)(1) of the CAA uses the phrase ''barrels of oil sent to sale,'' and there is no indication that ''oil sent to sale'' should be defined differently than the term ''sales oil'' that already exists in subpart A. As the commenters noted, the definition of ''sales oil'' includes condensate, and the definition of ''crude oil'' in subpart A also includes condensate. Therefore, the

Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

[86] Hoffer Flow Controls, ''Turbine Flow Meters.'' *https://hofferflow.com/turbine-flow-meters*, last accessed April 12, 2024. Available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

EPA agrees that the amendment to use the term ''sent to sale'' in 40 CFR 98.236(aa)(1)(i)(C), 40 CFR 98.236(aa)(1)(iii)(D), and 40 CFR 98.236(aa)(2)(ii) and (iv) should address concerns with consistency with CAA section 136.

Comment: Commenters stated the proposal to require each Onshore Petroleum and Natural Gas Production well-pad with a well that was permanently shut-in and plugged to report the total quantities of natural gas, crude oil, and condensate produced that is sent to sale in the reporting year for the wells on that well-pad would result in duplicative reporting and is unnecessary.

Response: At the time of proposal, the EPA anticipated that these data elements may be useful in the future evaluation of the associated exemptions in CAA section 136(f)(7). However, the proposed provisions for the exemption for permanently shut-in and plugged wells in the 2024 WEC Proposal do not use the total quantities of natural gas and crude oil sent to sale in the reporting year for the wells on that well-pad. Therefore, we are not finalizing the requirement for reporting of throughput for each well-pad with a well that was permanently shut-in and plugged at this time.

3. Throughput Information for the Future Implementation of the Waste Emissions Charge for Onshore Petroleum and Natural Gas Gathering and Boosting

a. Summary of Final Amendments

To be consistent with the EPA's original intent for the throughput volumes for the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment, the EPA is finalizing amendments to 40 CFR 98.236(aa)(10)(ii) and (iv) with changes from proposal. We proposed to clarify that the downstream endpoints listed in the current reporting elements are examples of potential destinations. Based on consideration of public comment and further review of the language and background documentation, the EPA is instead revising 40 CFR 98.236(aa)(10)(ii) and (iv) to specify that the reported quantities should be the natural gas or hydrocarbon liquids, respectively, transported from the facility (rather than specifying that the reported quantities should be the natural gas or hydrocarbon liquids, respectively, transported to downstream operations such as one of those endpoints, as proposed). However, some gas may flow back upstream, for use at an onshore petroleum and natural gas facility. Section 136(f)(2) of the CAA indicates that the WEC should be based on the ''natural gas sent to sale from or through such facility'' but does not specify that the gas must be sent from the facility to a downstream endpoint. As a result of these amendments, the reported quantities must include all natural gas and hydrocarbon liquids transported from the facility (*i.e.*, transported to another basin, transported to another gathering system owner or operator, or transported outside of the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment).

In addition to reviewing the reported throughputs, we also reviewed the definitions in subpart W associated with the industry segment and the facility, specifically the definitions for ''gathering and boosting system'' and ''gathering and boosting system owner or operator'' in 40 CFR 98.238. We are finalizing as proposed to amend the definition of ''gathering and boosting system'' and ''gathering and boosting owner or operator'' in 40 CFR 98.238 to specify that these systems may receive natural gas and/or petroleum from one or more other onshore petroleum and natural gas gathering and boosting systems in addition to production facilities. We are also finalizing additional amendments to clarify that the downstream endpoints listed in the current provisions are examples of potential destinations. Specifically, we are revising the definition of ''gathering and boosting system owner or operator'' in 40 CFR 98.238 and the description of the industry segment in 98.230(a)(9) to add the phrase ''a downstream endpoint, typically'' before the list of the types of facilities that may receive the petroleum and/or natural gas.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to throughput information for the future implementation of the waste emissions charge for the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment.

Comment: Commenters supported the EPA's proposed changes to the gathering and boosting throughput reporting requirements but noted that the term ''downstream endpoint'' is too narrow because gas sometimes exits the gathering system to an ''upstream'' location, such as back to upstream producers for various uses. Commenters also requested that the EPA specify that Onshore Petroleum and Natural Gas Gathering and Boosting industry segment reporters should account for gas that flows through multiple compressor stations (''sites'') in series within the same basin by revising the list of examples of downstream endpoints to include ''another gathering and boosting site or facility.''

Response: The EPA agrees with the commenters' statement that ''downstream endpoint'' is too narrow and that it would be more accurate for facilities to report all natural gas and hydrocarbon liquids transported from the facility regardless of destination, including quantities that are transported to another basin, quantities that are transported to another gathering system owner or operator, and quantities that are transported to a facility in a different industry segment or source category. In response to this comment, the EPA is finalizing amendments to 40 CFR 98.236(aa)(10)(ii) to specify that the natural gas is transported ''from the facility,'' regardless of whether the endpoint is downstream of the facility.

However, the EPA disagrees with the commenters' request to report the total throughput reported as the quantity transported from each gathering and boosting site where that quantity is transported to a site that is part of the same facility with respect to onshore petroleum and natural gas gathering and boosting. This would allow reporters to count flows multiple times and significantly increase the throughput volumes for gathering and boosting facilities. Congress established methane waste emissions thresholds for gathering and boosting facilities under CAA section 136 with reference to the existing subpart W facility definitions. The EPA proposed revisions to the throughput requirements that would align with the requirements of CAA section 136. The EPA generally proposed to maintain the existing approach to facility throughputs, with limited revisions to ensure that all throughput transported from the facility is included and to align with the terminology used in CAA section 136.

4. Onshore Natural Gas Processing and Natural Gas Distribution Throughputs Also Reported Under Subpart NN

For the reasons stated in the preamble to the 2023 Subpart W Proposal, the EPA is finalizing as proposed the elimination of duplicative elements from subpart W for facilities that report to subpart NN and two other data elements for natural gas distribution companies, consistent with section II.C. of this preamble. The EPA received only supportive comments regarding the removal of these data elements from subpart W. See the document *Summary* *of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule* in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

Onshore Natural Gas Processing plants are required to report seven facility-level throughput-related items under subpart W, as specified in existing 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 CH4 and CO2 in the natural gas received, and an indication of whether the facility fractionates NGLs. The EPA is finalizing several reporting requirements in 40 CFR 98.236(aa)(3) as proposed for Onshore Natural Gas Processing plants that both fractionate NGLs and also report as a supplier under subpart NN. First, to clarify which facilities have data overlap between subparts W and NN, the EPA is adding 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. We note that the final wording for this new data element is slightly changed from proposal to clarify that the facility report must include subpart NN data under the same e-GGRT identification number and the same calendar year as the Onshore Natural Gas Processing plant. Some facilities may not report under both subparts ever year, or some owners or operators may choose to report subpart NN data using a different e-GGRT identification number, and the language of the final data element clarifies how a reporter should respond to the data element. Next, the EPA is finalizing as proposed to specify in 40 CFR 98.236(aa)(3) introductory text that facilities that indicate that they both fractionate NGLs and report as a supplier under subpart NN under the same e-GGRT identification number and for the same calendar year 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); this data will continue to be reported under 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, thus, maintaining the ability to verify associated emissions reported under subpart W. See table 2 of this preamble for more information.

These facilities will 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 will continue to report all of the reporting elements for natural gas processing plants as specified in 40 CFR 98.236(aa)(3).

Natural Gas Distribution companies are also required to report seven throughput volumes under subpart W, as specified in existing 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 is finalizing the removal of the duplicative reporting elements for throughput for LDCs in 40 CFR 98.236(aa)(9)(i) through (iv), as proposed. See table 3 of this preamble for more information.

Finally, the EPA is finalizing as proposed 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). As a result of removing all of the 40 CFR 98.236(aa)(9) data elements for the reasons explained in this section of this preamble, the EPA is reserving paragraph 40 CFR 98.236(aa)(9).

Table 2 of this preamble shows all the duplicative data elements that the EPA is removing from subpart W for facilities that also report to subpart NN.

Table 2. List of Subpart W Data Elements 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 LDCs
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

5. Onshore Natural Gas Transmission Pipeline Throughputs

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 existing 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. For the reasons stated in the preamble to the 2023 Subpart W Proposal, the EPA is finalizing as proposed to amend 40 CFR 98.236(aa)(11)(ii) and (iii) to replace the term ''in-system'' with clarifying language that specifies withdrawals/additions of natural gas from storage are 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.D. of this preamble. The EPA received only supportive comments regarding these amendments. See the document Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule in Docket ID. No. EPA–HQ–OAR–2023–0234 for these comments and the EPA's responses.

V. Other Final 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 finalizing throughout subpart W, consistent with section II.D. of this preamble.

BILLING CODE 6590–50–P

Table 3. Final Technical Corrections to Subpart W

Section (40 CFR)	Description of Amendment
Amendments that are Finalized as Proposed	
§ 98.230(a)(2)	Revise the instance of "well pad" to read "well-pad" to correct inconsistency in the term.
§ 98.230(a)(9)	Remove the ")" after "GOR" to correct a typographical error.
§ 98.232 introductory text	Add reference to paragraph (l) of this section to clarify that annual reports must include the information specified in paragraph (l) if applicable.
§§ 98.232(c)(17), (d)(5) and (j)(3)	Revise the instances of "acid gas removal vents" to read "acid gas removal unit vents" for consistency with the defined term "Acid gas removal unit (AGR)" in 40 CFR 98.238.
§ 98.233(d)	Revise the instances of "AGR unit" to read "AGR" for consistency with the defined term "Acid gas removal unit (AGR)" in 40 CFR 98.238.
§§ 98.233(e)(1)(x), 98.236(e)(1)(xi) and (xii)	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(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(k)	Revise the introductory sentence in this section to specify that 40 CFR 98.233(k) does not apply to condensate storage tanks that route emissions to flares or other controls for consistency with proposed amendment that would move procedures for calculating flared emissions from 40 CFR 98.233(k) to 40 CFR 98.233(n).
§§ 98.233(o) introductory text and (p) introductory text	Move the last sentence in each paragraph to be the second sentence to clarify that the calculation methodology for compressors routed to flares, combustion, or vapor recovery systems apply to all industry segments.
§§ 98.233(o) introductory text and (p) introductory text, 236(o)(2)(ii) and (p)(2)(ii)	Revise the instances of "vapor recovery" to read "vapor recovery system" to correct inconsistency in the term.
§ 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.

Section (40 CFR)	Description of Amendment
§ 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(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)(2)(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.
§ 98.234(f)	Remove and reserve paragraph for provisions for best available monitoring methods for RY2015, as reports for that reporting year can no longer be submitted to the EPA.
§ 98.234(g)	Remove and reserve paragraph for provisions for best available monitoring methods for RY2016, as reports for that reporting year can no longer be submitted to the EPA.
§ 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(d)(2)(iii)(D)	Revise "natural gas flow rate" to read "natural gas feed flow rate" for consistency with the parameters listed in 40 CFR 98.233(d)(4)(i).
§§ 98.236(e)(1) and (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(k)(1)(iii)	Correct the internal cross reference from "§ 98.233(k)(2)" to "§ 98.233(k)(1)."
§ 98.236(k)(2)(i)	Add a cross reference to 40 CFR 98.233(k)(2) and revise sentence to specify that the reported method used to measure leak rates should be one provided in that section.
§§ 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)).

Section (40 CFR)	Description of Amendment
§ 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.
Tables W-1 through W-7 to subpart W of part 98	Replace tables W-1 through W-7 with new tables W-1 through W-6 to reorganize and consolidate the emission factor tables so that there are separate tables by pollutant (whole gas, THC, and CH_4) and by type of factor (population and leaker emission factors). Update cross references to these tables accordingly throughout subpart W.
Amendments that were not Proposed but are Finalized	
§§ 98.236(j)(1)(vii)(A)-(C)	Revise the instances of "oil" and "produced oil or condensate" to read "hydrocarbon liquids" for consistency with updates to the introduction paragraph (j)(1).
§ 98.233(j)(2)(i)	Revise the instance of "atmosphere" in the first sentence to read "atmospheric" to correct a typographical error.
§ 98.233(j)(3)(ii)	Revise the instance of "atmosphere" in equation W-15B term definition "EF_{CH4}" to read "atmospheric" to correct a typographical error.
§ 98.233(q)(3)(viii)(B)	Correct the internal cross reference from "paragraph (q)(3)(vii)(A) of this section" to "paragraph (q)(3)(viii)(A) of this section."
Amendments that were Proposed but are Finalized With Changes	
§ 98.233(j)(1)	Remove "and N_2O (when flared)" from the first sentence and revise the last sentence to specify the GHGs, including N_2O, that must be calculated for flared emissions. This is consistent with how other emission sources specify the GHGs to be calculated from flared emissions.
§ 98.233(j)(7)(i)	Correct proposed references to § 60.5397b to instead reference § 60.5395b and § 60.5416b for cover monitoring requirements on atmospheric storage tanks.
§ 98.233(n)(5)	Correct the cross reference in the definition of the equation variable "Y_j" from paragraph (n)(1) to (n)(4).
§ 98.233(r), equations W-32A and W-32B	Correct the cross reference in the definition of the equation variable "$E_{s,MR,i}$" and the equation variable "$Count_{MR}$" from paragraph (q)(9) to (q)(2)(xi) or (q)(3)(viii)(B).
§ 98.234(e)	Renumber the Peng Robinson equation of state from equation W-41 to equation W-47 to provide space for six new equations related to new source types in proposed 40 CFR 98.233(dd) and (ee).

Section (40 CFR)	Description of Amendment
§§ 98.236(c)(5)(i) through (iv)	Edits to explicitly state that the reporting requirements in this section apply to pneumatic pumps that are vented direct to atmosphere and for which emissions are calculated using the default emission factor (Calculation Method 3). Revise "operational" to "pumping liquid" in the description of the reported time element in 40 CFR 98.236(c)(5)(ii) to be consistent with the proposed change described in section III.E.3. of this preamble for Calculation Method 3.
Amendments that were Proposed but are not Finalized	
§ 98.236(x)(1)	Retain the current requirement to report Sub-basin ID instead of the proposed Well-pad ID, to maintain consistency with 40 CFR 98.233(x) introductory text.

BILLING CODE 6560–50–C

IV. Effective Date of the Final Amendments

The EPA is finalizing the effective date of the amendments with some updates from proposal, that will phase in the final amendments. The effective dates listed in the **DATES** section of this preamble reflect when the amendments will be published in the CFR. As described in more detail in section IV.A. of this preamble, we are finalizing that the majority of the final amendments will become effective on January 1, 2025, as proposed, and that reporters will implement all but a few of those changes beginning with reports prepared for RY2025 and submitted by March 31, 2026. The submission date for RY2025 reports is over a year after the finalization of this rule, thus providing a reasonable period for reporters to adjust to any final amendments that require a change to data collection, calculation methods, or reporting. The requirements that will become effective on January 1, 2025, and must be implemented beginning with reports prepared for RY2024 and submitted by March 31, 2025 are reporting requirements that do not require additional data collection or calculations. In addition, as described in more detail in section IV.B. of this preamble, the EPA is finalizing that certain optional additional calculation methods and other provisions that allow owners and operators of applicable facilities to submit empirical emissions data, consistent with CAA section 136(h), will become effective on July 15, 2024. This earlier effective date will allow reporters the option to elect to use those methods for RY2024. Specific information regarding what provisions are allowed or required each year is provided in sections IV.A. and IV.B. of this preamble.

We are also finalizing that the CBI determinations for new and substantially revised data elements discussed in section V. of this preamble become effective on the same date that the new data element or final revisions to existing data elements become effective. The exception is one circumstance, discussed in detail in section V. of this preamble, where the final determination covers data included in annual GHG reports submitted for prior years. In all cases, as proposed, the final determination 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, 2025.

A. Amendments That Are Effective on January 1, 2025

Table 4 of this preamble lists the affected subparts, the final revisions that are effective on January 1, 2025, and the RY report in which those changes will first be reflected. January 1, 2025, is the effective date, which is the date that the CFR regulatory text is revised to reflect those changes. However, the report in which that amendment will first be reflected is either RY2024 or RY2025, depending upon the substance of that change (i.e., what that change requires the reporter to do to comply with it).

Changes with effective date January 1, 2025, that must be reflected starting with the RY2024 report are those that require no changes to be made by reporters during the reporting year and thus provide reporters a reasonable time to adjust to these certain final amendments prior to submission of the RY2024 report. These are also reporting elements necessary for implementation of WEC. Specifically, the final reporting of the quantities of natural gas and crude oil produced that is sent to sale in the calendar year for each well permanently shut-in and plugged (40 CFR 98.236(aa)(1)(iii)(C) and (D) and 40 CFR 98.236(aa)(2)(iii) and (iv)) become effective on January 1, 2025 and reporters must, as applicable, include that information in their reports prepared for RY2024 and submitted March 31, 2025.

Changes with effective date January 1, 2025 that must be reflected starting with the RY2025 reports include requirements to begin reporting emissions for new emission sources, both those that are being added to subpart W for the first time in this final rule (*e.g.*, other large release events, crankcase venting) and those that expand the applicability of reporting for emission source types in subpart W to additional industry segments, as described in section III.C.1. of this preamble, as well as requirements to begin accounting for additional emission points from existing emission source types (*e.g.*, methane slip from combustion equipment). They also include changes that affect monitoring or data collection requirements, such as requirements for certain simulation inputs for AGRs, dehydrators, and atmospheric storage tanks to be based on measurement, and changes to required calculation methodologies, such as determination of the flow rate and composition of gas routed to a flare if continuous monitors are not present.

Table 4. Part 98 Amendments Effective January 1, 2025

Subpart affected	Revisions reflected starting with RY2024 reports (40 CFR)[a]	Revisions reflected starting with RY2025 reports (40 CFR)[b]
A—General Provisions	N/A	All changes in subpart
C—General Stationary Fuel Combustion Sources	N/A	All changes in subpart
W—Petroleum and Natural Gas Systems	§§ 98.236(aa)(1)(iii)(C) and (D), 98.236(aa)(2)(iii) and (iv))	§§ 98.230(a); 98.232; 98.233; 98.234; 98.235(f); 98.236 (except 98.236(aa)(1)(iii)(C) and (D), 98.236(aa)(2)(iii) and (iv)); 98.237(g); 98.238; all tables in subpart

[a] RY2024 reports will be submitted to the EPA by March 31, 2025.

[b] RY2025 reports will be submitted to the EPA by March 31, 2026.

B. Amendments That Are Effective July 15, 2024

Table 5 of this preamble lists the final amendments that are effective July 15, 2024, all of which may be reflected in the RY2024 report for the first time if elected by the reporter. These amendments include optional additional calculation methods and other provisions that allow owners and operators of applicable facilities to submit empirical emissions data, consistent with CAA section 136(h). This earlier effective date will allow reporters the option to elect to use those methods for RY2024. The amendments to calculation methodologies that are effective July 15, 2024 for various emission source types specify that reporters may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs. For example, if a reporter installed a continuous flow meter that is capable of meeting the requirements of 40 CFR 98.234(b) on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices prior to January 1, 2024, the reporter may use Calculation Method 1 for natural gas pneumatic devices for all of RY2024, not just the period between July 15, 2024 and December 31, 2024.

BILLING CODE 6560–50–P

Table 5. Subpart W Amendments Effective July 15, 2024

Emission source type	Description of amendment	Revisions reflected starting with RY2025 reports (40 CFR)[a]	Section of this preamble with details	Current requirements for specific sources
Natural gas pneumatic devices	Add Calculation Method 1 as an option (continuous flow meter on the natural gas supply line), with associated reporting Beginning with RY2025, use of Calculation Method 1 is required if a gas flow meter is present	§§ 98.233(a)(1); 98.236(b)(2) and (3)	III.E.1.	Use default population emission factors
Natural gas pneumatic devices	Add Calculation Method 2 as an option (measure the volumetric flow rate of natural gas pneumatic devices venting directly to the atmosphere), with associated reporting	§§ 98.233(a)(2); 98.236(b)(2) and (4)	III.E.1.	Use default population emission factors
Natural gas pneumatic devices	Add Calculation Method 3 as an option at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities (monitor intermittent bleed pneumatic devices for malfunctions and either measure or use population emission factors for continuous high bleed and continuous low bleed pneumatic devices), with associated reporting	§§ 98.233(a)(3); 98.236(b)(2) and (5)	III.E.2.	Use default population emission factors

Emission source type	Description of amendment	Revisions reflected starting with RY2025 reports (40 CFR)[a]	Section of this preamble with details	Current requirements for specific sources
Natural gas driven pneumatic pumps	Add Calculation Method 1 as an option (continuous flow meter on the natural gas supply line), with associated reporting Beginning with RY2025, use of Calculation Method 1 is required if a gas flow meter is present	§§ 98.233(c)(1); 98.236(c)(2) and (3)	III.E.1.	Use default population emission factor
Natural gas driven pneumatic pumps	Add Calculation Method 2 as an option (measure the volumetric flow rate of natural gas driven pneumatic pumps venting directly to the atmosphere), with associated reporting	§§ 98.233(c)(2); 98.236(c)(2) and (4)	III.E.1.	Use default population emission factor
Acid gas removal vents	Allow use of Calculation Method 4 if a CEMS is not available but a vent meter is installed, with associated reporting	§§ 98.233(d)(2), (4), and (12); 98.236(d)(2)(iii)	III.F.1.	Use Calculation Method 2 (vent meter and composition analyzer or sampling)
Dehydrator vents	Allow glycol dehydrators with annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day to use either Calculation Method 1 or 2, with minor revisions to reporting	§§ 98.233(e) introductory text, (e)(1) introductory text, and (e)(2); 98.236(e) introductory text, (e)(1) introductory text, and (e)(2)	III.G.1.	Use Calculation Method 2 (default population emission factor)

Emission source type	Description of amendment	Revisions reflected starting with RY2025 reports (40 CFR)[a]	Section of this preamble with details	Current requirements for specific sources
Completions and workovers with hydraulic fracturing	Allow use of a multiphase flow meter from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation, with associated reporting	§§ 98.233(g) introductory text, (g)(1)(i) and (iv); 98.236(g)(5)(iv) and (g)(6)(iii)	III.I.	Use gas flow meter
Blowdown vent stacks	Allow use of engineering estimates based on best available information to determine the temperature and pressure for emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities	§ 98.233(i)(2)(i)	III.J.	Subpart W does not currently allow use of engineering estimates for emergency blowdowns at onshore natural gas transmission pipeline facilities
Atmospheric storage tanks	Allow wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day to use either Calculation Method 1 or 2	§§ 98.233(j) introductory text and (j)(3)	III.K.3. and 5.	Use Calculation Method 2 (assume all CH_4 and CO_2 in liquid are emitted)
Atmospheric storage tanks	Allow wells, gas-liquid separators, or non-separator equipment with annual average daily throughput less than 10 barrels per day to use either Calculation Method 1, 2, or 3 with minor revisions to reporting	§§ 98.233(j) introductory text and (j)(2); 98.236(j)(2)(i)(A)	III.K.3.	Use Calculation Method 3 (default population emission factor)

Emission source type	Description of amendment	Revisions reflected starting with RY2025 reports (40 CFR)[a]	Section of this preamble with details	Current requirements for specific sources
Associated gas venting and flaring	Allow use of continuous gas flow measurement device, with associated reporting Beginning with RY2025, use of gas flow measurements is required if a continuous gas flow measurement device is present, with minor revisions to reporting	§§ 98.233(m)(1) through (3); 98.236(m)(4) through (7)	III.M.	Use calculation based on gas to oil ratio, volume of oil produced, and volume of associated gas sent to sales
Centrifugal compressors and Reciprocating compressors	Allow emissions calculation from volumetric emission measurements for compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility, with associated reporting Beginning with RY2025, sites that are subject to NSPS OOOOb or an applicable approved state plan or applicable Federal plan in 40 CFR part 62 must calculate emissions from volumetric emission measurements	§§ 98.233(o)(10) and (p)(10); 98.236(o) introductory text and (p) introductory text	III.O.3.	Use default population emission factors
Equipment leak surveys	Add option to measure the volumetric flow rate of each leak identified during a leak survey and develop site-specific emission factors, with associated reporting	§§ 98.233(q)(1), (3), and (4); 98.236(q)(1) and (2)	III.P.3. and 4.	Use default leaker emission factors
Equipment leak surveys	Exempt equipment in vacuum service from survey and emission estimation requirements	§ 98.233(q) introductory text	III.P.7.	Include in leak surveys

Emission source type	Description of amendment	Revisions reflected starting with RY2025 reports (40 CFR)[a]	Section of this preamble with details	Current requirements for specific sources
Offshore production	Allow use of BOEM methods in years other than BOEM emissions study publication years, with minor revisions to reporting Beginning with RY2025, BOEM methods must be used in years that overlap with a BOEM emissions inventory year and any other reporting year in which the BOEM's emissions reporting system is available and the facility has the data needed to use BOEM's emissions reporting system	§§ 98.233(s)(1) and (2)	III.R.	Use adjustments based on the operating time for the facility
Combustion equipment	Allow use of subpart C calculations for natural gas that is not pipeline quality but meets specified conditions;	§§ 98.233(z)(1) and (2)	III.S.1.	Use subpart W calculation methods
Combustion equipment	Allow use of engineering estimates based on best available data to determine the concentration of each constituent in the flow of gas to combustion units.	§ 98.233(z)(2)(ii)	III.S.1.	Use continuous gas composition analyzer or annual average gas composition based on the most recent available analysis of the facility's produced natural gas

Emission source type	Description of amendment	Revisions reflected starting with RY2025 reports (40 CFR)[a]	Section of this preamble with details	Current requirements for specific sources
Natural gas pneumatic devices, Natural gas driven pneumatic pumps, and Equipment leak surveys	Definitions in 40 CFR 98.238 for "centralized oil production site," "gathering and boosting site," "gathering compressor station," "gathering pipeline site," and "well-pad site."	§ 98.238	III.D.[b]	All calculations at facility level

[a] The lists of amended sections in this column include the sections with the significant revisions relevant to the amendment; they may not include every paragraph where conforming revisions are needed.

[b] Reporters will not report emissions or activity data for these sites in RY2024 but the definitions are needed to implement measurement-based calculation methodologies for natural gas pneumatic devices, natural gas driven pneumatic pumps, and equipment leaks.

BILLING CODE 6560–50–C

V. Final Confidentiality and Reporting Determinations for Certain Data Reporting Elements

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

A. EPA's Approach To Assess Data Elements

In the 2023 Subpart W Proposal, the EPA proposed to assess data elements for eligibility of confidential treatment using a revised approach, in response to *Food Marketing Institute* v. *Argus Leader Media*, 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*).[87] The EPA proposed that the *Argus Leader* decision did not affect our approach to designating data elements as ''inputs to emission equations'' or our previous approach for designating new and revised reporting requirements as ''emission data.'' We proposed to continue identifying new and revised reporting elements that qualify as ''emission data'' (*i.e.,* data necessary to determine the identity, amount, frequency, or concentration of the emission emitted by the reporting facilities) by evaluating the data for assignment to one of the four data categories designated by the 2011 Final CBI Rule (76 FR 30782, May 26, 2011) to meet the CAA definition of ''emission data'' in 40 CFR 2.301(a)(2)(i) (hereafter referred to as ''emission data categories''). Refer to section II.B. of the July 7, 2010 proposal (75 FR 39094) for descriptions of each of these data categories and the EPA's rationale for designating each data category as ''emission data.'' For data elements designated as ''inputs to emission equations,'' the EPA maintained the two subcategories, data elements entered into e-GGRT's Inputs Verification Tool (IVT) and those directly reported to the EPA. Refer to section V.C. of the preamble to the 2023 Subpart W Proposal for further discussion of ''inputs to emission equations.''

In the 2023 Subpart W Proposal, for new or revised data elements that the EPA did not propose to designate as ''emission data'' or ''inputs to emission equations,'' the EPA proposed a revised approach for assessing data confidentiality. We proposed to assess each individual reporting element according to the new *Argus Leader* standard. So, we evaluated each data element individually to determine whether the information is customarily and actually treated as private by the reporter and proposed a confidentiality determination based on that evaluation.

The EPA received several comments on its proposed approach in the 2023 Subpart W Proposal. The commenters' concerns and the EPA's responses thereto are provided in the document Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule in Docket ID. No. EPA–HQ–OAR–2023–0234. Following consideration of the comments received, the EPA is not revising this approach and is continuing to assess data elements for confidentiality determinations as described in the 2023 Subpart W Proposal. We are also finalizing the specific confidentiality determinations and reporting determinations as

[87] Available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

described in sections V.B. and V.C. of this preamble.

B. Final Confidentiality Determinations and Emissions Data Designations

1. Final Confidentiality Determinations for New and Revised Data Elements

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

The EPA is not finalizing the proposed confidentiality determinations for certain data elements in subpart W because the EPA is not taking final action on the requirements to report these data elements at this time (see section III. of this preamble for additional information). These data elements are listed in Table 4 of the memorandum, *Confidentiality Determinations and Emission Data Designations for Data Elements in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems,* available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

For one data element, the EPA proposed a confidentiality determination in the 2023 Subpart W Proposal but is not finalizing a confidentiality determination at this time. In the 2023 Subpart W Proposal, the EPA proposed a confidentiality determination of ''Eligible for Confidential Treatment'' for 40 CFR 98.236(aa)(3)(ix), the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year. In the 2024 WEC Proposal, the EPA re-proposed the confidentiality status for this data element as ''No Determination.'' We intend to consider comments submitted on the 2024 WEC rulemaking on this proposed confidentiality status before finalizing a confidentiality determination for this data element through rulemaking. We intend to make this determination along a similar timeline as the final WEC rule.

In some cases, the EPA is finalizing revisions from the proposed rule that include new data elements for which the EPA did not propose a confidentiality determination. These data elements are listed in table 6 of this preamble and Table 5 of the memorandum, *Confidentiality Determinations and Emission Data Designations for Data Elements in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems,* available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. Because these data elements were not included in the proposal, the EPA was unable to solicit public comment on confidentiality determinations for these data elements. Accordingly, we are not finalizing confidentiality determinations for any of these data elements at this time.

BILLING CODE 6560–50–P

Table 6. New Data Elements from Proposal to Final for Which the EPA is Not Finalizing Confidentiality Determinations or Emission Data Designations

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(b)(6)(iii)	Annual CO_2 emissions, in metric tons CO_2, for each type of natural gas pneumatic device calculated according to Calculation Method 4 in § 98.233(a)(4).
W	§ 98.236(b)(6)(iv)	Annual CH_4 emissions, in metric tons CH_4, for each type of natural gas pneumatic device calculated according to Calculation Method 4 in § 98.233(a)(4).
W	§ 98.236(d)(1)(ii)(A)	If the acid gas removal unit was routed to a flare, indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(d) as specified in § 98.233(n)(3)(ii)(B).
W	§ 98.236(d)(1)(ii)(C)	If the acid gas removal unit was routed to a flare, the unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the acid gas removal unit was routed
W	§ 98.236(d)(1)(ii)(D)	If the acid gas removal unit was routed to a flare, the unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the acid gas removal unit.
W	§ 98.236(d)(1)(iv)	Whether the acid gas removal unit or nitrogen removal unit vent was routed to a vapor recovery system.
W	§ 98.236(d)(1)(iv)	If the acid gas removal unit or nitrogen removal unit vent was routed to vapor recovery system, whether it was routed for the entire year or only part of the year.
W	§ 98.236(d)(2)(iii)(O)(*3*)	If the calculated percent difference between the vent volumes ("PD" from equation W-4D to § 98.233) is greater than 20 percent, provide a brief description of the reason for the difference.
W	§ 98.236(e)(4)(i)	For dehydrators that were routed to flares, indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(e) as specified in § 98.233(n)(3)(ii)(B).

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(e)(4)(ii)	For dehydrators that were routed to flares, indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.
W	§ 98.236(e)(4)(iii)	For dehydrators that were routed to flares, the unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the dehydrator vent was routed.
W	§ 98.236(e)(4)(iv)	For dehydrators that were routed to flares, the unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the dehydrator.
W	§ 98.236(g)(5)(iv)(A)	Whether the flow rate during the initial flowback period was determined using a recording flow meter (digital or analog) installed on the vent line, downstream of a separator.
W	§ 98.236(g)(5)(iv)(B)	Whether the flow rate during the initial flowback period was determined using a multiphase flow meter upstream of the separator.
W	§ 98.236(g)(5)(iv)(C)	Whether the flow rate during the initial flowback period was determined using equation W-11A or W-11B to § 98.233.
W	§ 98.236(g)(5)(v)(A)	Whether the flow rate when sufficient quantities are present to enable separation was determined using a recording flow meter (digital or analog) installed on the vent line, downstream of a separator.
W	§ 98.236(g)(5)(v)(B)	Whether the flow rate when sufficient quantities are present to enable separation was determined using equation W-11A or W-11B to § 98.233.
W	§ 98.236(g)(6)(iii)	If a multiphase flowmeter was used to measure the flow rate during the initial flowback period, report the average flow rate measured by the multiphase flow meter from the initiation of flowback to the beginning of the period of time when sufficient quantities of gas present to enable separation in standard cubic feet per hour.
W	§ 98.236(g)(10)(i)	For completion(s) or workover(s) with hydraulic fracturing that were routed to flares, indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(g) as specified in § 98.233(n)(3)(ii)(B).

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(g)(10)(ii)	For completion(s) or workover(s) with hydraulic fracturing that were routed to flares, indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.
W	§ 98.236(g)(10)(iii)	For completion(s) or workover(s) with hydraulic fracturing that were routed to flares, the unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.
W	§ 98.236(g)(10)(iv)	For completion(s) or workover(s) with hydraulic fracturing that were routed to flares, the unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section.
W	§ 98.236(h)(2)(viii)(A)	For completion(s) without hydraulic fracturing that were routed to flares, indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) as specified in § 98.233(n)(3)(ii)(B).
W	§ 98.236(h)(2)(viii)(B)	For completion(s) without hydraulic fracturing that were routed to flares, indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.
W	§ 98.236(h)(2)(viii)(C)	For completion(s) without hydraulic fracturing that were routed to flares, the unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.
W	§ 98.236(h)(2)(viii)(D)	For completion(s) without hydraulic fracturing that were routed to flares, the unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section.
W	§ 98.236(h)(4)(vi)(A)	For workover(s) without hydraulic fracturing that were routed to flares, indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) as specified in § 98.233(n)(3)(ii)(B).
W	§ 98.236(h)(4)(vi)(B)	For workover(s) without hydraulic fracturing that were routed to flares, indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(h)(4)(vi)(C)	For workover(s) without hydraulic fracturing that were routed to flares, the unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.
W	§ 98.236(h)(4)(vi)(D)	For workover(s) without hydraulic fracturing that were routed to flares, the unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section.
W	§ 98.236(j)(4)(i)	For atmospheric pressure storage tanks that were routed to flares, indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(j) as specified in § 98.233(n)(3)(ii)(B).
W	§ 98.236(j)(4)(ii)	For atmospheric pressure storage tanks that were routed to flares, indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.
W	§ 98.236(j)(4)(iii)	For atmospheric pressure storage tanks that were routed to flares, the unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the atmospheric pressure storage tank was routed.
W	§ 98.236(j)(4)(iv)	For atmospheric pressure storage tanks that were routed to flares, the unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the atmospheric pressure storage tank.
W	§ 98.236(m)(3)(i)	If associated gas was flared, indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(m) as specified in § 98.233(n)(3)(ii)(B).
W	§ 98.236(m)(3)(ii)	If associated gas was flared, indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.
W	§ 98.236(m)(3)(iii)	If associated gas was flared, the unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.
W	§ 98.236(m)(3)(iv)	If associated gas was flared, the unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section.

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(n)(3)	If you determine flow or composition for a combined stream from multiple source types, then report the source type that provides the most gas to the combined stream.
W	§ 98.236(n)(7)	Indicate whether you measured total flow at the inlet to the flare as specified in § 98.233(n)(3)(i) or whether you determined flow for individual streams routed to the flare as specified in § 98.233(n)(3)(ii).
W	§ 98.236(n)(7)	If you determined flow for individual streams, indicate for each stream whether flow was determined using a continuous flow measurement device, parameter monitoring and engineering calculations, or other simulation or engineering calculation methods.
W	§ 98.236(n)(8)	If you determined composition for individual streams, indicate for each stream whether composition was determined using a continuous gas composition analyzer, sampling and analysis, or other simulation or engineering calculation methods.
W	§ 98.236(n)(9)	Indicate whether you directly measured annual average HHV of the inlet stream to the flare as specified in § 98.233(n)(8)(i), calculated the annual average HHV of the inlet stream to the flare based on composition of the inlet stream as specified in § 98.233(n)(8)(ii), directly measured the annual average HHV of individual streams routed to the flare as specified in § 98.233(n)(8)(iii), or calculated the annual average HHV of individual streams based on their composition as specified in § 98.233(n)(8)(iv).
W	§ 98.236(n)(10)	The calculated flow-weighted annual average HHV of the inlet stream to the flare determined as specified in § 98.233(n)(8)(iii)(B) or (iv)(B).
W	§ 98.236(n)(13)(i)(A)	If you use Tier 1, the number of days in periods of 15 or more consecutive days when you did not conform with all cited provisions in § 98.233(n)(1)(i).
W	§ 98.236(n)(13)(ii)(B)	If you use Tier 2 and you are not required to comply with part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, indicate whether you are electing to comply with § 98.233(n)(1)(ii)(A), (B), (C), or (D).
W	§ 98.236(n)(13)(ii)(D)	If you use Tier 2, number of days in periods of 15 or more consecutive days when you did not conform with all cited provisions in § 98.233(n)(1)(ii).

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(n)(13)(iii)	If you use Tier 2, indicate if you use an alternative test method approved under § 60.5412b(d) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.
W	§ 98.236(n)(13)(iii)	If you use an approved alternative test method, indicate the approved destruction efficiency for the method.
W	§ 98.236(n)(13)(iii)	If you use an approved alternative test method, indicate the date when you started to use the method.
W	§ 98.236(n)(13)(iii)	If you use an approved alternative test method, indicate the name or ID of the method.
W	§ 98.236(y)(11)(v)	Provide an indication if you received a super-emitter release notification from the EPA after December 31 of the reporting year for which investigations are on-going such that the annual report that has been submitted may be revised and resubmitted pending the outcome of the super-emitter investigation.
W	§ 98.236(dd)(1)(iii)	For each well for which you used Calculation Method 1 to calculate natural gas emissions from mud degassing, target hydrocarbon-bearing stratigraphic formation to which the well is drilled.
W	§ 98.236(dd)(3)(i)	For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, Well ID number.
W	§ 98.236(dd)(3)(ii)(A)	For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, for the time periods you used Calculation Method 1, approximate total depth below surface, in feet.
W	§ 98.236(dd)(3)(ii)(B)	For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, for the time periods you used Calculation Method 1, target hydrocarbon-bearing stratigraphic formation to which the well is drilled.
W	§ 98.236(dd)(3)(ii)(G)	For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, for the time periods you used Calculation Method 1, annual CH_4 emissions, in metric tons CH_4, from well drilling mud degassing, calculated according to § 98.233(dd)(1).
W	§ 98.236(dd)(3)(iii)(B)	For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, for the time periods you used Calculation Method 2, the composition of the drilling mud: water-based, oil-based, or synthetic.

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(dd)(3)(iii)(C)	For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, for the time periods you used Calculation Method 2, annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated according to § 98.233(dd)(2).
W	§ 98.236(dd)(3)(iv)	For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, total annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated from summing the annual CH_4 emissions calculated from § 98.233(dd)(3)(iii)(E) and § 98.233(dd)(3)(iv)(C).
W	§ 98.236(ee)(1)(ii)	The total number of reciprocating internal combustion engines with crankcase vents.
W	§ 98.236(ee)(1)(iii)	The total number of reciprocating internal combustion engines with crankcase vents that operated and were vented directly to the atmosphere.
W	§ 98.236(ee)(1)(iv)	The total number of reciprocating internal combustion engines with crankcase vents that operated and were routed to a flare.
W	§ 98.236(ee)(1)(v)	The total number of reciprocating internal combustion engines with crankcase vents that were in a manifolded group containing a compressor vent source with emissions reported under paragraphs (o) or (p) of this section.
W	§ 98.236(ee)(2)(i)(A)	For each measurement performed on a crankcase vent, well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).
W	§ 98.236(ee)(2)(i)(B)	For each measurement performed on a crankcase vent, unique name or ID for the reciprocating internal combustion engine.
W	§ 98.236(ee)(2)(i)(C)	For each measurement performed on a crankcase vent, measurement date.
W	§ 98.236(ee)(2)(i)(D)	For each measurement performed on a crankcase vent, measurement method (either the screening method if emissions were not detected or the method subsequently used to measure the volumetric emissions if detected using a screening method).
W	§ 98.236(ee)(2)(i)(E)	For each measurement performed on a crankcase vent, measured flow rate, in standard cubic feet per hour.

Subpart	Citation in 40 CFR Part 98	Data Element Description
W	§ 98.236(ee)(2)(i)(F)	For each measurement performed on a crankcase vent, if the measurement is for a manifolded group of crankcase vent sources, indicate the number reciprocating internal compressor engines that were operating during measurement.
W	§ 98.236(ee)(2)(ii)	For reciprocating internal combustion engines with crankcase vents that calculate emissions according to § 98.233(ee)(1), annual CH_4 emissions from the reciprocating internal combustion engine crankcase vent, in metric tons CH_4.
W	§ 98.236(ee)(3)(i)	For reciprocating internal combustion engines with crankcase vents that calculate emissions according to § 98.233(ee)(2), well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

BILLING CODE 6560–50–C

In a handful of cases, the EPA has made minor revisions to data elements in this final action as compared to the proposed data element included in the 2023 Subpart W Proposal. For certain proposed data elements, we have revised the citations from proposal to final. In other cases, the minor revisions include clarifications to the text. The EPA evaluated these data elements and how they have been clarified in the final rule to verify that the information collected has not substantially changed since proposal. These data elements are listed in Table 6 of the memorandum, *Confidentiality Determinations and Emission Data Designations for Data Elements in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems,* available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. Because the information to be collected has not substantially changed in a way that would affect the confidential nature of the information to be collected from the proposal, we are finalizing the confidentiality determinations or emission data designations for these data elements as proposed. For additional information on the rationales for the confidentiality determinations for these data elements, see the preamble to the 2023 Subpart W Proposal and the memorandum, *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems,* available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

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

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

The EPA is finalizing the confidentiality determination as it was proposed for the one subpart W data reporting element for which no determination has been previously established. The EPA received no comments on the proposed determination. Please refer to the preamble to the 2023 Subpart W Proposal for additional information regarding the proposed confidentiality determination.

C. Final Reporting Determinations for Inputs to Emissions Equations

In the 2023 Subpart W Proposal, the EPA proposed to assign several data elements to the ‘‘Inputs to Emission Equation’’ data category. As discussed in section VI.B.1. of the 2022 Proposed Rule (87 FR 36920, June 21, 2022), the EPA determined that the Argus Leader decision does not affect our approach for handling of data elements assigned to the ‘‘Inputs to Emission Equations’’ data category. Data assigned to the ‘‘Inputs to Emission Equations’’ data category are assigned to one of two subcategories, including ‘‘inputs to emission equations’’ that must be directly reported to the EPA, and ‘‘inputs to emission equations’’ that are not reported but are entered into the EPA's IVT. The EPA received no comments specific to the proposed reporting determinations for inputs to emission equations in the proposed rules. Additional information regarding these reporting determinations may be found in section V.C. of the preamble to the 2023 Subpart W Proposal.

The EPA is not finalizing the proposed reporting determinations for certain data elements in subpart W because the EPA is not taking final action on the requirements to report these data elements at this time (see section III. of this preamble for additional information). These data elements are listed in Table 2 of the memorandum, *Reporting*

Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems, available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

In some cases, the EPA is finalizing revisions that include new data elements that the EPA did not propose to assign to the ''Inputs to Emission Equations'' data category. These data elements are listed in Table 3 of the memorandum, *Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems*, available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. Because the EPA has not proposed or solicited public comment on an inputs determination for these data elements, we are not finalizing reporting determinations for these data elements at this time.

In a handful of cases, the EPA has made minor revisions to data elements assigned to the ''Inputs to Emissions Equations'' category in this final action as compared to the proposed data element included in the 2023 Subpart W Proposal. For certain proposed data elements, we have revised the citations from proposal to final. In other cases, the minor revisions include clarifications to the text. The EPA evaluated these inputs to emissions equations and how they have been clarified in the final rule to verify that the data element has not substantially changed since proposal. These data elements and how they have been clarified in the final rule are listed in Table 4 of the memorandum, *Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in the 2024 Final Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems*, available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. Because the input has not substantially changed since proposal, we are finalizing the proposed reporting determinations for these data elements as proposed. For additional information on the rationale for the reporting determinations for the data elements, see the preamble to the 2023 Subpart W Proposal and 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 for Petroleum and Natural Gas Systems*, available in the docket for this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234).

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

VI. Impacts of the Final Amendments

This section summarizes the impacts related to the specific substantive final amendments for subpart W (as well as subparts A and C), as generally described in section II. of this preamble. Major changes to the impacts analysis for the final rule as compared to the impacts analysis for the proposed revisions are identified in this section. Total costs have increased from $92.3 million per year at proposal to $183.6 million per year at final due to underestimates at proposal in the labor hours needed to comply with these amendments. As described in section II. of this preamble, for some proposed revisions, we are not taking final action on revisions to calculation, monitoring, or reporting requirements that would have required reporters to collect or submit additional data. Therefore, the final burden for these sources have been revised to reflect only those requirements that are being finalized. For example, as discussed in section II.N. of this preamble, the proposed revision to require continuous parameter monitoring for flares is not being finalized, resulting in the reduction of capital costs by $19.1 million as compared to the proposal's cost analysis.

The EPA also received a number of comments on the proposed revisions and the impacts of the proposed revisions. Following consideration of these comments, the EPA has, in some cases, revised the final rule requirements and updated the impacts analysis to reflect these changes. The summary of the final amendments impacts is followed by a summary of the major comments on the proposed amendments impacts and the EPA's responses to those comments. The document *Summary of Public Comments and Responses for 2024 Final Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems under the Greenhouse Gas Reporting Rule*, available in the docket to this rulemaking (Docket ID. No. EPA–HQ–OAR–2023–0234), contains the full text of all the comments on impacts of the 2023 Subpart W Proposal, including the major comments responded to in this preamble.

A. Cost Analysis

1. Summary of Cost Analysis for Final Amendments

The revisions will amend requirements that apply to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule consistent with CAA section 136(h) to ensure that reporting under subpart W is based on empirical data and accurately reflects total CH_4 emissions and waste emissions from applicable facilities, and to allow owners and operators of applicable facilities to submit empirical emissions data that appropriately could demonstrate the extent to which a charge is owed in future implementation of CAA section 136. These revisions include improving the existing calculation, recordkeeping, and reporting requirements. Note that one proposed revision to require continuous parameter monitoring for flares is not being finalized, resulting in the reduction of capital costs by $19.1 million.

The EPA is finalizing 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 for new emission sources and address potential gaps in reporting, and revisions to collect data that will 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 finalizing revisions that will improve implementation of the program, such as those that will 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 revisions to improve accuracy of reporting will increase costs for reporters.

As discussed in section V. of this preamble, we are implementing some of these provisions beginning in RY2024 and some beginning in RY2025. The amendments for requirements for which reporters would incur costs will be effective beginning in RY2025. Costs have been estimated over the three years following the year of implementation. The incremental implementation costs for each reporting year are summarized in table 7 of this preamble. The estimated annual average labor burden is $169.4 million per year and the annual average labor burden per reporter is $55,100. The incremental burden for subpart W and the incremental costs per reporter are shown in table 7 of this preamble.

TABLE 7—TOTAL INCREMENTAL LABOR BURDEN FOR REPORTING YEARS 2025–2027

[$2021/year]

Cost summary	RY2025	RY2026	RY2027	Annual average
Burden by Year	$169.4 million	$169.4 million	$169.4 million	$169.4 million.
Number of Reporters	3,077	3,077	3,077	3,077.
Incremental Labor Cost per Reporter	$55,100	$55,100	$55,100	$55,100.

There is an additional annualized incremental burden of $14.1 million for operation and maintenance (O&M) costs, which reflects changes to applicability and monitoring. Including capital and O&M costs, the total annual average burden is $183.6 million over the next 3 years.

The total incremental burden and burden by reporter per subpart W industry segment are shown in table 8 of this preamble.

TABLE 8—TOTAL INCREMENTAL BURDEN BY INDUSTRY SEGMENT AND BY REPORTER

[$2021/year] [a]

Industry segment	Count of reporters [b]	Labor costs [c]	Capital and O&M (annualized)	Total annual cost	Total annual cost per reporter
Onshore Petroleum and Natural Gas Production	777	$142,067,784	$3,693,563	$145,761,348	$187,595
Offshore Petroleum and Natural Gas Production	141	3,922	0	3,922	28
Onshore Petroleum and Natural Gas Gathering and Boosting	361	10,767,359	1,319,919	12,087,278	33,483
Onshore Natural Gas Processing	515	11,873,365	2,776,745	14,650,110	28,447
Onshore Natural Gas Transmission Compression	1,008	4,064,345	5,891,787	9,956,131	9,877
Natural Gas Transmission Pipeline	53	89,867	187	90,054	1,699
Underground Natural Gas Storage	68	319,173	370,275	689,448	10,139
LNG Import and Export Equipment	11	51,729	26,350	78,079	7,098
LNG Storage	7	29,922	24,890	54,812	7,830
Natural Gas Distribution	164	179,491	0	179,491	1,094
Petroleum and Natural Gas Systems (all segments)	3,077	169,446,957	14,103,716	183,550,673	59,652

[a] Includes estimated increase in costs following implementation of revisions in RY2025.

[b] Counts are based on GHGRP data reported in RY2020 and 567 new facilities, as detailed in the memorandum, *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems.*

[c] Initial year and subsequent year labor costs are $169.4 million per year.

A full discussion of the cost and burden impacts may be found in the memorandum, *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. As described further in section VI.B. of this preamble, the national total annual costs of the final rule reflect the fact that there are a large number of affected entities, but per entity costs and impacts are low. Considering the improvements to the GHGRP contained in this final rule as well as the need to comply with CAA section 136(h) and the anticipated costs of this rule in the context of this industry, the EPA concludes that the anticipated costs are reasonable and support the final rule.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed cost impacts.

Comment: Multiple commenters disagreed with the cost estimates related to changing the reporting of total emissions at the basin level to reporting total emissions at the well-pad level (for Onshore Petroleum and Natural Gas Production) or gathering and boosting site level (for Onshore Petroleum and Natural Gas Gathering and Boosting). The commenters estimated costs that were 8 times higher than the EPA's costs for Onshore Petroleum and Natural Gas Production reporting and 15 times higher than the EPA's costs for Onshore Petroleum and Natural Gas Gathering and Boosting reporting.

Response: Based on consideration of the commenter's cost analysis, the EPA reassessed the costs for these proposed changes. After consideration of the large amount of administrative burden shown by the commenters, the EPA determined it was appropriate to increase the estimated level of burden and associated costs. The relevant cost analysis in the proposal was based only on the number of facilities, without taking into consideration the number of wells per well-pad per Onshore Petroleum and Natural Gas Production facility and the number of sites per Onshore Petroleum and Natural Gas Gathering and Boosting facility. The labor hours were increased from 15 hours at proposal to 90 hours at final for the Onshore Petroleum and Natural Gas Production industry segment and from 5 hours at proposal to 45 hours at final for the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. As a result, in the EPA's final amendments cost analysis, these costs have increased from $1.0 million total for both industry segments in the proposal to $6.5 million total for both industry segments. For more information, see the information collection request (ICR) document OMB No. 2060–0751 (EPA ICR number 2774.02) and *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems.*

Comment: One commenter noted that the cost analyses related to the determination of fuel consumption through fuel records in order to incorporate combustion slip into their emissions was underestimated. The commenter argued that the costs should be based on the number of well-pads or sites instead of the number of facilities and that the level of effort should be increased from 30 minutes to one hour.

Response: The costs analysis relevant here in the proposal was based only on the number of facilities, without taking into consideration the number of wells per well-pad per Onshore Petroleum and Natural Gas Production facility and the number of sites per Onshore Petroleum and Natural Gas Gathering and Boosting facility. In the EPA's final amendments cost analysis, these costs have increased from $50,000 total for both industry segments to $9.2 million total for the three applicable industry segments. Costs were updated based on the number of well-pads or sites instead of the number of facilities and the labor estimate was increased from 30 minutes per facility to one hour per well-pad or site for the Onshore Petroleum and Natural Gas Production industry segment and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment. The labor estimate was increased from 30 minutes per facility to one hour per facility for the Natural Gas Distribution industry segment. In the final impacts analysis we also changed the characterization of combustion slip from a new emission source to a change in requirements. For more information, see ICR document OMB No. 2060–0751 (EPA ICR number 2774.02) and *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems.*

Comment: One commenter noted that the cost analyses related to the proposed revisions to 40 CFR 98.36(c)(1) and (3) did not include burden for the industry segments that have previously reported their combustion emissions to subpart C. The commenter stated that the proposed revisions clarify that reporters must separately report equipment type within the same aggregation of units or common pipe configuration. According to the commenter, there is significant burden to change from the aggregation/common pipe methods in subpart C to the methods within subpart W. The commenter stated that the costs should be at least 2 hours per year per each aggregation of units/common pipe reported under subpart C.

Response: As noted by the commenter, costs for this revision were inadvertently excluded from the impacts analysis in the proposal. After review of commenter's suggestions, the costs have been incorporated using the suggested burden, and we included the average number of aggregations reported to Subpart C for each of the five affected industry segments (Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Import and Export Equipment, and LNG Storage). Costs were calculated assuming 10 hours per facility per year, or 2 hours per aggregation of units/common pipe reported under subpart C and an average of five aggregations per facility based on subpart C data. In the EPA's final amendments cost analysis, these costs have increased to $1.7 million total for the five affected industry segments. For more information, see ICR document OMB No. 2060–0751 (EPA ICR number 2774.02) and *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems.*

Comment: Two commenters noted that the cost analyses related to the proposed revisions to 40 CFR 98.233(n)(2) did not include burden to account for the monthly visual inspections required for flares that are not equipped with continuous pilot light monitoring.

Response: As noted by the commenter, costs for this revision were inadvertently excluded from the impacts analysis in the proposal. After review of commenter's suggestions, the costs have been incorporated. Assuming that a technician will inspect each flare once per month, costs have been updated to $870,000 for Onshore Natural Gas Processing, $23,000 for Onshore Natural Gas Transmission Compression, $25,000 for Underground Natural Gas Storage, $31,000 for LNG Import and Export Equipment, $4.9 million for Onshore Petroleum and Natural Gas Gathering and Boosting, and $53.5 million for Onshore Petroleum and Natural Gas Production. Overall costs increased by $59.4 million from proposal to final.

For more information, see ICR document OMB No. 2060–0751 (EPA ICR number 2774.02) and *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems.*

Comment: One commenter noted that the cost analyses related to the requirement to inspect dump valves was based on the number of malfunctioning dump valves in each industry segment instead of the number of tanks in each industry segment.

A second commenter noted that malfunctioning dump valves on atmospheric storage tanks were incorrectly categorized as new emission sources even though dump valves are currently reported under the GHGRP with different requirements.

Response: As noted by the commenter, costs for this revision were inadvertently based on the number of malfunctioning dump valves in one reporting year instead of the number of dump valves that must be inspected. Changes were made to the costs related to dump valve inspections, assuming one dump valve per tank and using the count of tanks for each industry segment. Costs in the final rule impacts analysis are $4.2 million for Onshore Petroleum and Natural Gas Production, $650,000 for Onshore Petroleum and Natural Gas Gathering and Boosting and $920,000 for Onshore Natural Gas Processing. The overall costs increased by $5.7 million from proposal to final.

For more information, see ICR document OMB No. 2060–0751 (EPA ICR number 2774.02) and *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems.*

In response to the second commenter, the final impacts analysis changed the characterization of malfunctioning dump valves from a new emission source to a change in requirements.

B. Cost-to-Revenue Ratio Analysis

To further assess the economic impacts of the final rule, the EPA revised from proposal its screening analysis comparing the estimated total annualized compliance costs for the petroleum and natural gas systems industry segments with industry mean cost-to-revenue ratios based on the total facility costs that are applicable to parent entities in each segment in the final rule. This analysis shows that the per-entity impacts within each industry segment are low. These low mean cost-to-revenue ratios indicate that the final rule is unlikely to result in significant changes in parent entity production decisions or other choices that would result in significant fluctuations in prices or quantities in affected markets.

TABLE 9—MEAN CRRS FOR PARENT ENTITIES BY INDUSTRY SEGMENT, ALL BUSINESS SIZES

Industry segment	Mean CRR (standard error)
Onshore petroleum and natural gas production	1.71% (1.63–1.80%)
Offshore petroleum and natural gas production	0.02% (0.01–0.02%)
Onshore petroleum and natural gas gathering and boosting	0.90% (0.82–0.99%)
Onshore natural gas processing	0.71% (0.61–0.81%)
Onshore natural gas transmission compression	0.39% (0.30–0.48%)
Onshore natural gas transmission pipeline	0.36% (0.22–0.49%)
Underground natural gas storage	0.01% (0.01–0.01%)
LNG import and export equipment	0.02% (0.01–0.03%)
LNG storage	0.00% (0.00–0.00%)
Natural gas distribution	0.17% (0.11–0.23%)
All segments	1.05% (1.00–1.10%)

CRR = cost-to-revenue ratio.

The EPA also evaluated the mean costs to individual facilities and mean costs to parents (accounting for multiple owned facilities) for reporters (shown in table 10 of this preamble), which are relatively small given the high revenues of parent companies within the petroleum and natural gas systems sector. There are currently 2,322 existing facilities reporting to subpart W that are owned by approximately 600 parent entities. Based on a review of revenue data available for approximately 587 parent entities, the final rule costs represent less than one percent of the total annual revenue for parent entities that would be reporting under subpart W.

TABLE 10—ESTIMATED MEAN COSTS AND REVENUES FOR FACILITY AND PARENT ENTITIES, ALL SEGMENTS

Metric	Estimated values (95% confidence interval)
Mean cost to parent entity per facility (thousands) [a]	$43.1 ($42.8–$43.3)
Mean number of facilities owned per parent	4.6
Mean cost to parent for all associated facilities (thousands) [a]	$201.8 ($196.1–$207.5)
Mean parent entity revenue (billions) [a]	$11.70 ($10.90–$12.50)
Total revenue for all subpart W parents (trillions)	$8.82 ($8.22–$9.42)
Mean CRR for parent entities, using all facility costs [b]	1.05% (1.00–1.10%)

[a] Average across all existing and new reporters.
[b] Because parent revenues are heavily skewed towards higher revenues, the ratio of mean cost to mean revenue (which is approximately 0.0004%) differs substantially from the mean cost-to-revenue ratio (which is approximately 1.05%).

The EPA has also assessed the potential benefits of the final amendments to subpart W. The implementation of the final rule will provide numerous benefits for stakeholders, the Agency, industry, and the general public. The final revisions strengthen the empirical basis for and scope of reporting under subpart W so that reporting is based on empirical data accurately reflects total CH_4 emissions and waste emissions from applicable facilities. These revisions include improvements to the calculation, monitoring, and reporting requirements, including updates to existing emission factors and emissions estimation methodologies, revisions to require reporting of additional data for new emission sources and address potential gaps in reporting, and revisions to collect data that will 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 revisions will maintain and improve the quality of the data collected under part 98 where continued collection of information assists in evaluation and support of EPA programs and policies under provisions of the CAA.

Because this is a final reporting rule, the EPA did not quantify estimated emission reductions or monetize the benefits from such reductions that could be associated with this action. The benefits of the final amendments are based on their relevance to policy making, transparency, and market efficiency. The final amendments to the reporting system for petroleum and natural gas systems will benefit the EPA, other policymakers, and the public by increasing the completeness and accuracy of facility emissions data. Public data on emissions allows for accountability of emitters to the public. Improved facility-specific emissions data will aid local, state, and national policymakers as they evaluate and consider future climate change policy decisions and other policy decisions for criteria pollutants, ambient air quality standards, and toxic air emissions. The benefits of improved reporting of petroleum and natural gas systems GHG emissions to government also include enhancing existing programs, such as the Natural Gas STAR Program, that provide significant benefits, such as identifying cost-effective technologies and practices to reduce emissions of CH_4 from operations in all of the major industry sectors—production, gathering and processing, transmission, and distribution. The Natural Gas STAR program leverages GHGRP reporting data to track partner petroleum and natural gas company activities related to their Methane Challenge commitments. The final changes to subpart W will increase knowledge of the location and magnitude of significant CH_4 emissions sources in the petroleum and natural gas industry, and associated activities and technologies, which can result in improvements in technologies and the identification of new emissions reducing technologies.

Benefits to industry of improved GHG emissions monitoring and reporting under the proposed amendments include the value of having verifiable empirical data to present to the public to demonstrate appropriate environmental stewardship, and a better understanding of their emission levels and sources to identify opportunities to reduce emissions. The EPA also anticipates that improvements to monitoring and implementation of empirical measurement methods will result in emissions reductions. Based on activity data used to inform the U.S. GHG Inventory, the EPA estimated approximately 403.4 billion cubic feet of fugitive CH_4 emissions (including fugitive leaks, venting, and flaring) in 2021, representing a potential loss of over $871 million [88] to industry. To the extent that more frequent monitoring helps to identify and mitigate emissions from leakage, a robust reporting program based on empirical data can help industry demonstrate and disseminate their environmental achievements. Businesses and other innovators can use the data to determine and track their GHG footprints, find cost-saving efficiencies that reduce GHG emissions and save product, and foster technologies to protect public health and the environment and to reduce costs associated with fugitive emissions. Such monitoring also allows for inclusion of standardized GHG data into environmental management systems, providing the necessary information to track actual company performance and to demonstrate and disseminate their environmental achievements. Once facilities invest in the institutional knowledge and systems to monitor and report emissions, the cost of monitoring should fall and the accuracy of the accounting should continue to improve. The final amendments will continue to allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry and achieve and disseminate information about their environmental performance.

In addition, transparent public data on emissions allows for accountability of polluters to the public who bear the cost of the pollution. The GHGRP serves as a powerful data resource and provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments. GHGRP data are easily accessible to the public via the EPA's online data publication tool, also known as FLIGHT (Facility Level Information on Greenhouse gases Tool) at: *https://ghgdata.epa.gov/ghgp/main.do.* FLIGHT is designed for the general public and allows users to view and sort GHG data from over 8,000 entities in a variety of ways including by location, industrial sector, and type of GHG emitted, and includes demographic data. Although the emissions reported to the EPA by reporting facilities are global pollutants, many of these facilities also release pollutants that have a more direct and local impact in the surrounding communities. Citizens, community groups, and labor unions have made use of public pollutant release data to negotiate directly with emitters to lower emissions, avoiding the need for additional regulatory action.

The publicly available data generated by this final rule may be of particular interest to environmental justice communities. The EPA has previously engaged with representatives of communities with environmental justice concerns and heard directly from stakeholders regarding the health effects of air pollution associated with oil and gas facilities, the implications of climate change and associated extreme weather events for health and well-being in overburdened and vulnerable communities, and accessibility to data and information regarding sources near environmental justice communities. The data generated in this final reporting rule can be used to inform community residents or other stakeholders as they search for information about pollution that affects them, and may provide vital pollutant release data that is needed for advocates to push for stronger protections within their communities. This final rule substantially improves the data reported and made available to environmental justice communities by improving the accuracy, completeness, and relevance of the data to community members. Specifically, the disaggregation of reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to at least the well-pad and gathering boosting site-level, respectively, will provide communities with more localized information on GHG emissions from these segments that may impact their localities. Such information has previously been unavailable to affected environmental justice communities. Additionally, the final amendments will improve the quality and transparency of reported data to affected communities, for example, by providing data on other large release events, including the location, description, and volume of pollutants released. This final rule also requires reporting of data related to facilities that receive super-emitter event notifications, including the type of event resulting in the emissions and an indication of whether the emissions are included and reported under subpart W. This information provides transparency and accountability for large emissions releases and provides important data for impacted individuals, particularly in environmental justice communities.

Therefore, while the EPA has not quantified the benefits of these amendments to subpart W, the agency believes that they will be substantial, and further support a conclusion that the rule is reasonable and worthwhile. In addition, the focus on strengthening the empirical basis of the data that is the foundation of this final rule was mandated by Congress in the IRA.

VII. 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'' as defined in Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. The EPA prepared an analysis of the potential impacts associated with this action. This analysis, *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, is also available in the docket to this rulemaking and is briefly summarized in section VI. of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned OMB Number 2060–0751 (EPA ICR number 2774.02). You can find a copy of the ICR in the docket for this rule and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The EPA estimates that the amendments will result in an increase in burden. The burden associated with the final rule is due to revisions that will expand reporting to include new emission sources or that expand the industry segments covered by existing emissions sources and that may impact

[88] Based on natural gas prices from EIA (current monthly average, April 2023). See *https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.*

the facilities that are required to report to subpart W; revisions to emissions calculation methodologies that will require additional monitoring; and revisions to collect additional data to more accurately reflect and verify total CH_4 emissions in reports submitted to the GHGRP or to provide information for future implementation of the waste emissions charge under CAA section 136. As a result of these revisions, 567 new sources are expected to become subject to subpart W. Labor and O&M costs are included for those new sources to comply with the reporting and recordkeeping costs detailed in EPA ICR number 2300.18, as well as costs to comply with these revisions.[89]

The estimated annual average burden is 1,902,792 hours and $183.6 million (per year) over the 3 years covered by this information collection. Further information on the EPA's assessment on the impact on burden can be found in the memorandum, *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234.

Respondents/affected entities: Owners and operators of petroleum and natural gas systems 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 sections 114 and 136.

Estimated number of respondents: 3,077 (affected by final amendments).

Frequency of response: Annually.

Total estimated burden: 1,902,792 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $183.6 million, (per year), includes $14.1 million annualized 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. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses in the petroleum and natural gas industry. Small entities include small businesses, small organizations, and small governmental jurisdictions. The EPA has determined that some small entities are affected because their production processes emit GHGs that must be reported.

In the implementation of the GHGRP, the EPA previously determined thresholds that reduced the number of small businesses reporting. For example, petroleum and natural gas facilities generally only report to part 98 if all combined emissions from the facility, including stationary fuel combustion and other applicable manufacturing source categories, exceed 25,000 $mtCO_2e$ per year. However, facilities from the Onshore Petroleum and Natural Gas Production, Natural Gas Distribution, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline industry segments must report if specific petroleum and natural gas emissions sources from these operations emit 25,000 $mtCO_2e$ or more per year. These thresholds are intended to exclude smaller enterprises that, generally, are not significant emissions sources. The EPA estimates that in most cases, smaller enterprises have very small operations (such as a single family owning a few production wells) that are unlikely to cross the 25,000 $mtCO_2e$ reporting threshold. The final revisions will not revise the threshold for existing subpart W reporters, therefore, we do not expect a significant number of small entities will be newly impacted under the final rule revisions.

The amendments apply to 2,322 existing facilities and 567 new facilities that result from rule revisions that require the reporting of new emission sources or that expand the industry segments covered. The rule amendments predominantly apply to existing reporters and are amendments that will expand reporting to include new emission sources; add, remove, or refine emissions estimation methodologies to improve the accuracy and transparency of reported emission data; for the Onshore Natural Gas Production and Onshore Natural Gas Gathering and Boosting segments, revise reporting of emissions from a basin level to a site level; implement requirements to collect new or revised data; clarify or update provisions that have been misinterpreted; or streamline or simplify requirements by increasing flexibility for reporters or removing redundant requirements.

The EPA conducted a small entity analysis that assessed the costs and impacts to small entities, including: (1) Revisions to add new emissions sources and expand the industry segments covered by existing emissions sources, (2) changes to improve existing monitoring or calculation methodologies, and (3) revisions to reporting and recordkeeping requirements for data provided to the program. The Agency anticipates that although a subset of small entity reporters (160–180) have a cost-to-revenue ratio (CRR) > 1%, there are only a limited number (73–75) of small entities, primarily in the very small business size range (1–19 employees), that would be likely to have significant impacts with CRR > 3%, reflecting a small proportion (6.3%–14.0%) of the total affected small entities. The mean CRR for these very small entities (1–19 employees) is estimated to be between 2.19% (2.11–2.28%) and 3.79% (3.47–4.11%) based on the incremental costs for existing reporting entities and between 2.78% (2.63–2.92%) and 4.79% (4.28–5.31%) based on the costs for newly reporting entities.[90] Details of this analysis are presented in the memorandum, *Assessment of Burden Impacts for Greenhouse Gas Reporting Rule Revisions for Petroleum and Natural Gas Systems*, available in the docket for this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. Based on the results of this analysis, we have concluded that this action is not likely to have a significant regulatory burden for a substantial number of small entities and thus that this action will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more (adjusted annually for inflation) as described in UMRA, 2 U.S.C. 1531–1538, for state, local, and tribal governments, in the aggregate, or the

[89] In addition to the costs to comply with these revisions, the 567 new sources will also incur the average subpart W reporter-level labor and O&M costs, which differ by industry segment, from OMB Number 2060–0629 (EPA ICR number 2300.18) to comply with the subpart W requirements that were in place prior to these revisions.

[90] The EPA conducted a multi-level analysis to estimate mean CRRs for multiple scenarios. The mean CRR and associated 95-percent confidence intervals provide an estimate of the range of cost-to-sales rtios expected to apply to affected very small entities that would be expected in the total population.

private sector in any one year, and does not significantly or uniquely affect small governments. The costs involved in this action are estimated not to exceed $100 million or more (adjusted for inflation, with the current threshold of approximately $198 million) in any one year. The yearly costs of this final action are presented in tables 7 and 8 of this preamble. The action in part implements mandate(s) specifically and explicitly set forth in CAA section 136.

This final rule does not apply to governmental entities unless the government entity owns a facility in the petroleum and gas industry that directly emits GHG above part 98 applicability threshold levels. It does not impose any implementation responsibilities on state, local, or tribal governments and it is not expected to increase the cost of existing regulatory programs managed by those governments. Thus, the impact on governments affected by the final rule is expected to be minimal.

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. This final rule does not apply to governmental entities unless the government entity owns a facility in the petroleum and gas industry (*e.g.*, an LDC) that directly emits GHG above part 98 applicability threshold levels. Therefore, the EPA anticipates relatively few state or local government facilities will be affected.

However, consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA sought comments from small governments concerning the regulatory requirements that might significantly or uniquely affect them in the development of the final rule. Specifically, the EPA previously published an RFI seeking public comment in a non-regulatory docket to collect responses to a range of questions related to the Methane Emissions Reduction Program, including subpart W revisions (see Docket ID. No. EPA–HQ–OAR–2022–0875). The EPA received two comments from government entities supporting the use of empirical data and improvements to the accuracy of calculation methods under subpart W. The EPA also solicited comments on the 2023 Subpart W Proposal; the EPA did not receive any comments regarding concerns that this rule will significantly or uniquely affect small governments. All comments were considered during the development of the final rule.

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

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized Tribal governments, nor preempt tribal law. This regulation will apply directly to petroleum and natural gas facilities that may be owned by tribal governments that emit GHGs. However, it will generally only have tribal implications where the tribal entity owns a facility that directly emits GHGs above threshold levels; therefore, relatively few tribal facilities will be affected. Of the subpart W facilities currently reporting to the GHGRP in RY2021, we identified four facilities currently reporting to part 98 that are owned by one tribal parent company. In addition to tribes that will be directly impacted by the final revisions due to owning a facility subject to the requirements, the EPA anticipates that tribes could be impacted in cases where facilities subject to the final revisions are located on Tribal land. In particular, the EPA reviewed the location of the production wells reported by facilities under the Onshore Petroleum and Natural Gas Production segment and found production wells reported under subpart W on lands associated with approximately 20 tribes.

Therefore, although the EPA anticipates that only one tribe will be directly subject to the rule, the EPA took a number of steps to provide information, consult with, and obtain input from tribal governments and representatives during the development of the rule. On November 4, 2022, the EPA published an RFI seeking public comment on a range of questions related to the Methane Emissions Reduction Program, including subpart W revisions (see Docket ID. No. EPA–HQ–OAR–2022–0875). The EPA received one comment from a tribal entity relevant to subpart W. The commenter supported the use of empirical data and improvements to the accuracy of calculation methods under subpart W, including the use of advanced CH_4 detection technologies for leak surveys at well sites and compressor stations; these comments were considered during the development of the rule. The EPA further consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation, to permit them to have meaningful and timely input into its development. On July 11, 2023, the EPA invited all 574 federally-recognized Tribes, Alaska Native Villages, and Alaska Native Corporations, to consult on the proposed revisions at a date and time developed in consultation with Tribes requesting consultation, with an anticipated consultation timeline of September 4, 2023; a copy of this letter is available in the docket to this rulemaking, Docket ID. No. EPA–HQ–OAR–2023–0234. Only one Tribe participated in government-to-government consultation with the EPA. In response, the EPA met with the Ute Indian Tribe's Business Committee via video conference at 3:30 p.m. Eastern Time on September 20, 2023. The EPA provided several other opportunities for tribal input; the EPA opened the rule for public comment from August 1 to October 2, 2023, and hosted a virtual public hearing for the proposed revisions on August 21, 2023. The EPA provided a subsequent informational webinar on the technical aspects of the rule on September 7, 2023. The EPA has considered the tribal input from the coordination and consultation calls, informational webinar, and public comments in the development of the final rule.

As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the executive order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

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 regarding revisions to reporting requirements 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 final amendments will expand reporting to include new emission sources; add, remove, or refine emissions estimation methodologies; improve the accuracy and transparency of reported emission data; for the Onshore Natural Gas Production and Onshore Natural Gas Gathering and Boosting segments, revise reporting of emissions from a basin level to a site level; implement requirements to collect new or revised data; clarify or update provisions that have been misinterpreted; or streamline or simplify requirements by increasing flexibility for reporters or removing redundant requirements. We are also finalizing revisions that streamline or simplify requirements or alleviate burden through revision, simplification, or removal of certain calculation, monitoring, recordkeeping, or reporting requirements. In general, these changes will not have a significant, adverse effect on the supply, distribution, or use of energy. In addition, the EPA is finalizing confidentiality determinations for new and revised data elements included in this rulemaking and for certain existing data elements for which a confidentiality determination has not previously been finalized. These amendments and confidentiality determinations do not make any changes to the existing monitoring, calculation, and reporting requirements under subpart W and are not likely to have a significant adverse effect on 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 has decided to incorporate by reference several standards in establishing monitoring requirements in these final amendments.

For enclosed combustion devices, the EPA is finalizing a requirement to conduct a performance test to use the Tier 2 destruction efficiency and combustion efficiency. The test must be conducted in accordance with 40 CFR 60.5413b(b) or (d) or using EPA Other Test Method 52 (OTM–52), *Method for Determination of Combustion Efficiency from Enclosed Combustors Located at Oil and Gas Production Facilities*, dated September 26, 2023. In OTM–52, a gas sample is continuously extracted from the exhaust duct of an enclosed combustion device and conveyed to a gas analyzer(s) for determination of CO_2, CO, and hydrocarbon concentrations for the calculation of combustion efficiency. Anyone may access OTM–52 at *https://www.epa.gov/emc/emc-other-test-methods*. This standard is available to everyone at no cost; therefore, the method is reasonably available for reporters.

For facilities that conduct a performance test to calculate combustion slip, the EPA is finalizing a requirement that the performance test will be conducted in accordance with one of the test methods in 40 CFR 98.234(i), which include EPA Methods 18 and 320 as well as an alternate method, ASTM D6348–12 (Reapproved 2020), *Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy*, Approved December 1, 2020. The EPA is allowing the use of the alternate method ASTM D6348–12, which is based on the use of a Fourier transform infrared (FTIR) spectrometer for the identification and quantification of multicomponent gaseous compounds in stationary source effluent, in lieu of EPA Method 320. The EPA currently allows for the use of an earlier version of this method, ASTM D6348–03, under other subparts of part 98, including subparts I (Electronics Manufacturing), V (Nitric Acid Production), and OO (Fluorinated Gas Production), for the quantification of other GHGs. Therefore, the EPA is allowing ASTM D6348–12 to be used in subpart W to quantify CH_4 emissions from combustion slip. Anyone may access the standard ASTM D6348–12 on the ASTM website (*https://www.astm.org/*) for additional information. The standard is available to everyone at a cost determined by the ASTM ($76). The ASTM also offers memberships or subscriptions that allow unlimited access to their methods. The cost of obtaining these methods is not a significant financial burden, making the methods reasonably available for reporters. The EPA will also make a copy of these documents available in hard copy at the appropriate EPA office (see the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information) for review purposes only.

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

Because this is an information collection and reporting rule, it does not directly affect human health or environmental conditions and therefore the EPA cannot evaluate potentially disproportionate and adverse effects on communities with environmental justice concerns. Although this action does not directly affect human health or environmental conditions, we expect it will affect environmental justice concerns by greatly improving the availability, accuracy, and relevance of information about pollution in their communities.

The EPA has developed improvements to the GHGRP in the final rule that benefit the public, including environmental justice communities, by increasing the completeness and accuracy of facility emissions data. The data that will be collected through this action will provide an important data resource for communities and the public to understand GHG emissions. Although the emissions reported to the EPA by reporting facilities are global pollutants, many of these facilities also release pollutants that have a more direct and local impact in the surrounding communities. Since facilities will be required to use prescribed calculation and monitoring methods, emissions data can be compared and analyzed, including locations of emissions sources. GHGRP data are easily accessible to the public via the EPA's online data publication tool (FLIGHT), available at: *https://ghgdata.epa.gov/ghgp/main.do*. FLIGHT allows users to view and sort GHG data for every reporting year starting with 2010 from over 8,000 entities in a variety of ways including by location, industrial sector, and type of GHG emitted, and provides supplementary demographic data that may be useful to communities with environmental justice concerns. This powerful data resource provides a critical tool for communities to identify nearby sources of GHGs, including methane and nitrous oxide, and to provide information to state and local governments. The EPA believes that the transparency provided by the data reported under these final revisions will ultimately encourage and result in reduction of GHG emissions and other co-pollutants, such as hazardous air pollutants and volatile organic compounds.

The final revisions to part 98 include requirements for reporting of GHG data from additional emission sources (other large release events, nitrogen removal units, produced water tanks, crankcase venting, and mud degassing), improvements to emissions calculation methodologies, and collection of data to support verification of GHG emissions and transparency. The disaggregation of reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to at least the well-pad and gathering boosting site-level, respectively, and the required reporting of geographical coordinates for other large release events, will provide communities with additional, more localized information on GHG emissions from these segments. Overall, these revisions will improve the quality, availability and relevance of the data collected under the program and available to communities, and generally will improve environmental justice outcomes.

Finally, the EPA has promoted meaningful engagement from communities in developing the action, and in developing requirements that improve the quality of data submitted to the EPA, which are also available to communities as consistent with EPA's confidentiality determinations. The EPA has provided several opportunities for public engagement. The EPA opened the rule for public comment from August 1 to October 2, 2023, and hosted a virtual public hearing for the proposed revisions on August 21, 2023. The EPA provided a subsequent informational webinar on the technical aspects of the rule on September 7, 2023. The EPA has taken into consideration comments received from representatives and stakeholders in the development of this final rule.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. The Office of Information and Regulatory Affairs has determined that this action meets the criteria set forth by 5 U.S.C. 804(2).

L. Judicial Review

Under CAA section 307(b)(1), any petition for review of this final rule must be filed in the U.S. Court of Appeals for the District of Columbia Circuit by July 15, 2024. This final rule establishes requirements applicable to owners and operators of facilities in the petroleum and natural gas systems source category located across the United States that are subject to 40 CFR part 98 and therefore is ''nationally applicable'' within the meaning of CAA section 307(b)(1). Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. CAA section 307(d)(7)(B) also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with an electronic copy to the person listed in **FOR FURTHER INFORMATION CONTACT**, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20004. Note that under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

M. Determination Under CAA Section 307(d)

Pursuant to CAA section 307(d)(1)(V), the Administrator determined that this rule is subject to the provisions of CAA section 307(d). See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine'').

N. Severability

This final rule includes new and revised requirements for numerous provisions under various aspects of subpart W of the GHGRP. Therefore, this final rule is a multifaceted rule that addresses many separate things for independent reasons, as detailed in each respective portion of this preamble. We intend each portion of this rule to be severable from each other, though we took the approach of including all the parts in one rulemaking rather than promulgating multiple rules to ensure the changes are adopted and implemented in a coordinated manner, even though the changes are not inter-dependent.

For example, the EPA notes that our judgments regarding revisions for each industry segment consistent with our Clean Air Act authority and the directives in CAA section 136(h) reflect our determinations specific to considerations within each industry segment, while our judgment regarding the revisions to requirements for each type of source within each subpart W industry segment reflect our determinations specific to considerations for each source in each industry segment. The revisions for a given industry segment are intended to be and are implementable even absent revisions to the other industry segments (for example, Offshore Production revisions are independent from Onshore Petroleum and Natural Gas Production revisions), and likewise for each source within each industry segment, as they each independently ensure that the emissions reported under subpart W for the given source or industry segment at issue are consistent with the directives in CAA section 136(h) and improve the subpart W provisions as described in section II. of this preamble. Regarding revisions to requirements for each source being separate from each other, this includes, for a couple of examples, revisions to provisions for determining emissions emitted to the atmosphere being separate from revisions to provisions for determining emissions sent to a control device from a source as well as revisions to provisions for determining emissions emitted as an other large release event being separate from revisions to provisions for determining emissions from such a source when the emissions do not qualify as an other large release event. Accordingly, the EPA finds that revisions to each type of source in each industry segment are severable from revisions to each other type of source in each industry segment, and that at minimum revisions to each industry segment are severable from revisions to each of the other industry segments.

Additionally, our judgments regarding each calculation method for each source are likewise independent and do not rely on one another, as they each independently ensure that the emissions reported under subpart W for the given source or industry segment at issue are consistent with the directives in CAA section 136(h) and improve the subpart W provisions as described in section II. of this preamble. Accordingly, the EPA finds that each calculation method for each source is severable.

Finally, as described in section II. of this preamble, the EPA notes that there are changes the EPA is making related to amending certain requirements that apply to the general provisions, general stationary fuel combustion, and petroleum and natural gas systems source categories of the Greenhouse Gas Reporting Rule to improve calculation, monitoring, and reporting of greenhouse gas data for petroleum and natural gas systems facilities, as well as establishing and amending confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these amendments. The EPA's overall GHGRP subpart W program continues to be fully implementable even in the absence of any one or more of these elements.

Thus, the EPA has independently considered and adopted each of these portions of the final rule (including but not limited to the updates to each industry segment; each type of source in each industry segment; each calculation methodology for each source; requirements that apply to the general provisions, general stationary fuel combustion, and petroleum and natural gas systems source categories of the Greenhouse Gas Reporting Rule to improve calculation, monitoring, and reporting of greenhouse gas data for petroleum and natural gas systems facilities; and establishing and amending confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these amendments) and each is severable should there be judicial review. If a court were to invalidate any one of these elements of the final rule, we intend the remainder of this action to remain effective. Importantly, we have designed these different elements of the program to function sensibly and independently, the supporting basis for each of these elements of the final rule reflects that they are independently justified and appropriate, and we find each portion appropriate even if one or more other parts of the rule has been set aside. For example, if a reviewing court were to invalidate any of the revisions to address potential gaps in reporting of emissions data for specific sectors, the other regulatory amendments, including not only the other revisions to address potential gaps but also the other changes to discrete elements of the subpart W provisions, remain fully operable. Moreover, this list is not intended to be exhaustive, and should not be viewed as an intention by the EPA to consider other parts of the rule not explicitly listed here as not severable from other parts of the rule.

List of Subjects in 40 CFR Part 98

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

Michael S. Regan,

Administrator.

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

PART 98—MANDATORY GREENHOUSE GAS REPORTING

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

Authority: 42 U.S.C. 7401–7671q.

Subpart A—General Provision

■ 2. 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.

■ 3. Amend § 98.2 by revising paragraph (i)(3) and adding paragraph (i)(7) to read as follows:

§ 98.2 Who must report?

* * * * *

(i) * * *

(3) If the operations of a facility or supplier are changed such that all applicable processes and operations subject to paragraphs (a)(1) through (4) of this section cease to operate, then the owner or operator may discontinue complying with this part for the reporting years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all applicable processes and operations no later than March 31 of the year following such changes. If one or more processes or operations subject to paragraphs (a)(1) through (4) of this section at a facility or supplier cease to operate, but not all applicable processes or operations cease to operate, then the owner or operator is exempt from reporting for any such processes or operations in the reporting years following the reporting year in which cessation of the process or operation occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting for the process or operation no later than March 31 following the first reporting year in which the process or operation has ceased for an entire reporting year. Cessation of operations in the context of underground coal mines includes, but is not limited to, abandoning and sealing the facility. This paragraph (i)(3) does not apply to seasonal or other temporary cessation of operations. This paragraph (i)(3) does not apply to the municipal solid waste landfills source category (subpart HH of this part), or the industrial waste landfills source category (subpart TT of this part). This paragraph (i)(3) does not apply when there is a change in the owner or operator for facilities in industry segments with a unique definition of facility as defined in § 98.238 of the petroleum and natural gas systems source category (subpart W of this part), unless the changes result in permanent cessation of all applicable processes and operations. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation.

* * * * *

(7) If a facility in an industry segment with a unique definition of facility as defined in § 98.238 of the petroleum and natural gas systems source category (subpart W of this part) undergoes the type of change in owner or operator specified in paragraph § 98.4(n)(4) of this subpart, then the prior owner or operator may discontinue complying with the reporting requirements of this part for the facility for the reporting years following the year in which the change in owner or operator occurred, provided that the prior owner or operator submits a notification to the Administrator that announces the discontinuation of reporting no later than March 31 of the year following such change.

* * * * *

■ 4. Amend § 98.4 by revising the first sentence of 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. * * *

* * * * *

(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.

(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), then within 90 days after the change in the owner or operator, the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section. If the new owner or operator already had emission sources specified in § 98.232(c), (i), (j), or (m), as applicable, 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. 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 specified in § 98.232(c), (i), (j), or (m), as applicable, 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. The purchasing owner or operator shall continue to report under subpart W of this part for the new facility unless and until that facility meets one of the criteria in § 98.2(i).

(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 specified in § 98.232(c), (i), (j), or (m), as applicable, to their existing facility for purposes of reporting under subpart W of this part. 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 reporting facility are sold to multiple owners or operators within the same reporting year, such that the prior owner or operator of the facility does not retain any of the emission sources, then the prior owner or operator of the facility shall notify EPA within 90 days of the last transaction that all of the facility's emission sources were acquired by multiple purchasers, including the identity of the 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. Amend § 98.6 by revising the definitions ''Dehydrator,'' ''Dehydrator vent emissions,'' ''Desiccant,'' and ''Vapor recovery system'' to read as follows:

§ 98.6 Definitions.

* * * * *

Dehydrator means a device in which a liquid absorbent (including ethylene glycol, diethylene glycol, or triethylene glycol) or desiccant directly contacts a natural gas stream to remove water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) regenerator still vent 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.

* * * * *

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include, but are not limited to, molecular sieves, activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed and dissolves the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

* * * * *

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.

* * * * *

■ 6. Amend § 98.7 by redesignating paragraphs (d)(36) through (50) as (d)(37) though (51), respectively, adding new paragraph (d)(36), and adding paragraph (m)(15) to read as follows:

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

* * * * *

(d) * * *

(36) ASTM D6348–12 (Reapproved 2020) Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, Approved December 1, 2020, IBR approved for § 98.234(i).

* * * * *

(m) * * *

(15) Other Test Method 52 (OTM–52), Method for Determination of Combustion Efficiency from Enclosed Combustors Located at Oil and Gas Production Facilities, dated September 26, 2023, *https://www.epa.gov/emc/emc-other-test-methods*, IBR approved for § 98.233(n).

* * * * *

Subpart C—General Stationary Fuel Combustion Sources

■ 7. Amend § 98.33 by revising parameter ''EF'' of equation C–8 in paragraph (c)(1) introductory text, parameter ''EF'' of equation C–8a in paragraph (c)(1)(i), parameter ''EF'' of equation C–8b in paragraph (c)(1)(ii), parameter ''EF'' of equation C–9a in paragraph (c)(2), and parameter ''EF'' of equation C–10 in paragraph (c)(4) introductory text to read as follows:

§ 98.33 Calculating GHG emissions.

* * * * *

(c) * * *

(1) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from table C–2 to this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(i) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from table C–2 to this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(ii) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from table C–2 to this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(2) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from table C–2 to this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

(4) * * *

Where: * * *

EF = Fuel-specific default emission factor for CH_4 or N_2O, from table C–2 to this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas-fired reciprocating internal combustion engines and gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

■ 8. Amend § 98.36 by adding paragraphs (b)(12), (c)(1)(xii), and (c)(3)(xi) to read as follows:

§ 98.36 Data reporting requirements.

* * * * *

(b) * * *

(12) For natural gas-fired reciprocating internal combustion engines or gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4), you must also report:

(i) Type of equipment (*i.e.*, two-stroke lean-burn reciprocating internal combustion engine, four-stroke lean-burn reciprocating internal combustion engine, four-stroke rich-burn reciprocating internal combustion engine, or gas turbine).

(ii) Method by which the CH_4 emission factor was determined: performance test, manufacturer data, or default emission factor.

(iii) Value of the CH_4 emission factor.

(c) * * *

(1) * * *

(xii) For natural gas-fired reciprocating internal combustion engines or gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4), you must report the equipment type (*i.e.*, two-stroke lean-burn reciprocating internal combustion engine, four-stroke lean-burn reciprocating internal combustion engine, four-stroke rich-burn reciprocating internal combustion engine, and gas turbine), the method by which the CH_4 emission factor was determined (*i.e.*, performance test, manufacturer data, or default emission factor), and the average value of the CH_4 emission factor.

* * * * *

(3) * * *

(xi) For natural gas-fired reciprocating internal combustion engines or gas turbines at facilities subject to subpart W of this part, which must use a CH_4 emission factor determined in accordance with § 98.233(z)(4), you must report the equipment type (*i.e.*, two-stroke lean-burn reciprocating internal combustion engine, four-stroke lean-burn reciprocating internal combustion engine, four-stroke rich-burn reciprocating internal combustion engine, and gas turbine) the method by which the CH_4 emission factor was determined (*i.e.*, performance test, manufacturer data, or default emission factor), and the average value of the CH_4 emission factor.

* * * * *

■ 9. 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}
* * * * * * *		

[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 reciprocating internal combustion engines or gas turbines. For natural gas-fired reciprocating internal combustion engines or gas turbines, at facilities subject to subpart W of this part, reporters must use a CH_4 emission factor determined in accordance with § 98.233(z)(4).

* * * * *

Subpart W—Petroleum and Natural Gas Systems

■ 10. Amend § 98.230 by revising paragraphs (a)(2), (3), and (9) to read as follows:

§ 98.230 Definition of the source category.

(a) * * *

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels, all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Onshore petroleum and natural gas production also means all equipment on or associated with a single enhanced oil recovery (EOR) well-pad using CO2 or natural gas injection.

(3) *Onshore natural gas processing.* Onshore 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.

* * * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a downstream endpoint, typically a natural gas processing facility, a natural gas transmission pipeline or a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil here refers to hydrocarbon liquids of all API gravities).

* * * * *

■ 11. Amend § 98.232 by:
■ a. Revising paragraphs (a) and (b);
■ b. Adding paragraph (c)(2);
■ c. Revising paragraphs (c)(10), (17), and (21);
■ d. Adding paragraphs (c)(23) through (25);
■ e. Revising paragraphs (d)(5) and (7);
■ f. Adding paragraphs (d)(8) through (11);
■ g. Revising paragraphs (e)(3) and (8);
■ h. Adding paragraphs (e)(9) through (11);
■ i. Revising paragraphs (f)(6) and (8);
■ j. Adding paragraphs (f)(9) through (13);
■ k. Revising paragraphs (g)(6) and (7);
■ l. Adding paragraphs (g)(8) through (11);
■ m. Revising paragraphs (h)(7) and (8);
■ n. Adding paragraphs (h)(9) through (11) and (i)(8) through (11);
■ o. Revising paragraphs (j)(3), (6), and (10);
■ p. Adding paragraphs (j)(13) and (14); and
■ q. Revising paragraph (m).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (j) and (m) of this section, CO2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section. You must also report the information specified in paragraph (l) of this section, as applicable.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from the following sources. Offshore platforms do not need to report emissions from portable equipment.

(1) Equipment leaks (*i.e.*, fugitives), vented emission, and flare emission source types as identified by Bureau of Ocean Energy Management (BOEM) in compliance with 30 CFR 550.302 through 304.

(2) Other large release events.

(c) * * *

(2) Blowdown vent stacks.

* * * * *

(10) Hydrocarbon liquids and produced water storage tank emissions.

* * * * *

(17) Acid gas removal unit vents and nitrogen removal unit vents.

* * * * *

(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, dehydrators, heaters, and storage vessels.

* * * * *

(23) Other large release events.

(24) Drilling mud degassing.

(25) Crankcase vents.

(d) * * *

(5) Acid gas removal unit vents and nitrogen removal unit vents.

* * * * *

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters, and equipment leaks from all other components in gas service (not including thief hatches or other openings on storage vessels) that either are subject to equipment leak standards for onshore natural gas processing plants in § 60.5400b or § 60.5401b 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.

(10) Hydrocarbon liquids and produced water storage tank emissions.

(11) Crankcase vents.

(e) * * *

(3) Condensate storage tanks.

* * * * *

(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, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b 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.

(10) Dehydrator vents.

(11) Crankcase vents.

(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, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b 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 (f)(6) do not include thief hatches or other openings on a storage vessel.

* * * * *

(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, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b 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.

(10) Dehydrator vents.

(11) Blowdown vent stacks.

(12) Condensate storage tanks.

(13) Crankcase vents.

(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, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b 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, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b 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.

(9) Blowdown vent stacks.

(10) Acid gas removal unit vents and nitrogen removal unit vents.

(11) Crankcase vents.

(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, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b 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, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b 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 unit vents and nitrogen removal unit vents.

(10) Other large release events.

(11) Crankcase vents.

(i) * * *

(8) Other large release events.

(9) Blowdown vent stacks.

(10) Natural gas pneumatic device venting.

(11) Crankcase vents.

(j) * * *

(3) Acid gas removal unit vents and nitrogen removal unit vents.

* * * * *

(6) Hydrocarbon liquids and produced water storage tank emissions.

* * * * *

(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, dehydrators, heaters, and storage vessels.

* * * * *

(13) Other large release events.

(14) Crankcase vents.

* * * * *

(m) For onshore natural gas transmission pipeline, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Blowdown vent stacks.

(2) Other large release events.

(3) Equipment leaks listed in paragraph (m)(3)(i) or (ii) of this section, as applicable:

(i) Equipment leaks at transmission company interconnect metering-regulating stations.

(ii) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters at transmission company interconnect metering-regulating stations.

(4) Equipment leaks listed in paragraph (m)(4)(i) or (ii) of this section, as applicable:

(i) Equipment leaks at farm tap and/or direct sale metering-regulating stations.

(ii) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters at farm tap and/or direct sale metering-regulating stations.

(5) Transmission pipeline equipment leaks.

■ 12. Effective July 15, 2024, amend § 98.233 by:

■ a. Revising paragraphs (a), (c), the first sentence of paragraph (d)(2), and (d)(4) introductory text;

■ b. Adding paragraph (d)(12);

■ c. Revising paragraphs (e) introductory text, (e)(1) introductory text, and (e)(2);

■ d. Revising paragraph (g) introductory text and (g)(1)(i);

■ e. Revising parameter "$FR_{i,p}$" of equation W–12B in paragraph (g)(1)(iv);

■ f. Revising paragraph (i)(2)(i);

■ g. Revising paragraphs (j) introductory text, and (j)(2) introductory text and (j)(3);

■ h. Revising paragraphs (m)(1) through (3), (o)(10), (p)(10), (q) introductory text, (q)(1), and (q)(2) introductory text;

■ i. Adding paragraphs (q)(3) and (q)(4);

■ j. Revising paragraphs (s)(1) and (2) and (z)(1) introductory text;

■ k. Adding paragraph (z)(1)(iii); and

■ l. Revising paragraphs (z)(2) introductory text and (z)(2)(ii).

The revisions and additions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 emissions from natural gas pneumatic device venting using the applicable provisions as specified in this paragraph (a) of this section. If you have a continuous flow meter on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices or natural gas driven pneumatic pumps vented directly to the atmosphere for any portion of the year, you may use the method specified in paragraph (a)(1) of this section to calculate CH_4 and CO_2 emissions from those devices. For natural gas pneumatic devices for which you do not elect to use Calculation Method 1, use the applicable methods specified in paragraphs (a)(2) through (7) of this section to calculate CH_4 and CO_2 emissions. All references to natural gas pneumatic devices for Calculation Method 1 in this paragraph (a) also apply to combinations of natural gas pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line. For Reporting Year 2024, you may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs (a)(1) through (4) of this section.

(1) *Calculation Method 1.* If you have or elect to install a continuous flow meter that is capable of meeting the requirements of § 98.234(b) on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices and natural gas driven pneumatic pumps that are vented directly to the atmosphere, you may use the applicable methods specified in paragraphs (a)(1)(i) through (iv) of this section to calculate CH_4 and CO_2 emissions from those devices.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are routed to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual volumetric flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, calculate the total volumetric flow for the year based on the measured volumetric flow times the total hours in the calendar year the devices were in service (*i.e.*, supplied with natural gas) divided by the number of hours the devices were in service (*i.e.*, supplied with natural gas) and the volumetric flow was being measured.

(B) Convert the natural gas volumetric flow from paragraph (a)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (a)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are vented directly to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual mass flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, calculate the total mass flow for the year based on the measured mass flow times the total hours in the calendar year the devices were in service (*i.e.*, supplied with natural gas) divided by the number of hours the devices were in service (*i.e.*, supplied with natural gas) and the mass flow was being measured.

(B) Convert the cumulative mass flow from paragraph (a)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(iii) If the flow meter on the natural gas supply line serves both natural gas pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data.

(iv) The flow meter must be operated and calibrated according to the methods set forth in § 98.234(b).

(2) *Calculation Method 2.* Except as provided in paragraph (a)(1) of this section, you may elect to measure the volumetric flow rate of each natural gas pneumatic device vent that vents directly to the atmosphere at your well-pad site, gathering and boosting site, or facility, as applicable, as specified in paragraphs (a)(2)(i) through (ix) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be measured or for which emissions are calculated according to the requirements in this paragraph (a)(2).

(i) For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you may elect to measure your pneumatic devices according to this Calculation Method 2 for some well-pad sites or gathering and boosting sites and use other methods for other sites. When you elect to measure the emissions from natural gas pneumatic devices according to this Calculation Method 2 at a well-pad site or gathering and boosting site, you must measure all natural gas pneumatic devices that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year and you must measure and calculate emissions according to the provisions in paragraphs (a)(2)(iii) through (viii) of this section.

(ii) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments electing to use this Calculation Method 2, you must measure all natural gas pneumatic devices vented directly to the atmosphere at your facility each year or, if your facility has 26 or more pneumatic devices, over multiple years, not to exceed the number of years as specified in paragraphs (a)(2)(ii)(A) through (D) of this section. If you elect to measure your pneumatic devices over multiple years, you must measure approximately the same number of devices each year. You must measure and calculate emissions for natural gas pneumatic devices at your facility according to the provisions in paragraphs (a)(2)(iii) through (ix), as applicable.

(A) If your facility has at least 26 but not more than 50 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 2 years.

(B) If your facility has at least 51 but not more than 75 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 3 years.

(C) If your facility has at least 76 but not more than 100 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 4 years.

(D) If your facility has 101 or more natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 5 years.

(iii) For all industry segments, determine the volumetric flow rate of each natural gas pneumatic device vent (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (a)(2)(iii)(A) through (E) of this section. You must measure the emissions under conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the device or manually actuating the device.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth in § 98.234(d), you must measure the emissions from each device for a minimum of 15 minutes while the device is in service (*i.e.*, supplied with natural gas), except for natural gas pneumatic isolation valve actuators. For natural gas pneumatic isolation valve actuators, you must measure the emissions from each device for a minimum of 5 minutes while the device is in service (*i.e.,* supplied with natural gas). If there is no measurable flow from the natural gas pneumatic device after the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c) except you need only fill one bag to have a valid measurement. You must collect sample for a minimum of 5 minutes for natural gas pneumatic isolation valve actuators or 15 minutes for other natural gas pneumatic devices. If no gas is collected in the calibrated bag during the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section. If gas is collected in the bag during the minimum sampling period, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (a)(2)(iii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas pneumatic device vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section.

(E) If there is measurable flow from the device vent, calculate the volumetric flow rate of each natural gas pneumatic device vent (in standard cubic feet per hour) by dividing the cumulative volume of natural gas measured during the measurement period (in standard cubic feet) by the duration of the measurement (in hours).

(iv) For all industry segments, if there is measurable flow from the device vent, calculate the volume of natural gas emitted from each natural gas pneumatic device vent as the product of the natural gas flow rate measured in paragraph (a)(2)(iii) of this section and the number of hours the pneumatic device was in service (*i.e.,* supplied with natural gas) in the calendar year.

(v) For all industry segments, if there is no measurable flow from the device vent, estimate the emissions from the device according to the methods in paragraphs (a)(2)(v)(A) through (C) of this section, as applicable.

(A) For continuous high bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(*2*) Confirm that the device is correctly characterized as a continuous high bleed pneumatic device according to the provisions in paragraph (a)(7) of this section. If the device type was mischaracterized, recharacterize the device type and use the appropriate methods in paragraph (a)(2)(v)(B) or (C) of this section, as applicable.

(*3*) Upon confirmation of the items in paragraphs (a)(2)(v)(A)(*1*) and (*2*) of this section, remeasure the device vent using a different measurement method specified in § 98.234(b) through (d) or longer monitoring duration until there is a measurable flow from the device and calculate the natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(B) For continuous low bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(*2*) Determine natural gas bleed rate (in standard cubic feet per hour) at the supply pressure used for the pneumatic device based on the manufacturer's steady state natural gas bleed rate reported for the device. If the steady state bleed rate is reported in terms of air consumption, multiply the air consumption rate by 1.29 to calculate the steady state natural gas bleed rate. If a steady state bleed rate is not reported, follow the requirements in paragraph (a)(2)(v)(B)(*4*) of this section.

(*3*) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the natural gas steady state bleed rate determined in paragraph (a)(2)(v)(B)(2) of this section and number of hours the pneumatic device was in service (*i.e.,* supplied with natural gas) in the calendar year.

(*4*) If a steady state bleed rate is not reported, reassess whether the device is correctly characterized as a continuous low bleed pneumatic device according to the provisions in paragraph (a)(7) of this section. If the device is confirmed to be a continuous low bleed pneumatic device, you must remeasure the device vent using a different measurement method specified in § 98.234(b) through (d) or longer monitoring duration until there is a measurable flow from the device and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section. If the device type was mischaracterized, recharacterize the device type and use the appropriate methods in paragraph (a)(2)(v)(A) or (C) of this section, as applicable.

(C) For intermittent bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions according to paragraph (a)(2)(iv) of this section. For devices confirmed to be in-service during the measurement period, calculate natural gas emissions according to paragraphs (a)(2)(v)(C)(*2*) through (*5*) of this section.

(*2*) Calculate the volume of the controller, tubing and actuator (in actual cubic feet) based on the device and tubing size.

(*3*) Sum the volumes in paragraph (a)(2)(v)(C)(*2*) of this section and convert the volume to standard cubic feet following the methods specified in paragraph (t)(1) of this section based on the natural gas supply pressure.

(*4*) Estimate the number of actuations during the year based on company records, if available, or best engineering estimates. For isolation valve actuators, you may multiply the number of valve closures during the year by 2 (one actuation to close the valve; one actuation to open the valve).

(*5*) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the per actuation volume in standard cubic feet determined in paragraph (a)(2)(v)(C)(*3*) of this section, the number of actuations during the year as determined in paragraph (a)(2)(v)(C)(*4*) of this section, and the relay correction factor. Use 1 for the relay correction factor if there is no relay; use 3 for the relay correction factor if there is a relay.

(vi) For each pneumatic device, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (a)(2)(iv) or (v) of this section, as applicable, to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(vii) For each pneumatic device, convert the GHG volumetric emissions at standard conditions determined in paragraph (a)(2)(vi) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(viii) Sum the CO_2 and CH_4 mass emissions determined in paragraph (a)(2)(vii) of this section separately for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(ix) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments, if you chose to conduct natural gas pneumatic device measurements over multiple years, ''n,'' according to paragraph (a)(2)(ii) of this section, then you must calculate the emissions from all pneumatic devices at your facility as specified in paragraph (a)(2)(ix)(A) through (E) of this section.

(A) Use the emissions calculated in (a)(2)(viii) of this section for the devices measured during the reporting year.

(B) Calculate the whole gas emission factor for each type of pneumatic device at the facility using equation W–1A to this section and all available data from the current year and the previous years in your monitoring cycle (n-1 years) for which natural gas pneumatic device vent measurements were made according to Calculation Method 2 in paragraph (a)(2) of this section (*e.g.,* if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_t = \frac{\sum_{y=1}^{n} MT_{s,t,y}}{\sum_{y=1}^{n} Count_{t,y}} \quad \text{(Eq. W-1A)}$$

Where:

EF_t = Whole gas population emission factor for natural gas pneumatic device vents of type ''t'' (continuous high bleed, continuous low bleed, intermittent bleed), in standard cubic feet per hour per device.

$MT_{s,t,y}$ = Volumetric whole gas emissions rate measurement at standard (''s'') conditions from component type ''t'' during year ''y'' in standard cubic feet per hour, as calculated in paragraph (a)(2)(iii) [if there was measurable flow from the device vent], (a)(2)(v)(B)(*2*), or (a)(2)(v)(C)(*6*) of this section, as applicable.

$Count_{t,y}$ = Count of natural gas pneumatic device vents of type ''t'' measured according to Calculation Method 2 in year ''y.''

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic device vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices that were not measured during the reporting year using equation W–1B to this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1B)}$$

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 paragraphs (a)(5) through (7) of this section that vent directly to the atmosphere and that were not directly measured according to the requirements in paragraph (a)(1) or (a)(2)(iii) 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’’ (continuous high bleed, continuous low bleed, intermittent bleed) as calculated using equation W–1A to this section.

GHG_i = Concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraph (u)(2) 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.

(D) Convert the volumetric emissions calculated using equation W–1B to this section to CH_4 and CO_2 mass emissions using the methods specified in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (a)(2)(ix)(A) and (D) of this section separately for each type of pneumatic device (continuous high bleed, continuous low bleed, intermittent bleed) to calculate the total CH_4 and CO_2 mass emissions by device type for Calculation Method 2.

(3) *Calculation Method 3.* For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you may elect to use the applicable methods specified in paragraphs (a)(3)(i) through (iv) of this section, as applicable, to calculate CH_4 and CO_2 emissions from your natural gas pneumatic devices that are vented directly to the atmosphere at your site except those that are measured according to paragraph (a)(1) or (2) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be monitored or for which emissions are calculated according to the requirements in this paragraph (a)(3). You may not use this Calculation Method 3 for those well-pad sites or gathering and boosting sites for which you elected to measure emissions according to paragraph (a)(2) of this section.

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere, you must calculate CH_4 and CO_2 volumetric emissions using either the methods in paragraph (a)(3)(i)(A) or (B) of this section.

(A) Measure all continuous high bleed and continuous low bleed pneumatic devices at your well-pad site or gathering and boosting site, as applicable, according to the provisions in paragraphs (a)(2) of this section.

(B) Use equation W–1B to this section, except use the appropriate default whole gas population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ‘‘t’’ (continuous high bleed and continuous low bleed) as listed in table W–1A to this subpart.

(ii) For intermittent bleed pneumatic devices, monitor each intermittent bleed pneumatic device at your well-pad site or gathering and boosting site as specified in paragraphs (a)(3)(ii)(A) through (C) of this section, as applicable.

(A) You must use one of the monitoring methods specified in § 98.234(a)(1) through (3) except that the monitoring dwell time for each device vent must be at least 2 minutes or until a malfunction is identified, whichever is shorter. A device is considered malfunctioning if any leak is observed when the device is not actuating or if a leak is observed for more than 5 seconds, or the extended duration as specified in paragraph (a)(3)(ii)(C) of this section if applicable, during a device actuation. If you cannot tell when a device is actuating, any observed leak from the device indicates a malfunctioning device.

(B) If you elect to monitor emissions from natural gas pneumatic devices at a well-pad site or gathering and boosting site according to this Calculation Method 3, you must monitor all natural gas intermittent bleed pneumatic devices that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year. You must monitor the natural gas intermittent bleed pneumatic devices under conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the device or manually actuating the device.

(C) For certain throttling pneumatic devices or isolation valve actuators on pipes greater than 5 inches in diameter, that may actuate for more than 5 seconds under normal conditions, you may elect to identify individual devices for which longer bleed periods may be allowed as specified in paragraphs (a)(3)(ii)(C)(*1*) and (*2*) of this section prior to monitoring these devices for the first time.

(*1*) You must identify the devices for which extended actuations are considered normal operations. For each device identified, you must determine the typical actuation time and maintain documentation and rationale for the extended actuation duration value.

(*2*) You must clearly and permanently tag the device vent for each natural gas pneumatic device that has an extended actuation duration. The tag must include the device ID and the normal duration period (in seconds) as determined and documented for the device as specified in paragraph (a)(3)(ii)(C)(*1*) of this section.

(iii) For intermittent bleed pneumatic devices that are monitored according to paragraph (a)(3)(ii) of this section during the reporting year, you must calculate CH_4 and CO_2 volumetric emissions from intermittent bleed natural gas pneumatic devices vented directly to the atmosphere using equation W–1C to this section.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\left\{K_1 \times T_{mal,z} + K_2 \times \left(T_{t,z} - T_{mal,z}\right)\right\} + \left(K_2 \times Count \times T_{avg}\right)\right] \qquad \text{(Eq. W-1C)}$$

Where:

E_i = Annual total volumetric emissions of GHG_i from intermittent bleed natural gas 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 natural gas pneumatic device as defined in paragraph (u)(2) of this section.

x = Total number of intermittent bleed natural gas pneumatic 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.

K_1 = Whole gas emission factor for malfunctioning intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device. Use 24.1 for well-pad sites in the onshore petroleum and natural gas production industry segment and use 16.1 for gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segment.

$T_{mal,z}$ = The total time the surveyed pneumatic device ''z'' was in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning, 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.

$T_{t,z}$ = The total time the surveyed natural gas pneumatic device ''z'' was in service (*i.e.,* supplied with natural gas) during the year. Default is 8,760 hours for non-leap years and 8,784 hours for leap years.

K_2 = Whole gas emission factor for properly operating intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device. Use 0.3 for well-pad sites in the onshore petroleum and natural gas production industry segment and use 2.8 for gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segment.

Count = Total number of intermittent bleed natural gas pneumatic devices that were never observed to be malfunctioning during any monitoring survey during the year.

T_{avg} = The average time the intermittent bleed natural gas 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 for non-leap years and 8,784 hours for leap years.

(A) 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–1C to this section.

(B) For the purposes of paragraph (a)(3)(iii)(A) of this section, a complete monitoring survey is a survey of all intermittent bleed natural gas pneumatic devices vented directly to the atmosphere at a well-pad site for onshore petroleum and natural gas production facilities (except those measured according to paragraph (a)(1) of this section) or all intermittent bleed pneumatic devices vented directly to the atmosphere at a gathering and boosting site for onshore petroleum and natural gas gathering and boosting facilities (except those measured according to paragraph (a)(1) of this section).

(iv) You must convert the CH_4 and CO_2 volumetric emissions as determined according to paragraphs (a)(3)(i) and (iii) of this section and calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(4) *Calculation Method 4.* You may elect to calculate CH_4 and CO_2 emissions from your natural gas pneumatic devices at your facility using the methods specified in paragraphs (a)(4)(i) and (ii) of this section except those that are measured according to paragraphs (a)(1) through (3) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be monitored or for which emissions are calculated according to the requirements in this paragraph (a)(4). You may not use this Calculation Method 4 for those devices for which you elected to measure emissions according to paragraph (a)(1), (2), or (3) of this section.

(i) You must calculate CH_4 and CO_2 volumetric emissions using equation W–1B to this section, except use the appropriate default whole gas population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' (continuous high bleed, continuous low bleed, and intermittent bleed) listed in table W–1A to this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities, table W–3B to this subpart for onshore natural gas transmission compression facilities, and table W–4B to this subpart for underground natural gas storage facilities.

(ii) You must convert the CH_4 and CO_2 volumetric emissions as determined according to paragraphs (a)(4)(i) of this section and calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(5) *Counts of natural gas pneumatic devices.* For all industry segments, determine ''Countt'' for equation W–1A, W–1B, or W–1C to this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the total number of devices at the well-pad site, gathering and boosting site, or facility, as applicable, the number of devices that are vented directly to the atmosphere and the number of those devices that were measured or monitored during the reporting year, as applicable, except as specified in paragraph (a)(6) of this section.

(6) *Counts of onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting natural gas pneumatic devices.* For facilities in the onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine the total number of natural gas pneumatic devices at the facility and the number of devices that are vented directly to the atmosphere for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed), as applicable, using engineering estimates based on best available data. Counts of natural gas pneumatic devices measured or monitored during the reporting year must be made based on actual counts.

(7) *Type of natural gas pneumatic devices.* For all industry segments, determine the type of natural gas pneumatic device using engineering estimates based on best available information.

* * * * *

(c) *Natural gas driven pneumatic pump venting.* Calculate CH_4 and CO_2

emissions from natural gas driven pneumatic pumps as specified in paragraph (c)(1), (2), or (3) of this section, as applicable. If you have a continuous flow meter on the natural gas supply line that is dedicated to any one or more natural gas driven pneumatic pumps, each of which only vents directly to the atmosphere, you may use Calculation Method 1 as specified in paragraph (c)(1) of this section to calculate vented CH_4 and CO_2 emissions from those pumps. You may use Calculation Method 1 for any portion of a year when all of the pumps on the continuously measured natural gas supply line were vented directly to atmosphere. For natural gas driven pneumatic pumps for which you do not elect to use Calculation Method 1, use either the method specified in paragraph (c)(2) or (3) of this section to calculate CH_4 and CO_2 emissions; you may not use Calculation Method 2 for some vented natural gas driven pneumatic pumps and Calculation Method 3 for other natural gas driven pneumatic pumps. All references to natural gas driven pneumatic pumps for Calculation Method 1 in this paragraph (c) also apply to combinations of natural gas pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line. You do not have to calculate emissions from natural gas driven pneumatic pumps covered in paragraph (e) of this section under this paragraph (c). For Reporting Year 2024, you may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs (c)(1) through (3) of this section.

(1) *Calculation Method 1.* If you have or elect to install a continuous flow meter that is capable of meeting the requirements of § 98.234(b) on a supply line to natural gas driven pneumatic pumps, then for the period of the year when the natural gas supply line is dedicated to any one or more natural gas driven pneumatic pumps, and each of the pumps is vented directly to the atmosphere, you may use the applicable methods specified in paragraphs (c)(1)(i) or (ii) of this section to calculate vented CH_4 and CO_2 emissions from those pumps.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total volumetric flow for the year based on the measured volumetric flow times the total hours in the calendar year in which at least one of the pumps connected to the supply line was pumping liquid divided by the number of hours in the year when at least one of pumps connected to the supply line was pumping liquid and the volumetric flow was being measured.

(B) Convert the natural gas volumetric flow from paragraph (c)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (c)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total mass flow of vented natural gas emissions for the year based on the measured mass flow times the total hours in the calendar year in which at least one of the pumps connected to the supply line was pumping liquid divided by the number of hours in the year when at least one of pumps connected to the supply line was pumping liquid and the mass flow was being measured.

(B) Convert the cumulative mass flow from paragraph (c)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(iii) If the supply line serves both natural gas pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to natural gas pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data.

(iv) The flow meter must be operated and calibrated according to the methods set forth in § 98.234(b).

(2) *Calculation Method 2.* Except as provided in paragraph (c)(1) of this section, you may elect to measure the volumetric flow rate of each natural gas driven pneumatic pump at your facility that vents directly to the atmosphere as specified in paragraphs (c)(2)(i) through (vii) of this section. You must exclude the counts of pumps measured according to paragraph (c)(1) of this section from the counts of pumps to be measured and for which emissions are calculated according to the requirements in this paragraph (c)(2).

(i) Measure all natural gas driven pneumatic pumps at your facility at least once every 5 years. If you elect to measure your pneumatic pumps over multiple years, you must measure approximately the same number of pumps each year. When you measure the emissions from natural gas driven pneumatic pumps at a well-pad site or gathering and boosting site, you must measure all pneumatic pumps that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year.

(ii) Determine the volumetric flow rate of each natural gas driven pneumatic pump (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (c)(2)(ii)(A) through (D) of this section. You must measure the emissions under conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the pump.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth in § 98.234(d), you must measure the emissions from each pump for a minimum of 5 minutes, during a period when the pump is continuously pumping liquid.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c), except under § 98.234(c)(2), only one bag must be filled to have a valid measurement. You must collect sample for a minimum of 5 minutes, or until the bag is full, whichever is shorter, during a period when the pump is continuously pumping liquid. If the bag is not full after 5 minutes, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (c)(2)(ii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas driven pneumatic pump vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section. Convert the measured flow during the test period to standard cubic feet per hour, as appropriate.

(iii) Calculate the volume of natural gas emitted from each natural gas driven pneumatic pump vent as the product of the natural gas emissions flow rate measured in paragraph (c)(2)(ii) of this section and the number of hours that liquid was pumped by the pneumatic pump in the calendar year.

(iv) For each pneumatic pump, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (c)(2)(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 pneumatic pump, convert the GHG volumetric emissions at standard conditions determined in paragraph (c)(2)(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 (c)(2)(v) of this section.

(vii) If you chose to conduct natural gas pneumatic pump measurements over multiple years, ''n,'' according to paragraph (c)(2)(i) of this section, then you must calculate the emissions from all pneumatic pumps at your facility as specified in paragraph (c)(2)(vii)(A) through (D) of this section.

(A) Use the emissions calculated in paragraph (c)(2)(vi) of this section for the pumps measured during the reporting year.

(B) Calculate the whole gas emission factor for pneumatic pumps at the facility using equation W–2A to this section and all available data from the current year and the previous years in your monitoring cycle (n-1 years) for which natural gas pneumatic pump vent measurements were made according to Calculation Method 2 in paragraph (c)(2) of this section (*e.g.,* if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_s = \frac{\sum_{y=1}^{n} MT_{s,y}}{\sum_{y=1}^{n} Count_y} \quad \text{(Eq. W-2A)}$$

Where:

EF_s = Whole gas population emission factor for natural gas pneumatic pump vents, in standard cubic feet per hour per pump.

$MT_{s,y}$ = Volumetric whole gas emissions rate measurement at standard (''s'') conditions during year ''y'' in standard cubic feet per hour, as calculated in paragraph (c)(2)(iii) of this section.

$Count_y$ = Count of natural gas driven pneumatic pump vents measured according to Calculation Method 2 in year ''y.''

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic pump vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps that were not measured during the reporting year using equation W–2B to this section.

$$E_{s,i} = Count \times EF_s \times GHG_i \times T \quad \text{(Eq. W-2B)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas driven pneumatic pump vents, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps that vented directly to the atmosphere and that were not directly measured according to the requirements in paragraphs (c)(1) or (c)(2)(ii) of this section.

EF_s = Population emission factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) as calculated using equation W–2A to this section.

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 pumping liquid using engineering estimates based on best available data. Default is 8,760 hours for pumps that only vented directly to the atmosphere.

(D) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions calculated using equation W–2B to this section using calculations in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (c)(2)(vii)(A) and (D) of this section to calculate the total CH_4 and CO_2 mass emissions for Calculation Method 2.

(3) *Calculation Method 3.* If you elect not to measure emissions as specified in Calculation Method 2, then you must use the applicable method specified in paragraphs (c)(3)(i) and (ii) of this section to calculate CH_4 and CO_2 emissions from all natural gas driven pneumatic pumps that are vented directly to the atmosphere at your facility and that are not measured according to paragraph (c)(1) of this section. You must exclude the counts of devices measured according to paragraph (c)(1) of this section from the counts of pumps for which emissions are calculated according to the requirements in this paragraph (c)(3).

(i) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps using equation W–2B to this section, except use the appropriate default whole gas population emission factor for natural gas pneumatic pump vents (in standard cubic feet per hour per device) as provided in table W–1A to this subpart.

(ii) Convert the CH_4 and CO_2 volumetric emissions determined according to paragraph (c)(3)(i) of this section to CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(d) * * *

(2) *Calculation Method 2.* Except as specified in paragraph (d)(4) of this section, if a CEMS is not available but a vent meter is installed, use the CO_2 composition and annual volume of vent gas to calculate emissions using equation W–3 to this section.

* * * * *

(4) *Calculation Method 4.* If CEMS or a vent meter is not installed, you may calculate emissions using any standard simulation software package, such as AspenTech HYSYS®, or API 4679 AMINECalc, that uses the Peng-Robinson equation of state and speciates CO_2 emissions. You may also use this method if a vent meter is installed but a CEMS is not, in which case you must determine the difference between the annual volume of vent gas measured by the vent meter and the simulated annual volume of vent gas according to paragraph (d)(12) of this section. A minimum of the following, determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best

available data, must be used to characterize emissions:

* * * * *

(12) *Comparison of annual volume of vent gas.* If a vent meter is installed but you wish to use Calculation Method 4 rather than Calculation Method 2 for an AGR, use equation W–4D to this section to determine the difference between the annual volume of vent gas measured by the vent meter and the simulated annual volume of vent gas.

$$PD = \frac{\left|V_{a,meter} - V_{a,sim}\right|}{\left(\frac{V_{a,meter}+V_{a,sim}}{2}\right)} \times 100\% \qquad \text{(Eq. W-4D)}$$

Where:

PD = Percent difference between vent gas volumes, %.

$V_{a,meter}$ = Total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

$V_{a,sim}$ = Total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by a standard simulation software package consistent with paragraph (d)(4) of this section.

(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 (e)(4) of this section. For glycol dehydrators that have an annual average daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day, use Calculation Method 1 in paragraph (e)(1) of this section. For glycol dehydrators that have an annual average of 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, use either Calculation Method 1 in paragraph (e)(1) of this section or Calculation Method 2 in paragraph (e)(2) 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)(5) of this section. If emissions from dehydrator vents are routed to a flare or regenerator fire-box/fire tubes, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(6) of this section. For Reporting Year 2024, you may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs (e)(1) through (3) of this section.

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators 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. 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:

* * * * *

(2) *Calculation Method 2.* Calculate annual volumetric emissions from glycol dehydrators using equation W–5 to this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators that have an annual average daily natural gas throughput that is less than 0.4 million standard cubic feet per day for which you elect to use this Calculation Method 2.

1000 = Conversion of EF_i in thousand standard cubic feet to standard cubic feet.

* * * * *

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using equation W–10A or equation W–10B to this section. Equation W–10A to this section applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers and equation W–10B to this section applies when the gas flowback vent or flare volume is measured for each completion or workover. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use equation W–10A to this section, you must follow the procedures specified in paragraph (g)(1) of this section. If you elect to use equation W–10B to this section, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. To calculate emissions during the initial period, you must calculate the gas flowback rate in the initial flowback period as described in equation W–10B to this section. Alternatively, you may use a multiphase flow meter placed on the flow line downstream of the wellhead and ahead of the separator to directly measure gas flowback during the initial period when flowback is routed to open pits or tanks. If you use a multiphase flow meter, measurements must be taken from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation. For Reporting Year 2024, you may use data collected by a multiphase flow meter anytime during the calendar year. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_{p,s} \times FRM_s \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \div 2 \times Z_{p,i} \times PR_{s,p} \right] \right] \qquad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \div 2 \times Z_{p,i} \right] \right] \qquad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each sub-basin and well type combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of each well p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback for each well, p, as determined by using an appropriate meter according to methods described in § 98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of vented or flared gas for each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

$FR_{p,i}$ = Flow rate vented or flared of each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in § 98.234(b). Alternatively, flow rate during the initial period may be measured using a multiphase flow meter installed upstream of the separator capable of accurately measuring gas flow prior to separation.

$Z_{p,i}$ = If a multiphase flow meter is used to measure flowback during the initial period, then $Z_{p,i}$ is equal to 1. If flowback is measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, then $Z_{p,i}$ is equal to 0.5.

(1) * * *

(i) *Calculation Method 1.* You must use equation W–12A to this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use equation W–12B to this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in equations W–12A and W–12B to this section, you must use a recording flow meter (digital or analog) installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in § 98.234(b). Alternatively, you may use a multiphase flow meter placed on the flow line downstream of the wellhead and ahead of the separator to directly measure gas flowback during the initial period when flowback is routed to open pits or tanks. If you use a multiphase flow meter, measurements must be taken from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation. For Reporting Year 2024, you may use data collected by a multiphase flow meter anytime during the calendar year.

* * * * *

(iv) * * *

$FR_{i,p}$ = Initial measured gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or initial calculated flow rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section in standard cubic feet per hour for well(s), p, for each sub-basin and well type combination. Measured and calculated $FR_{i,p}$ values must be based on flow conditions at the beginning of the separation period and must be expressed at standard conditions or measured using a multiphase flow meter installed upstream of the separator capable of accurately measuring gas flow prior to separation.

* * * * *

(i) * * *

(2) * * *

(i) Calculate the total annual natural gas emissions from each unique physical volume that is blown down using either equation W–14A or W–14B to this section. For Reporting Year 2024, you may use best available information to determine temperature and pressure of any emergency blowdown during the calendar year from the industry segments specified.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s Z_a} \right) - V * C \right) \quad \text{(Eq. W-14A)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Unique physical volume between isolation valves, in cubic feet, as calculated in paragraph (i)(1) of this section.

C = Purge factor is 1 if the unique physical volume is not purged, or 0 if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60 °F).

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_s = Absolute pressure at standard conditions (14.7 psia).

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.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

$$E_{s,n} = \sum_{p=1}^{N} \left[V_p \left(\frac{(459.67 + T_s)(P_{a,b,p} - P_{a,e,p})}{(459.67 + T_{a,p}) P_s Z_a} \right) \right] \quad \text{(Eq. W-14B)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

p = Individual occurrence of blowdown for the same unique physical volume.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V_p = Unique physical volume between isolation valves, in cubic feet, for each blowdown ‘‘p.’’

T_s = Temperature at standard conditions (60 °F).

$T_{a,p}$ = 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_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = 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.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(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 wells, 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 oil 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, gas-liquid separators, or non-separator equipment with annual average daily throughput less than 10 barrels per day, use Calculation Method 1, 2, or 3 as specified in paragraphs (j)(1) through (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. For Reporting Year 2024, you may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs (j)(1) through (3) of this section.

* * * * *

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators. Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(ii) of this section for wells 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 CO_2 emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

* * * * *

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions using Equation W–15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \quad \text{(Eq. W-15)}$$

Where:

$E_{s,I}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

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 oil directly to the storage tank for which you elect to use this Calculation Method 3.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

* * * * *

(m) * * *

(1) If you measure the gas flow to a vent using a continuous flow measurement device, you may use measurements collected from a continuous flow measurement device anytime during the calendar year.

(2) If you do not measure the gas flow to a vent using a continuous flow measurement device or you do measure the gas flow but do not elect to use the measurements, you must follow the procedures in paragraphs (m)(2)(i) through (iii) of this section.

(i) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

(ii) If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (m)(2)(ii)(A) or (B) of this section to determine GOR.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in § 98.234(b).

(iii) Estimate venting emissions using equation W–18 to this section.

$$E_{s,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} \left[\left(GOR_{p,q} * V_{p,q} \right) - SG_{p,q} \right] \quad \text{(Eq. W-18)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting at standard conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in sub-basin q, in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year 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 during time periods in which associated gas was vented or flared.

x = Total number of wells in sub-basin that vent or flare associated gas.

y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

(3) [Reserved]

* * * * *

(o) * * *

(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 volumetric emissions from centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (o)(10)(i) through (iv) of this section, as applicable. For Reporting Year 2024, you may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs (o)(10)(i) through (iv) of this section.

(i) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility with dry seals and self-contained wet seals, you may measure compressor emissions by conducting the volumetric emission measurements as required by § 60.5380b(a)(5) of this chapter, conducting all additional volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculating emissions as specified in paragraphs (o)(6) through (9) of this section. Conduct all measurements required by this paragraph (o)(10)(i) at the frequency specified by § 60.5380b(a)(4) of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5380b(a)(4) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (o)(6)(ii) of this section.

(ii) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility, you may elect to conduct the volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (o)(6) through (9) of this section.

(iii) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (o)(10)(i) of this section does not apply and you do not elect to conduct the volumetric measurements specified in paragraph (o)(1) of this section, you must calculate total atmospheric wet seal oil degassing vent emissions from all centrifugal compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using equation W–25A to this section.

$$E_{s,i} = \sum_{p=1}^{Count} E_{s,i,p} \qquad \text{(Eq. W-25A)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from all centrifugal compressors, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors with wet seal oil degassing vents that are vented directly to the atmosphere.

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for centrifugal compressor p, at standard conditions, in cubic feet, calculated using equation W–25B to this section.

(iv) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (o)(10)(i) of this section does not apply, and you do not elect to conduct the volumetric measurements specified in paragraph (o)(1) of this section, you must calculate wet seal oil degassing vent emissions from each centrifugal compressor using equation W–25B to this section.

$$E_{s,i,p} = EF_{s,p} \times \frac{T_p}{T_{total}} \times \frac{GHG_{i,p}}{GHG_{EF}} \qquad \text{(Eq. W-25B)}$$

Where:

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for centrifugal compressor p, at standard conditions, in cubic feet.

$EF_{s,p}$ = Emission factor for centrifugal compressor p, in standard cubic feet per year. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

T_p = Total time centrifugal compressor p was in operating mode, for which $E_{s,i,p}$ is being calculated in the reporting year, in hours.

T_{total} = Total hours per year. Use 8784 in leap years and use 8760 in all other years.

$GHG_{i,p}$ = Mole fraction of GHG (either CH_4 or CO_2) in the vent gas for centrifugal compressor p in operating mode; use the appropriate gas compositions in paragraph (u)(2) of this section.

GHG_{EF} = Mole fraction of GHG (either CH_4 or CO_2) used in the determination of $EF_{s,p}$. Use 0.95 for CH_4 and 0.05 for CO_2.

* * * * *

(p) * * *

(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 volumetric emissions from reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (p)(10)(i) through (iv) of this section, as applicable. For Reporting Year 2024, you may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs (p)(10)(i) through (iv) of this section.

(i) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility, you may measure compressor emissions by conducting the volumetric emission measurements as required by § 60.5385b(b) and (c) of this chapter, conducting any additional volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculating emissions as specified in paragraphs (p)(6) through (9) of this section. Conduct all measurements required by this paragraph (p)(10)(i) at the frequency specified by § 60.5385b(a) of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5385b(a) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (p)(6)(ii) of this section.

(ii) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility, you may elect to conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (p)(6) through (9) of this section.

(iii) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (p)(10)(i) of this section does not apply, and you do not elect to conduct volumetric emission measurements specified in paragraph (p)(1) of this section, you must calculate total atmospheric rod packing emissions from all reciprocating compressors venting at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using equation W–29D to this section.

$$E_{s,i} = \sum_{p=1}^{Count} E_{s,i,p} \quad \text{(Eq. W-29D)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from all reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors with rod packing emissions vented directly to the atmosphere.

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for reciprocating compressor p, at standard conditions, in cubic feet, calculated using equation W–29E to this section.

(iv) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (p)(10)(i) of this section does not apply, you must calculate rod packing vent emissions from each reciprocating compressor using equation W–29E to this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (p).

$$E_{s,i,p} = EF_{s,p} \times \frac{T_p}{T_{total}} \times \frac{GHG_{i,p}}{GHG_{EF}} \quad \text{(Eq. W-29E)}$$

Where:

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for reciprocating compressor p, at standard conditions, in cubic feet.

$EF_{s,p}$ = Emission factor for reciprocating compressor p, in standard cubic feet per year. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

T_p = Total time reciprocating compressor p was in operating mode, for which $E_{s,i,p}$ is being calculated in the reporting year, in hours.

T_{total} = Total hours per year. Use 8784 in leap years and use 8760 in all other years.

$GHG_{i,p}$ = Mole fraction of GHG (either CH_4 or CO_2) in the vent gas for reciprocating compressor p in operating mode; use the appropriate gas compositions in paragraph (u)(2) of this section.

GHG_{EF} = Mole fraction of GHG (either CH_4 or CO_2) used in the determination of $EF_{s,p}$. Use 0.98 for CH_4 and 0.02 for CO_2.

* * * * *

(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) 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. Equipment leak components in vacuum service are exempt from the survey and emission estimation requirements of this paragraph (q).

(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, 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. For Reporting Year 2024, you may use data collected anytime during the calendar year for any of the applicable calculation methods, provided that the data were collected in accordance with and meet the criteria of the applicable paragraphs (q)(2) through (4) of this section.

(ii) For the components listed in § 98.232(d)(7) and (i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a)(1) through (5) 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), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), and (j)(10) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you must conduct surveys using any of the leak detection methods in § 98.234(a)(6) or (7) 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), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), or (j)(10), that are not subject to fugitive emissions standards in § 60.5397a 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)(1) through (5) for the surveyed component types in § 98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) 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), (f)(7), (g)(6), (h)(7), or (j)(10) 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)(1) through (5) for the surveyed component types in § 98.232(e)(8), (f)(6), (f)(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)(6) or (7) for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) that are not subject to fugitive emissions standards in § 60.5397a of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) using the emission calculation requirements in either paragraph (q)(2) or (3) of this section.

(2) *Calculation Method 1: Leaker emission factor calculation methodology.* If you elect not to measure leaks according to Calculation Method 2 as specified in paragraph (q)(3) of this section, you must use this Calculation Method 1 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 to this section and the requirements specified in paragraphs (q)(2)(i) through (xi) of this section. For the industry segment listed in § 98.230(a)(8), the results from equation W–30 to this section are used to calculate population emission factors on a meter/regulator run basis using equation W–31 to 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)(2)(x)(A) 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.

* * * * *

(3) *Calculation Method 2: Leaker measurement methodology.* 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, you may elect to measure the volumetric flow rate of each natural gas leak identified during a complete leak survey. If you elect to use this method, you must use this method for all components included in a complete leak survey and you must determine the volumetric flow rate of each natural gas leak identified during the leak survey and aggregate the emissions by the method of leak detection and component type as specified in paragraphs (q)(3)(i) through (vii) of this section. For an onshore petroleum and natural gas production facility electing to use this Calculation Method 2, a survey of all required components at a single well-pad site, as defined in § 98.238, will be considered a complete leak detection survey for purposes of this section. For an onshore petroleum and natural gas gathering and boosting facility electing to use this Calculation Method 2, a survey of all required components at a gathering and boosting site, as defined in § 98.238, will be considered a complete leak detection survey for purposes 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. If you are unable to measure the natural gas leak because it would require elevating the measurement personnel more than 2 meters above the surface and a lift is unavailable at the site or it would pose immediate danger to measurement personnel, then you must substitute the default leak rate for the component and site type from tables W–1E, W–2, W–3A, W–4A, W–5A, W–6A, and W–7 to this subpart, as applicable, as the measurement for this leak.

(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 by the method used for the survey for which a leak was detected.

(vii) Multiply the total CO_2 and CH_4 mass emissions by survey method and component type determined in paragraph (q)(3)(vi) by the survey specific value for ''k'', the factor adjustment for undetected leaks, where k equals 1.25 for the methods in § 98.234(q)(1), (3) and (5); k equals 1.55 for the method in § 98.234(q)(2)(i); and k equals 1.27 for the method in § 98.234(q)(2)(ii).

(viii) For natural gas distribution facilities:

(A) Use equation W–31 to 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 sum of the GHG volumetric emissions for each type of component required to be surveyed by the method used for the survey for which a leak was detected calculated in paragraph (q)(3)(iv) of this section rather than the emissions calculated using equation W–30 to this section.

(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)(viii) of this section, you must use the meter/regulator run population emission factors calculated according to paragraph (q)(3)(viii)(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 to this section.

(4) *Development of facility-specific component-level leaker emission factors by leak detection method.* If you elect to measure leaks according to Calculation Method 2 as specified in paragraph

(q)(3) of this section, you must use the measurement values determined in accordance with paragraph (q)(3) of this section to calculate a facility-specific component-level leaker emission factor by leak detection method as provided in paragraphs (q)(4)(i) through (iv) of this section.

(i) You must track the leak measurements made separately for each of the applicable components listed in paragraphs (q)(1)(i) through (v) of this section and by the leak detection method according to the following three bins.

(A) Method 21 as specified in § 98.234(a)(2).

(B) Method 21 as specified in § 98.234(a)(7).

(C) Optical gas imaging (OGI) and other leak detection methods as specified in § 98.234(a)(1) or (3) through (6).

(ii) You must accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a facility-specific component-level leaker emission factor for use in calculating emissions according to paragraph (q)(2) of this section (Calculation Method 1: Leaker emission factor calculation methodology).

(iii) Sum the volumetric flow rate of natural gas determined in accordance with paragraph (q)(3)(i) of this section for each leak by component type and leak detection method as specified in paragraph (q)(4)(i) of this section meeting the minimum number of measurement requirement in paragraph (q)(4)(ii) of this section.

(iv) Convert the volumetric flow rate of natural gas determined in paragraph (q)(4)(iii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(v) Determine the emission factor in units of standard cubic feet per hour component (scf/hr-component) by dividing the sum of the volumetric flow rate of natural gas determined in paragraph (q)(4)(iv) of this section by the total number of leak measurements for that component type and leak detection method combination.

(vi) You must update the emission factor determined in (q)(4)(v) of this section annually to include the results from all complete leak surveys for which leak measurement was performed during the reporting year in accordance with paragraph (q)(3) of this section.

* * * * *

(s) * * *

(1) Offshore production facilities under BOEMRE jurisdiction shall calculate emissions as specified in paragraph (s)(1)(i) or (ii) of this section, as applicable.

(i) Report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(ii) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, calculate emissions as specified in paragraph (s)(1)(i) of this section or adjust the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS) based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(2) Offshore production facilities that are not under BOEMRE jurisdiction must calculate emissions as specified in paragraph (s)(2)(i) or (ii) of this section, as applicable.

(i) Use the most recent monitoring methods and calculation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report annual emissions (GOADS).

(ii) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, you may calculate emissions as specified in paragraph (s)(2)(i) of this section or 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.

* * * * *

(z) * * *

(1) If a fuel combusted in the stationary or portable equipment is listed in table C–1 to subpart C of this part, or is a blend containing one or more fuels listed in table C–1, calculate emissions according to paragraph (z)(1)(i) of this section. If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation method described in paragraph (z)(1)(i) of this section and you may use the emission factor provided for natural gas as listed in table C–1. If the fuel combusted is natural gas, has a minimum higher heating value of 950 Btu per standard cubic foot, has a maximum higher heating value of 1,100 Btu per standard cubic foot, and has a minimum methane content of at least 70 percent, use the calculation method described in paragraph (z)(1)(iii) of this section. If the fuel is natural gas and does not meet the specifications of this paragraph (z)(1), calculate emissions according to paragraph (z)(2) of this section. If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to paragraph (z)(2) of this section.

* * * * *

(iii) For natural gas with a minimum higher heating value of 950 Btu per standard cubic foot, a maximum higher heating value of 1,100 Btu per standard cubic foot, and a minimum methane content of at least 70 percent, calculate CO_2, CH_4, and N_2O emissions for each unit or group of units combusting the same fuel according to Tier 2, Tier 3, or Tier 4 listed in 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.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that does not met the criteria of paragraph (z)(1) of this section, calculate combustion emissions as follows:

* * * * *

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you may use engineering estimates based on best available data to determine the concentration of each 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 as specified in the applicable paragraph in (u)(2) of this section.

* * * * *

■ 13. Revise and republish § 98.233 to read as follows

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For calculations that specify measurements in actual conditions, reporters may use a flow or volume measurement system that corrects to standard conditions and determine the flow or volume at standard conditions; otherwise, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 emissions from natural gas pneumatic device venting using the applicable provisions as specified in this paragraph (a) of this section. If you have a continuous flow meter on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices or natural gas driven pneumatic pumps vented directly to the atmosphere for any portion of the year, you must use the method specified in paragraph (a)(1) of this section to calculate CH_4 and CO_2 emissions from those devices. For natural gas pneumatic devices vented directly to the atmosphere for which the natural gas supply rate is not continuously measured, use the applicable methods specified in paragraphs (a)(2) through (7) of this section to calculate CH_4 and CO_2 emissions. For natural gas pneumatic devices that are routed to flares, combustion, or vapor recovery systems, use the applicable provisions specified in paragraphs (a)(8) of this section. All references to natural gas pneumatic devices for Calculation Method 1 in this paragraph (a) also apply to combinations of natural gas pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line.

(1) *Calculation Method 1.* If you have or elect to install a continuous flow meter that is capable of meeting the requirements of § 98.234(b) on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices and natural gas driven pneumatic pumps that are vented directly to the atmosphere, you must use the applicable methods specified in paragraph (a)(1)(i) through (iv) of this section to calculate CH_4 and CO_2 emissions from those devices.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are routed to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual volumetric flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, calculate the total volumetric flow for the year based on the measured volumetric flow times the total hours in the calendar year the devices were in service (*i.e.,* supplied with natural gas) divided by the number of hours the devices were in service (*i.e.,* supplied with natural gas) and the volumetric flow was being measured.

(B) Convert the natural gas volumetric flow from paragraph (a)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (a)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are vented directly to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual mass flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, calculate the total mass flow for the year based on the measured mass flow times the total hours in the calendar year the devices were in service (*i.e.,* supplied with natural gas) divided by the number of hours the devices were in service (*i.e.,* supplied with natural gas) and the mass flow was being measured.

(B) Convert the cumulative mass flow from paragraph (a)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(iii) If the flow meter on the natural gas supply line serves both natural gas pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data.

(iv) The flow meter must be operated and calibrated according to the methods set forth in § 98.234(b).

(2) *Calculation Method 2.* Except as provided in paragraph (a)(1) of this section, you may elect to measure the volumetric flow rate of each natural gas pneumatic device vent that vents directly to the atmosphere at your well-pad site, gathering and boosting site, or facility as specified in paragraphs (a)(2)(i) through (ix) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be measured or for which emissions are calculated according to the requirements in this paragraph (a)(2).

(i) For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you may elect to measure your pneumatic devices according to this Calculation Method 2 for some well-pad sites or gathering and boosting sites and use other methods for other sites. When you elect to measure the emissions from natural gas pneumatic devices according to this Calculation Method 2 at a well-pad site or gathering and boosting site, you must measure all natural gas pneumatic devices that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year and you must measure and calculate emissions according to the provisions in paragraphs (a)(2)(iii) through (viii) of this section.

(ii) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments electing to use this Calculation Method 2, you must measure all natural gas pneumatic devices vented directly to the atmosphere at your facility each year or, if your facility has 26 or more pneumatic devices, over multiple years, not to exceed the number of years as specified in paragraphs (a)(2)(ii)(A) through (D) of this section. If you elect to measure your pneumatic devices over multiple years, you must measure approximately the same number of devices each year. You must measure and calculate emissions for natural gas pneumatic devices at your facility according to the provisions in paragraphs (a)(2)(iii) through (ix), as applicable.

(A) If your facility has at least 26 but not more than 50 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 2 years.

(B) If your facility has at least 51 but not more than 75 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 3 years.

(C) If your facility has at least 76 but not more than 100 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 4 years.

(D) If your facility has 101 or more natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 5 years.

(iii) For all industry segments, determine the volumetric flow rate of each natural gas pneumatic device vent (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (a)(2)(iii)(A) through (E) of this section. You must measure the emissions under representative conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the device or manually actuating the device.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth in § 98.234(d), you must measure the emissions from each device for a minimum of 15 minutes while the device is in service (i.e., supplied with natural gas), except for natural gas pneumatic isolation valve actuators. For natural gas pneumatic isolation valve actuators, you must measure the emissions from each device for a minimum of 5 minutes while the device is in service (*i.e.,* supplied with natural gas). If there is no measurable flow from the natural gas pneumatic device after the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c) except you need only fill one bag to have a valid measurement. You must collect sample for a minimum of 5 minutes for natural gas pneumatic isolation valve actuators or 15 minutes for other natural gas pneumatic devices. If no gas is collected in the calibrated bag during the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section. If gas is collected in the bag during the minimum sampling period, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (a)(2)(iii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas pneumatic device vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section.

(E) If there is measurable flow from the device vent, calculate the volumetric flow rate of each natural gas pneumatic device vent (in standard cubic feet per hour) by dividing the cumulative volume of natural gas measured during the measurement period (in standard cubic feet) by the duration of the measurement (in hours).

(iv) For all industry segments, if there is measurable flow from the device vent, calculate the volume of natural gas emitted from each natural gas pneumatic device vent as the product of the natural gas flow rate measured in paragraph (a)(2)(iii) of this section and the number of hours the pneumatic device was in service (*i.e.,* supplied with natural gas) in the calendar year.

(v) For all industry segments, if there is no measurable flow from the device vent, estimate the emissions from the device according to the methods in paragraphs (a)(2)(v)(A) through (C) of this section, as applicable.

(A) For continuous high bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(*2*) Confirm that the device is correctly characterized as a continuous high bleed pneumatic device according to the provisions in paragraph (a)(6) of this section. If the device type was mischaracterized, recharacterize the device type and use the appropriate methods in paragraph (a)(2)(v)(B) or (C) of this section, as applicable.

(*3*) Upon confirmation of the items in paragraphs (a)(2)(v)(A)(*1*) and (*2*) of this section, remeasure the device vent using a different measurement method specified in § 98.234(b) through (d) or longer monitoring duration until there is a measurable flow from the device and calculate the natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(B) For continuous low bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(*2*) Determine natural gas bleed rate (in standard cubic feet per hour) at the supply pressure used for the pneumatic device based on the manufacturer's steady state natural gas bleed rate reported for the device. If the steady state bleed rate is reported in terms of air consumption, multiply the air consumption rate by 1.29 to calculate the steady state natural gas bleed rate. If a steady state bleed rate is not reported, follow the requirements in paragraph (a)(2)(v)(B)(*4*) of this section.

(*3*) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the natural gas steady state bleed rate determined in paragraph (a)(2)(v)(B)(*2*) of this section and number of hours the pneumatic device was in service (*i.e.*, supplied with natural gas) in the calendar year.

(*4*) If a steady state bleed rate is not reported, reassess whether the device is correctly characterized as a continuous low bleed pneumatic device according to the provisions in paragraph (a)(7) of this section. If the device is confirmed to be a continuous low bleed pneumatic device, you must remeasure the device vent using a different measurement method specified in § 98.234(b) through (d) or longer monitoring duration until there is a measurable flow from the device and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section. If the device type was mischaracterized, recharacterize the device type and use the appropriate methods in paragraph (a)(2)(v)(A) or (C) of this section, as applicable.

(C) For intermittent bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions according to paragraph (a)(2)(iv) of this section. For devices confirmed to be in-service during the measurement period, calculate natural gas emissions according to paragraphs (a)(2)(v)(C)(*2*) through (*5*) of this section.

(*2*) Calculate the volume of the controller, tubing and actuator (in actual cubic feet) based on the device and tubing size.

(*3*) Sum the volumes in paragraph (a)(2)(v)(C)(*2*) of this section and convert the volume to standard cubic feet following the methods specified in paragraph (t)(1) of this section based on the natural gas supply pressure.

(*4*) Estimate the number of actuations during the year based on company records, if available, or best engineering estimates. For isolation valve actuators, you may multiply the number of valve closures during the year by 2 (one actuation to close the valve; one actuation to open the valve).

(*5*) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the per actuation volume in standard cubic feet determined in paragraph (a)(2)(v)(C)(3) of this section, the number of actuations during the year as determined in paragraph (a)(2)(v)(C)(*4*) of this section, and the relay correction factor. Use 1 for the relay correction factor if there is no relay; use 3 for the relay correction factor if there is a relay.

(vi) For each pneumatic device, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (a)(2)(iv) or (v) of this section, as applicable, to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(vii) For each pneumatic device, convert the GHG volumetric emissions at standard conditions determined in paragraph (a)(2)(vi) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(viii) Sum the CO_2 and CH_4 mass emissions determined in paragraph (a)(2)(vii) of this section separately for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(ix) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments, if you chose to conduct natural gas pneumatic device measurements over multiple years, ''n,'' according to paragraph (a)(2)(ii) of this section, then you must calculate the emissions from all pneumatic devices at your facility as specified in paragraph (a)(2)(ix)(A) through (E) of this section.

(A) Use the emissions calculated in (a)(2)(viii) of this section for the devices measured during the reporting year.

(B) Calculate the whole gas emission factor for each type of pneumatic device at the facility using equation W–1A to this section and all available data from the current year and the previous years in your monitoring cycle (n-1 years) for which natural gas pneumatic device vent measurements were made according to Calculation Method 2 in paragraph (a)(2) of this section (*e.g.,* if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_t = \frac{\sum_{y=1}^{n} MT_{s,t,y}}{\sum_{y=1}^{n} Count_{t,y}} \qquad \text{(Eq. W-1A)}$$

Where:

EF_t = Whole gas population emission factor for natural gas pneumatic device vents of type ''t'' (continuous high bleed, continuous low bleed, intermittent bleed), in standard cubic feet per hour per device.

$MT_{s,t,y}$ = Volumetric whole gas emissions rate measurement at standard (''s'') conditions from component type ''t'' during year ''y'' in standard cubic feet per hour, as calculated in paragraph (a)(2)(iii) [if there was measurable flow from the device vent], (a)(2)(v)(B)(*2*), or (a)(2)(v)(C)(*6*) of this section, as applicable.

$Count_{t,y}$ = Count of natural gas pneumatic device vents of type ''t'' measured according to Calculation Method 2 in year ''y.''

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic device vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices that were not measured during the reporting year using equation W–1B to this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1B)}$$

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 paragraphs (a)(5) through (7) of this section that vent directly to the atmosphere and that were not directly measured according to the requirements in paragraph (a)(1) or (a)(2)(iii) 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'' (continuous high bleed, continuous low bleed, intermittent bleed) as calculated using equation W–1A to this section.

GHG_i = Concentration of GHG_i CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraph (u)(2) 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.

(D) Convert the volumetric emissions calculated using equation W–1B to this section to CH_4 and CO_2 mass emissions using the methods specified in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (a)(2)(ix)(A) and (D) of this section separately for each type of pneumatic device (continuous high bleed, continuous low bleed, intermittent bleed) to calculate the total CH_4 and CO_2 mass emissions by device type for Calculation Method 2.

(3) *Calculation Method 3.* For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you may elect to use the applicable methods specified in paragraphs (a)(3)(i) through (iv) of this section, as applicable, to calculate CH_4 and CO_2 emissions from your natural gas pneumatic devices that are vented directly to the atmosphere at your site except those that are measured

according to paragraph (a)(1) or (2) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be monitored or for which emissions are calculated according to the requirements in this paragraph (a)(3). You may not use this Calculation Method 3 for those well-pad sites or gathering and boosting sites for which you elected to measure emissions according to paragraph (a)(2) of this section.

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere, you must calculate CH_4 and CO_2 volumetric emissions using either the methods in paragraph (a)(3)(i)(A) or (B) of this section.

(A) Measure all continuous high bleed and continuous low bleed pneumatic devices at your well-pad site or gathering and boosting site, as applicable, according to the provisions in paragraphs (a)(2) of this section.

(B) Use equation W–1B to this section, except use the appropriate default whole gas population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ‘‘t’’ (continuous high bleed and continuous low bleed) as listed in table W–1 to this subpart.

(ii) For intermittent bleed pneumatic devices, you must monitor each intermittent bleed pneumatic device at your well-pad site or gathering and boosting site as specified in paragraphs (a)(3)(ii)(A) through (C) of this section, as applicable.

(A) You must use one of the monitoring methods specified in § 98.234(a)(1) through (3) except that the monitoring dwell time for each device vent must be at least 2 minutes or until a malfunction is identified, whichever is shorter. A device is considered malfunctioning if any leak is observed when the device is not actuating or if a leak is observed for more than 5 seconds, or the extended duration as specified in paragraph (a)(3)(ii)(C) of this section if applicable, during a device actuation. If you cannot tell when a device is actuating, any observed leak from the device indicates a malfunctioning device.

(B) If you elect to monitor emissions from natural gas pneumatic devices at a well-pad site or gathering and boosting site according to this Calculation Method 3, you must monitor all natural gas intermittent bleed pneumatic devices that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year. You must monitor the natural gas intermittent bleed pneumatic devices under conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the device or manually actuating the device.

(C) For certain throttling pneumatic devices or isolation valve actuators on pipes greater than 5 inches in diameter, that may actuate for more than 5 seconds under normal conditions, you may elect to identify individual devices for which longer bleed periods may be allowed as specified in paragraphs (a)(3)(ii)(C)(*1*) and (*2*) of this section prior to monitoring these devices for the first time.

(*1*) You must identify the devices for which extended actuations are considered normal operations. For each device identified, you must determine the typical actuation time and maintain documentation and rationale for the extended actuation duration value.

(*2*) You must clearly and permanently tag the device vent for each natural gas pneumatic device that has an extended actuation duration. The tag must include the device ID and the normal duration period (in seconds) as determined and documented for the device as specified in paragraph (a)(3)(ii)(C)(1) of this section.

(iii) For intermittent bleed pneumatic devices that are monitored according to paragraph (a)(3)(ii) of this section during the reporting year, you must calculate CH_4 and CO_2 volumetric emissions from intermittent bleed natural gas pneumatic devices vented directly to the atmosphere using equation W–1C to this section.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x} \left\{ K_1 \times T_{mal,z} + K_2 \times \left(T_{t,z} - T_{mal,z} \right) \right\} + \left(K_2 \times Count \times T_{avg} \right) \right] \qquad \text{(Eq. W-1C)}$$

Where:

E_i = Annual total volumetric emissions of GHGi from intermittent bleed natural gas pneumatic devices in standard cubic feet.

GHG_i = Concentration of GHGi, CH_4 or CO_2, in natural gas supplied to the intermittent bleed natural gas pneumatic device as defined in paragraph (u)(2) of this section.

x = Total number of intermittent bleed natural gas pneumatic 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.

K_1 = Whole gas emission factor for malfunctioning intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device. Use 24.1 for well-pad sites in the onshore petroleum and natural gas production industry segment and use 16.1 for gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segment.

$T_{mal,z}$ = The total time the surveyed pneumatic device ‘‘z’’ was in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning, 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.

$T_{t,z}$ = The total time the surveyed natural gas pneumatic device ‘‘z’’ was in service (*i.e.,* supplied with natural gas) during the year. Default is 8,760 hours for non-leap years and 8,784 hours for leap years.

K_2 = Whole gas emission factor for properly operating intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device. Use 0.3 for well-pad sites in the onshore petroleum and natural gas production industry segment and use 2.8 for gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segment.

Count = Total number of intermittent bleed natural gas pneumatic devices that were never observed to be malfunctioning during any monitoring survey during the year.

T_{avg} = The average time the intermittent bleed natural gas 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 for non-leap years and 8,784 hours for leap years.

(A) 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–1C to this section.

(B) For the purposes of paragraph (a)(3)(iii)(A) of this section, a complete monitoring survey is a survey of all intermittent bleed natural gas pneumatic devices vented directly to the atmosphere at a well-pad site for onshore petroleum and natural gas production facilities (except those measured according to paragraph (a)(1) of this section) or all intermittent bleed pneumatic devices vented directly to the atmosphere at a gathering and boosting site for onshore petroleum and natural gas gathering and boosting facilities (except those measured according to paragraph (a)(1) of this section).

(iv) You must convert the CH_4 and CO_2 volumetric emissions as determined according to paragraphs (a)(3)(i) and (iii) of this section and calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(4) *Calculation Method 4.* For well-pads in the onshore petroleum and natural gas production industry segment, gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segments, or for facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments, you may elect to calculate CH_4 and CO_2 emissions from your natural gas pneumatic devices that are vented directly to the atmosphere at your site using the methods specified in paragraphs (a)(4)(i) and (ii) of this section except those that are measured according to paragraphs (a)(1) through (3) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be monitored or for which emissions are calculated according to the requirements in this paragraph (a)(4). You may not use this Calculation Method 4 for those devices for which you elected to measure emissions according to paragraph (a)(1), (2), or (3) of this section.

(i) You must calculate CH_4 and CO_2 volumetric emissions using equation W–1B to this section, except use the appropriate default whole gas population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' (continuous high bleed, continuous low bleed, and intermittent bleed) as listed in table W–1 to this subpart.

(ii) You must convert the CH_4 and CO_2 volumetric emissions as determined according to paragraphs (a)(4)(i) of this section and calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(5) *Counts of natural gas pneumatic devices.* For all industry segments, determine ''Countt'' for equation W–1A, W–1B, or W–1C to this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the total number of devices at the well-pad site, gathering and boosting site, or facility, as applicable, the number of devices that are vented directly to the atmosphere and the number of those devices that were measured or monitored during the reporting year, as applicable, except as specified in paragraph (a)(6) of this section.

(6) *Counts of onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting natural gas pneumatic devices.* For facilities in the onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine the total number of natural gas pneumatic devices at the facility and the number of devices that are vented directly to the atmosphere for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed), as applicable, using engineering estimates based on best available data. Counts of natural gas pneumatic devices measured or monitored during the reporting year must be made based on actual counts.

(7) *Type of natural gas pneumatic devices.* For all industry segments, determine the type of natural gas pneumatic device using engineering estimates based on best available information.

(8) *Routing to flares, combustion, or vapor recovery systems.* Calculate emissions from natural gas pneumatic devices routed to flares, combustion, or vapor recovery systems as specified in paragraph (a)(8)(i) or (ii) of this section, as applicable. If a device was vented directly to the atmosphere for part of the year and routed to a flare, combustion unit, or vapor recovery system during another part of the year, then calculate emissions from the time the device vents directly to the atmosphere as specified in paragraph (a)(1), (2), (3) or (4) of this section, as applicable, and calculate emissions from the time the device was routed to a flare or combustion as specified in paragraph (a)(8)(i) or (ii) of this section, as applicable. During periods when natural gas pneumatic device emissions are collected in a vapor recovery system that is not routed to combustion, paragraphs (a)(1) through (4) and (a)(8)(i) and (ii) of this section do not apply and no emissions calculations are required. Notwithstanding the calculation and emissions reporting requirements as specified in this paragraph (a)(8) of this section, the number of natural gas pneumatic devices routed to flares, combustion, or vapor recovery systems, by type, must be reported as specified in § 98.236(b)(2)(iii).

(i) If any natural gas pneumatic devices 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).

(ii) If emissions from any natural gas pneumatic devices were routed to combustion units, you must calculate and report emissions as specified in subpart C of this part or calculate emissions as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z), as applicable.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pumps venting directly to the atmosphere as specified in paragraph (c)(1), (2), or (3) of this section, as applicable. If you have a continuous flow meter on the natural gas supply line that is dedicated to any one or more natural gas driven pneumatic pumps, each of which only vents directly to the atmosphere, you must use Calculation Method 1 as specified in paragraph (c)(1) of this section to calculate vented CH_4 and CO_2 emissions from those pumps. Use Calculation Method 1 for any portion of a year when all of the pumps on the continuously measured natural gas supply line were vented directly to atmosphere. For natural gas driven pneumatic pumps vented directly to the atmosphere for which the natural gas supply rate is not continuously measured or the continuously measured natural gas supply line supplies some natural gas driven pneumatic pumps that vent emissions directly to the atmosphere and others that route emissions to flares, combustion or vapor recovery, use either the method specified in paragraph (c)(2) or (3) of this section to calculate vented CH_4 and CO_2 emissions for all of the natural gas driven pneumatic pumps at your facility that are not subject to Calculation Method 1; you may not use Calculation Method 2 for some vented natural gas driven pneumatic pumps and Calculation Method 3 for other natural gas driven pneumatic pumps. Calculate emissions from natural gas driven pneumatic pumps routed to flares or combustion as specified in paragraph (c)(4) of this section. All references to natural gas driven pneumatic pumps for Calculation Method 1 in this paragraph (c) also apply to combinations of natural gas pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line. 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) *Calculation Method 1.* If you have or elect to install a continuous flow meter that is capable of meeting the requirements of § 98.234(b) of this subpart on a supply line to natural gas driven pneumatic pumps, then for the period of the year when the natural gas supply line is dedicated to any one or more natural gas driven pneumatic pumps, and each of the pumps is vented directly to the atmosphere, you must use the applicable methods specified in paragraphs (c)(1)(i) or (ii) of this section to calculate vented CH_4 and CO_2 emissions from those pumps.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total volumetric flow for the year based on the measured volumetric flow times the total hours in the calendar year in which at least one of the pumps connected to the supply line was pumping liquid divided by the number of hours in the year when at least one of pumps connected to the supply line was pumping liquid and the volumetric flow was being measured.

(B) Convert the natural gas volumetric flow from paragraph (c)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (c)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total mass flow of vented natural gas emissions for the year based on the measured mass flow times the total hours in the calendar year in which at least one of the pumps connected to the supply line was pumping liquid divided by the number of hours in the year when at least one of pumps connected to the supply line was pumping liquid and the mass flow was being measured.

(B) Convert the cumulative mass flow from paragraph (c)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(iii) If the supply line serves both natural gas pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to natural gas pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data.

(iv) The flow meter must be operated and calibrated according to the methods set forth in § 98.234(b).

(2) *Calculation Method 2.* Except as provided in paragraph (c)(1) of this section, you may elect to measure the volumetric flow rate of each natural gas driven pneumatic pump at your facility that vents directly to the atmosphere as specified in paragraphs (c)(2)(i) through (vii) of this section. You must exclude the counts of pumps measured according to paragraph (c)(1) of this section from the counts of pumps to be measured and for which emissions are calculated according to the requirements in this paragraph (c)(2).

(i) Measure all natural gas driven pneumatic pumps at your facility at least once every 5 years. If you elect to measure your pneumatic pumps over multiple years, you must measure approximately the same number of pumps each year. When you measure the emissions from natural gas driven pneumatic pumps at a well-pad site or gathering and boosting site, you must measure all pneumatic pumps that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year.

(ii) Determine the volumetric flow rate of each natural gas driven pneumatic pump (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (c)(2)(ii)(A) through (D) of this section. You must measure the emissions under representative conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the pump.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth in § 98.234(d), you must measure the emissions from each pump for a minimum of 5 minutes, during a period when the pump is continuously pumping liquid.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c), except under § 98.234(c)(2), only one bag must be filled to have a valid measurement. You must collect sample for a minimum of 5 minutes, or until the bag is full, whichever is shorter, during a period when the pump is continuously pumping liquid. If the bag is not full after 5 minutes, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (c)(2)(ii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas driven pneumatic pump vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section. Convert the measured flow during the test period to standard cubic feet per hour, as appropriate.

(iii) Calculate the volume of natural gas emitted from each natural gas driven pneumatic pump vent as the product of the natural gas emissions flow rate measured in paragraph (c)(2)(ii) of this section and the number of hours that liquid was pumped by the pneumatic pump in the calendar year.

(iv) For each pneumatic pump, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (c)(2)(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 pneumatic pump, convert the GHG volumetric emissions at standard conditions determined in paragraph (c)(2)(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 (c)(2)(v) of this section.

(vii) If you chose to conduct natural gas pneumatic pump measurements over multiple years, ''n,'' according to paragraph (c)(2)(i) of this section, then you must calculate the emissions from all pneumatic pumps at your facility as specified in paragraph (c)(2)(vii)(A) through (D) of this section.

(A) Use the emissions calculated in paragraph (c)(2)(vi) of this section for the pumps measured during the reporting year.

(B) Calculate the whole gas emission factor for pneumatic pumps at the facility using equation W–2A to this section and all available data from the current year and the previous years in your monitoring cycle (n-1 years) for which natural gas pneumatic pump vent measurements were made according to Calculation Method 2 in paragraph (c)(2) of this section (*e.g.*, if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_s = \frac{\sum_{y=1}^{n} MT_{s,y}}{\sum_{y=1}^{n} Count_y} \qquad \text{(Eq. W-2A)}$$

Where:

EF_s = Whole gas population emission factor for natural gas pneumatic pump vents, in standard cubic feet per hour per pump.

$MT_{s,y}$ = Volumetric whole gas emissions rate measurement at standard (''s'') conditions during year ''y'' in standard cubic feet per hour, as calculated in paragraph (c)(2)(iii) of this section.

$Count_y$ = Count of natural gas driven pneumatic pump vents measured according to Calculation Method 2 in year ''y.''

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic pump vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps per well-pad site or gathering and boosting site that were not measured during the reporting year using equation W–2B to this section.

$$E_{s,i} = Count \times EF_s \times GHG_i \times T \qquad \text{(Eq. W-2B)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas driven pneumatic pump vents, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps that vented directly to the atmosphere and that were not directly measured according to the requirements in paragraphs (c)(1) or (c)(2)(ii) of this section.

EF_s = Population emission factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) as calculated using equation W–2A to this section.

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 pumping liquid using engineering estimates based on best available data. Default is 8,760 hours for pumps that only vented directly to the atmosphere.

(D) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions calculated using equation W–2B to this section using calculations in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (c)(2)(vii)(A) and (D) of this section to calculate the total CH_4 and CO_2 mass emissions for Calculation Method 2 per well-pad site or gathering and boosting site.

(3) *Calculation Method 3.* If you elect not to measure emissions as specified in Calculation Method 2, then you must use the applicable method specified in paragraphs (c)(3)(i) and (ii) of this section to calculate CH_4 and CO_2 emissions from all natural gas driven pneumatic pumps that are vented directly to the atmosphere at each well-pad site or gathering and boosting site at your facility and that are not measured according to paragraph (c)(1) of this section. You must exclude the counts of devices measured according to paragraph (c)(1) of this section from the counts of pumps for which emissions are calculated according to the requirements in this paragraph (c)(3).

(i) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps using equation W–2B to this section, except use the appropriate default whole gas population emission factor for natural gas pneumatic pump vents (in standard cubic feet per hour per device) as provided in table W–1 to this subpart.

(ii) Convert the CH_4 and CO_2 volumetric emissions determined according to paragraph (c)(3)(i) of this section to CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(4) *Routing to flares, combustion, or vapor recovery systems.* Calculate emissions from natural gas driven pneumatic pumps for periods when they are routed to flares or combustion as specified in paragraph (c)(4)(i) or (ii) of this section, as applicable. If emissions from a natural gas driven pneumatic pump were vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery for another part of the year, then calculate vented emissions for the portion of the year when venting occurs using the applicable method in paragraph (c)(1), (2), or (3) of this section for the period when venting occurs (including periods when emissions bypassed a flare), and calculate emissions for the portion of the year when the emissions are routed to a flare or combustion unit using the method in paragraph (c)(4) of this section. During periods when emissions from a pump are routed to a vapor recovery system without subsequently being routed to combustion, paragraphs (c)(1) through (3) and (c)(4)(i) and (ii) of this section do not apply and no emissions calculations are required. Notwithstanding the calculation and

emissions reporting requirements as specified in this paragraph (c)(4) of this section, the number of natural gas pneumatic pumps routed to flares, combustion, or vapor recovery systems must be reported as specified in § 98.236(c)(2)(iii) and (iv).

(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).

(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 unit (AGR) vents and Nitrogen removal unit (NRU) vents*. For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CH_4 and CO_2 vented directly to the atmosphere or emitted through a 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 (12) of this section, as applicable. For NRU vents, calculate emissions for CH_4 vented directly to the atmosphere 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) of this section, as applicable. If any AGR vents or NRU vents are 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). If any AGR vents or NRU vents are routed through an engine (*e.g.,* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement) (*i.e.*, routed to combustion), you must calculate CH_4, CO_2, and N_2O emissions as specified in subpart C of this part or as specified in paragraph (z) of this section, as applicable.

(1) *Calculation Method 1*. If you operate and maintain a continuous emissions monitoring system (CEMS) that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Method in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) *Calculation Method 2*. Except as specified in paragraph (d)(4) of this section, for CO_2 emissions, if a CEMS is not available but a vent meter is installed, use the CO_2 composition and annual volume of vent gas to calculate emissions using equation W–3 to this section. Except as specified in paragraph (d)(4) of this section, for CH_4 emissions, if a vent meter is installed, including the volumetric flow rate monitor on a CEMS for CO_2, use the CH_4 composition and annual volume of vent gas to calculate emissions using equation W–3 to this section.

$$E_{a,i} = V_a \times Vol_i \qquad \text{(Eq. W-3)}$$

Where:

$E_{a,i}$ = Annual total volumetric GHGi (either CO_2 or CH_4) emissions at actual conditions, in cubic feet per year.

V_a = Total annual volume of vent gas flowing out of the AGR or NRU in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

Vol_i = Annual average volumetric fraction of GHGi (either CO_2 or CH_4) content in vent gas flowing out of the AGR or NRU as determined in paragraph (d)(7) of this section.

(3) *Calculation Method 3*. If a CEMS for CO_2 or a vent meter is not installed, you may use the inlet and/or outlet gas flow rate of the AGR or NRU to calculate emissions for CH_4 and CO_2 using equation W–4A, W–4B, or W–4C to this section. If inlet gas flow rate and CH_4 and CO_2 content of the vent gas are known, use equation W–4A to this section. If outlet gas flow rate and CH_4 and CO_2 content of the vent gas are known, use equation W–4B to this section. If inlet gas flow rate and outlet gas flow rate are known, use equation W–4C to this section. If the calculated annual total volumetric emissions (Ea,i) are less than or equal to 0 cubic feet per year, you may not use this calculation method for either CH_4 or CO_2.

$$E_{a,i} = V_{in} \times \left[\frac{Vol_{I,i} - Vol_{O,i}}{Vol_{EM,i} - Vol_{O,i}}\right] \times Vol_{EM,i} \qquad \text{(Eq. W-4A)}$$

$$E_{a,i} = V_{out} \times \left[\frac{Vol_{I,i} - Vol_{O,i}}{Vol_{EM,i} - Vol_{I,i}}\right] \times Vol_{EM,i} \qquad \text{(Eq. W-4B)}$$

$$E_{a,i} = \left(V_{in} \times Vol_{I,i}\right) - \left(V_{out} \times Vol_{O,i}\right) \qquad \text{(Eq. W-4C)}$$

Where:

$E_{a,i}$ = Annual total volumetric GHG_i (either CH_4 or CO_2) emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR or NRU in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

V_{out} = Total annual volume of natural gas flow out of the AGR or NRU in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

$Vol_{I,i}$ = Annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in natural gas flowing into the AGR or NRU as determined in paragraph (d)(7) of this section.

$Vol_{O,i}$ = Annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in natural gas flowing out of the AGR or NRU as determined in paragraph (d)(8) of this section.

$Vol_{EM,i}$ = Annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in the vent gas flowing out of the AGR or NRU as determined in paragraph (d)(6) of this section.

(4) *Calculation Method 4.* If CEMS for CO_2 or a vent meter is not installed, you may calculate CH_4 and CO_2 emissions from an AGR or NRU using any standard simulation software package, such as AspenTech HYSYS®, or API 4679 AMINECalc, that uses the Peng-Robinson equation of state and speciates CH_4 and CO_2 emissions. A minimum of the parameters listed in paragraph (d)(4)(i) through (x) of this section, as applicable, must be used to characterize emissions. If paragraph (d)(4)(i) through (x) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions over the time period covered by the simulation. Determine all other applicable parameters in paragraph (d)(4)(i) through (x) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.*, if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year). You may also use this method for CO_2 emissions from an AGR if a vent meter is installed but a CEMS is not, or for CH_4 emissions from an AGR if a vent meter is installed (including the volumetric flow rate monitor on a CEMS for CO_2), in which case you must determine the difference between the annual volume of vent gas measured by the vent meter and the simulated annual volume of vent gas according to paragraph (d)(9) of this section.

(i) Natural gas feed temperature, pressure, and flow rate (must be measured).

(ii) Acid gas content of feed natural gas (must be measured).

(iii) Acid gas content of outlet natural gas.

(iv) CH_4 content of feed natural gas (must be measured).

(v) CH_4 content of outlet natural gas.

(vi) For NRU, nitrogen content of feed natural gas (must be measured).

(vii) For NRU, nitrogen content of outlet natural gas.

(viii) Unit operating hours, excluding downtime for maintenance or standby.

(ix) Exit temperature of natural gas.

(x) For AGR, solvent type, pressure, temperature, circulation rate, and composition.

(5) *Flow rate of inlet or outlet.* For Calculation Method 3, determine the gas flow rate of the inlet when using equation W–4A or W–4C to this section or the gas flow rate of the outlet when using equation W–4B or W–4C to this section for the natural gas stream of an AGR or NRU using a meter according to methods set forth in § 98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) *Composition of vent gas.* For Calculation Method 2 or Calculation Method 3 when using equation W–4A or W–4B to this section, if a continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream for each quarter that the AGR or NRU is operating to determine Vol_i in equation W–3 to this section or $Vol_{EM,i}$ in equation W–4A or W–4B to this section, according to the methods set forth in § 98.234(b).

(7) *Composition of inlet gas stream.* For Calculation Method 3, if a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream for each quarter that the AGR or NRU is operating to determine VolI,i in equation W–4A, W–4B, or W–4C to this section, according to the methods set forth in § 98.234(b).

(8) *Composition of outlet gas stream.* For Calculation Method 3, determine annual average volumetric fraction of GHGi (either CH_4 or CO_2) content in natural gas flowing out of the AGR or NRU using one of the methods specified in paragraphs (d)(8)(i) through (iii) of this section.

(i) If a continuous gas analyzer is installed on the outlet natural gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet natural gas stream for each quarter that the AGR or NRU is operating to determine $Vol_{O,i}$ in equation W–4A, W–4B, or W–4C to this section, according to the methods set forth in § 98.234(b).

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas and the outlet quality specification for CH_4 in natural gas.

(9) Comparison of annual volume of vent gas. If a vent meter is installed but you wish to use Calculation Method 4 rather than Calculation Method 2 for an AGR, use equation W–4D to this section to determine the difference between the annual volume of vent gas measured by the vent meter and the simulated annual volume of vent gas.

$$PD = \frac{\left|V_{a,meter} - V_{a,sim}\right|}{\left(\frac{V_{a,meter} + V_{a,sim}}{2}\right)} \times 100\% \qquad \text{(Eq. W-4D)}$$

Where:

PD = Percent difference between vent gas volumes, %.

$V_{a,meter}$ = Total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

$V_{a,sim}$ = Total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by a standard simulation software package consistent with paragraph (d)(4) of this section.

(10) *Volumetric emissions.* Calculate annual volumetric CH_4 and CO_2 emissions at standard conditions using calculations in paragraph (t) of this section.

(11) *Emissions vented directly to atmosphere from AGRs or NRUs routed to vapor recovery systems or flares.* If the AGR vent or NRU vent has a vapor recovery system or routes emissions to a flare, calculate annual emissions vented directly to atmosphere from the AGR vent or NRU vent during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (d)(11)(i) and (ii) of this section. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(i) Calculate vented emissions as specified in paragraph (d)(1), (2), (3), or (4) of this section, which represents the emissions from the AGR vent or NRU vent prior to the vapor recovery system or flare. Calculate an average hourly vented emissions rate by dividing the vented emissions by the number of hours that the AGR or NRU was in operation.

(ii) To calculate vented emissions during periods when the AGR vent or NRU vent was not routing emissions to a vapor recovery system or a flare, multiply the average hourly vented emissions rate determined in paragraph (d)(11)(i) of this section by the number of hours that the AGR or NRU vented directly to the atmosphere. Determine the number of hours that the AGR or NRU vented directly to atmosphere by subtracting the hours that the AGR or NRU was connected to a vapor recovery system or flare (based on engineering estimate and best available data) from the total operating hours for the AGR or NRU in the calendar year. You must take into account periods with reduced capture efficiency of the vapor recovery system or flare.

(12) *Mass emissions.* Calculate annual mass CH_4 and CO_2 emissions using calculations in paragraph (v) of this section.

(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. For glycol dehydrators that have an annual average daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day, use Calculation Method 1 in paragraph (e)(1) of this section. For glycol dehydrators that have an annual average of 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, use either Calculation Method 1 in paragraph (e)(1) of this section or Calculation Method 2 in paragraph (e)(2) of this section. If you are required to use a software program consistent with the requirements of paragraph (e)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual emissions inventory reporting for the current reporting year, you must use Calculation Method 1 to calculate annual CH_4 and CO_2 emissions. If emissions from dehydrator vents are routed to a vapor recovery system, you must calculate the emissions according to paragraph (e)(4) of this section. If emissions from dehydrator vents are routed to a regenerator firebox/fire tubes, you must calculate CH_4, CO_2, and N2O annual emissions as specified in paragraph (e)(5) of this section. If any dehydrator vents are routed to a flare, you must calculate CH_4, CO_2, and N2O 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).

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators by using a software program, such as AspenTech HYSYS®, Bryan Research & Engineering ProMax@, or GRI–GLYCalcTM, 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. If you elect to use ProMax@, you must use version 5.0 or above. Emissions must be modeled from both the still vent and, if applicable, the flash tank vent. A minimum of the parameters listed in paragraph (e)(1)(i) through (xi) of this section, as applicable, must be used to characterize emissions. If paragraph (e)(1)(i) through (xi) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation. Sample and analyze composition at least once every five years. Samples must be collected within six months of the startup or by January 1, 2030, whichever date is later. Until such a time that a sample is collected, determine composition by using one of the existing methods. Determine all other applicable parameters in paragraph (e)(1)(i) through (xi) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (i.e., if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year). If more than one simulation is performed, input parameters should be remeasured if no longer representative of operating conditions.

(i) Feed natural gas flow rate (based on measured data).

(ii) Feed natural gas water content (must be measured).

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (e.g., natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type (e.g., triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG)).

(vii) Use of stripping gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure at the absorber inlet (must be measured).

(xi) Wet natural gas composition. Measure this parameter using one of the methods described in paragraphs (e)(1)(xi)(A) and (B) of this section.

(A) 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 specified in § 98.234(b) to sample and analyze wet natural gas composition.

(B) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) . Calculate annual volumetric emissions from glycol dehydrators using equation W–5 to 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:

$$E_{s,i} = EF_i * Count * 1000 \quad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

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 for which you elect to use this Calculation Method 2.

1000 = Conversion of EFi in thousand standard cubic feet to standard cubic feet.

(3) *Calculation Method 3.* For dehydrators of any size that use desiccant, you must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using equation W–6 to this section. From volumetric natural gas emissions, calculate both CH_4 and CO_2 volumetric and mass emissions using the procedures in paragraphs (u) and (v) of this section. Desiccant dehydrator emissions covered in this paragraph do not have to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

$$E_{s,n} = \frac{\left(H * D^2 * \pi * P_2 * \%G * N\right)}{(4 * P_1 * 100)} \quad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

π = pi (3.14).

%G = Percent of packed vessel volume that is gas.

N = Number of dehydrator openings in the calendar year.

100 = Conversion of %G to fraction.

(4) *Emissions vented directly to atmosphere from dehydrators routed to a vapor recovery system, flare, or regenerator firebox/fire tubes.* If the dehydrator(s) has a vapor recovery system, routes emissions to a flare, or routes emissions to a regenerator firebox/fire tubes and you use Calculation Method 1 or Calculation Method 2 in paragraph (e)(1) or (2) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes as specified in paragraphs (e)(4)(i) and (ii) of this section. If the dehydrator(s) has a vapor recovery system or routes emissions to a flare and you use Calculation Method 3 in paragraph (e)(3) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (e)(4)(iii) of this section.

(i) When emissions from dehydrator(s) are calculated using Calculation Method 1 or 2, calculate vented emissions as specified in paragraph (e)(1) or (2) of this section, which represents the emissions from the dehydrator prior to the vapor recovery system or flare. Calculate an average hourly vented emissions rate by dividing the vented emissions by the number of hours that the dehydrator was in operation.

(ii) To calculate total emissions vented directly to atmosphere during periods when the dehydrator was not routing emissions to a vapor recovery system, flare, or regenerator firebox/fire tubes for dehydrator(s) with emissions calculated using Calculation Method 1 or 2, multiply the average hourly vented emissions rate determined in paragraph (e)(4)(i) of this section by the number of hours that the dehydrator vented directly to the atmosphere. Determine the number of hours that the dehydrator vented directly to atmosphere by subtracting the hours that the dehydrator was connected to a vapor recovery system, flare, or regenerator firebox/fire tubes (based on engineering estimate and best available data) from the total operating hours for the dehydrator in the calendar year. You must take into account periods with reduced capture efficiency of the vapor recovery system, flare, or regenerator firebox/fire tubes. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(iii) When emissions from dehydrator(s) are calculated using Calculation Method 3, calculate total annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes by determining of the number of depressurization events (including portions of an event) that vented to atmosphere based on engineering estimate and best available data. You must take into account periods with reduced capture efficiency of the vapor recovery system or flare. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(5) *Combustion emissions from routing to regenerator firebox/fire tubes or other non-flare combustion unit.* If any glycol dehydrator emissions are routed to a regenerator firebox/fire tubes or other non-flare combustion unit, calculate emissions from these devices attributable to dehydrator flash tank vents or still vents as specified in paragraphs (e)(5)(i) through (iii) of this section. If any desiccant dehydrator emissions are routed to a non-flare combustion unit, calculate combusted emissions as specified in paragraphs (e)(5)(i) through (iii) of this section. If you operate a CEMS to monitor the emissions from the regenerator firebox/fire tubes or other non-flare combustion unit, calculate emissions as specified in paragraph (e)(5)(iv) of this section.

(i) Determine the volume of the total emissions that is routed to a regenerator firebox/fire tubes or other non-flare combustion unit as specified in paragraph (e)(5)(i)(A) or (B) of this section.

(A) Measure the flow from the dehydrator(s) to the regenerator firebox/fire tubes or other non-flare combustion unit using a continuous flow measurement device. If you continuously measure flow to the regenerator firebox/fire tubes or other non-flare combustion unit, you must use the measured volumes to calculate emissions from the regenerator firebox/fire tubes or other non-flare combustion unit.

(B) Using engineering estimates based on best available data, determine the volume of the total emissions estimated in paragraph (e)(1), (2), or (3) of this section, as applicable, that is routed to the regenerator firebox/fire tubes or other non-flare combustion unit.

(ii) Determine composition of the gas routed to a regenerator firebox/fire tubes or other non-flare combustion unit as specified in paragraph (e)(5)(ii)(A) or (B) of this section.

(A) Use the appropriate vent emissions as determined in paragraph (e)(1) or (2) of this section.

(B) Measure the composition of the gas from the dehydrator(s) to the regenerator firebox/fire tubes or other non-flare combustion unit using a continuous composition analyzer. If you continuously measure gas composition, then those measured data must be used to calculate dehydrator emissions from the regenerator firebox/fire tubes.

(iii) Determine GHG volumetric emissions at actual conditions from the regenerator firebox/fire tubes or other non-flare combustion unit using equations W–39A, W–39B, and W–40 to this section. Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section. Calculate both GHG mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(iv) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor for the combustion gases from the regenerator firebox/fire tubes or other non-flare combustion unit, you must calculate only CO_2 emissions for the regenerator firebox/fire tubes. You must follow the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate emissions from a regenerator firebox/fire tubes or other non-flare combustion unit, the requirements specified in paragraphs (e)(5)(ii) and (iii) of this section are not required.

(f) *Well venting for liquids unloadings.* Calculate annual volumetric natural gas emissions from well venting for liquids unloading when the well is unloaded to the atmosphere using one of the calculation methods described in paragraph (f)(1), (2), or (3) of this section. Calculate annual CH_4 and CO_2 volumetric and mass emissions using the method described in paragraph (f)(4) of this section. If emissions from well venting for liquids unloading are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(1) *Calculation Method 1.* Calculate emissions from manual and automated unloadings at wells with plunger lifts and wells without plunger lifts separately. For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see § 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented directly to the atmosphere to expel liquids accumulated in the tubing, install a recording flow meter on the vent line used to vent gas from the well (e.g., on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate the total emissions from well venting to the atmosphere for liquids unloading using equation W–7A to this section. Equation W–7A to this section must be used for each unloading type combination (automated plunger lift unloadings, manual plunger lift unloadings, automated unloadings without plunger lifts and manual unloadings without plunger lifts) for any tubing diameter group and pressure group combination in each sub-basin.

$$E_a = FR \times T_p \qquad \text{(Eq. W-7A)}$$

Where:

E_a = Annual natural gas emissions for each well of the same tubing diameter group and pressure group combination in the sub-basin at actual conditions, a, in cubic feet. Calculate emissions from wells with automated plunger lift unloadings, wells with manual plunger lift unloadings, wells with automated unloadings without plunger lifts and wells with manual unloadings without plunger lifts separately.

FR = Average flow rate in cubic feet per hour for all measured wells of the same tubing diameter group and pressure group combination in a sub-basin, over the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

T_p = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year. If the available venting data do not contain a record of the date of the venting events and data are not available to provide the venting hours for the specific time period of January 1 to December 31, you may calculate an annualized vent time, Tp, using equation W–7B to this section.

$$T_p = \frac{HR_p}{MP_p} \times D_p \qquad \text{(Eq. W-7B)}$$

Where:

HR_p = Cumulative amount of time in hours of venting for each well, p, during the monitoring period.

MP_p = Time period, in days, of the monitoring period for each well, p. A minimum of 300 days in a calendar year are required. The next period of data collection must start immediately following the end of data collection for the previous reporting year.

D_p = Time period, in days during which the well, p, was in production (365 if the well was in production for the entire year).

(i) Determine the well vent average flow rate (''FR'' in equation W–7A to this section) as specified in paragraphs (f)(1)(i)(A) through (C) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category. Calculate emissions from wells with automated plunger lift unloadings, wells with manual plunger lift unloadings, wells with automated unloadings without plunger lifts and wells with manual unloadings without plunger lifts separately.

(A) Calculate the average flow rate per hour of venting for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total annual flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) Apply the average hourly flow rate calculated under paragraph (f)(1)(i)(A) of this section to each well in the same pressure group that have the same tubing diameter group, for the number of hours of each well is venting to the atmosphere.

(C) Calculate a new average flow rate every other calendar year starting with the first calendar year of data collection. For a new producing sub-basin category, calculate an average flow rate beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Method 2.* Calculate the total emissions for each well from manual and automated well venting to the atmosphere for liquids unloading without plunger lift assist using equation W–8 to this section.

$$E_s = N_p \times \left(\left(0.37 \times 10^{-3}\right) \times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{N_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right) \times Z_{p,q}\right) \text{ (Eq. W-8)}$$

Where:

E_s = Annual natural gas emissions for each well at standard conditions, s, in cubic feet per year

N_p = Total number of unloading events in the monitoring period per well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p = Casing internal diameter for well, p, in inches or the tubing diameter for well, p, when stoppage packers are used in the annulus to restrict flow of gas up the annulus to the surface.

WD_p = Vertical well depth from either the top of the well or the lowest packer to the bottom of the well or the top of the fluid column, for well, p, in feet. For horizontal wells the bottom of the well is the point at which the vertical borehole pivots to a horizontal direction.

SP_p = For well, p, shut-in pressure or surface pressure for wells with tubing production, or casing pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure is not available for the well, you may determine the casing pressure by multiplying the tubing pressure of the well with a ratio of casing pressure to tubing pressure from a well in the same sub-basin for which the casing pressure is known. The tubing pressure must be measured during gas flow to a flow-line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading when the well production is impeded by liquids loading or closed to the flow-line by surface valves.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use equation W–33 to this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

q = Unloading event.

$Z_{p,q}$ = If HRp,q is less than 1.0 then Zp,q is equal to 0. If HRp,q is greater than or equal to 1.0 then Zp,q is equal to 1.

(3) Calculation Method 3. Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading with plunger lift assist using equation W–9 to this section.

$$E_s = N_p \times \left(\left(0.37 \times 10^{-3}\right) \times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{N_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right) \times Z_{p,q}\right) \text{ (Eq. W-9)}$$

Where:

E_s = Annual natural gas emissions for each well at standard conditions, s, in cubic feet per year.

N_p = Total number of unloading events in the monitoring period per well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD_p = Tubing internal diameter for well, p, in inches.

WD_p = Tubing depth to plunger bumper or to the top of the fluid column for well, p, in feet.

SP_p = Flow-line pressure for well p in pounds per square inch absolute (psia), using engineering estimate based on best available data.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use equation W–33 to this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that well, p, was left open to the atmosphere during each unloading event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

q = Unloading event.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

(4) *Volumetric and mass emissions.* Calculate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using equation W–10A or equation W–10B to this section. Equation W–10A to this section applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers in a sub-basin and well type combination and equation W–10B to this section applies when the gas flowback vent volume is measured for each completion or workover in a sub-basin and well type combination. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use equation W–10A to this section, you must follow the procedures specified in paragraph (g)(1) of this section. If you elect to use equation W–10B to this section, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. To calculate emissions during the initial period, you must calculate the gas flowback rate in the initial flowback period as described in equation W–10B to this section. Alternatively, you may use a multiphase flow meter placed on the flow line downstream of the wellhead and ahead of the separator to directly measure gas flowback during the initial period when flowback is routed to open pits or tanks. If you use a multiphase flow meter, measurements must be taken from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(g), as applicable.

$$E_{s,n} = \sum_{p=1}^{CW} \left[T_{p,s} \times FRM_s \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \times Z_{p,i} \times PR_{s,p} \right] \right] \qquad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{CW} \left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \times Z_{p,i} \right] \right] \qquad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each well.

CW = Total number of completions or workovers using hydraulic fracturing.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented for each completion or workover, in hours, during the reporting year. This may include non-contiguous periods of venting.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for each completion or workover, in hours, during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after each completion of a newly drilled well or well workover using hydraulic fracturing in standard cubic feet per hour that was measured in the sub-basin and well type combination. If applicable, PRs,p may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback during each completion or workover, as determined by using an appropriate meter according to methods described in § 98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did not inject gas into the reservoir or if the injected gas is CO_2 then EnFs,p is 0.

$FV_{s,p}$ = Flow volume of vented gas for each completion or workover, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

$FR_{p,i}$ = Flow rate vented of each completion or workover, in standard cubic feet per hour during the initial period when flowback is routed to open pits or tanks from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation, measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in § 98.234(b). Alternatively, flow rate during the initial period may be measured using a multiphase flow meter installed upstream of the separator capable of accurately measuring gas flow prior to separation.

$Z_{p,i}$ = If a multiphase flow meter is used to measure flowback during the initial period, then $Z_{p,i}$ is equal to 1. If flowback is measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, then $Z_{p,i}$ is equal to 0.5.

(1) If you elect to use equation W–10A to this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section. If you are unable to measure the gas flowback rates using a recording flow meter for gas well completions or workovers as described in Calculation Method 1, for example due to field conditions, operating conditions, or health and safety considerations, you may use Calculation Method 2 as specified in paragraph (g)(1)(ii) of this section to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete

measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

(i) *Calculation Method 1.* You must use equation W–12A to this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use equation W–12B to this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in equations W–12A and W–12B to this section, you must use a recording flow meter (digital or analog) installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in § 98.234(b). Alternatively, you may use a multiphase flow meter placed on the flow line downstream of the wellhead and ahead of the separator to directly measure gas flowback during the initial period when flowback is routed to open pits or tanks. If you use a multiphase flow meter, measurements must be taken from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation.

(ii) *Calculation Method 2 (for gas wells).* You must use equation W–12A to this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use equation W–12B to this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) also apply. When calculating the flowback rates for use in equations W–12A and W–12B to this section based on well parameters, you must record the well flowing pressure immediately upstream (and immediately downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate the well flowback. The upstream pressure must be surface pressure and reservoir pressure cannot be assumed. The downstream pressure must be measured after the choke and atmospheric pressure cannot be assumed. Calculate flowback rate using equation W–11A to this section for subsonic flow or equation W–11B to this section for sonic flow. You must use best engineering estimates based on best available data along with equation W–11C to this section to determine whether the predominant flow is sonic or subsonic. If the value of R in equation W–11C to this section is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic. Convert calculated FR_a values from actual conditions upstream of the restriction orifice to standard conditions ($FR_{s,p}$ and $FR_{i,p}$) for use in equations W–12A and W–12B to this section using equation W–33 to this section.

$$FR_a = 1.27*10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \qquad \text{(Eq. W-11A)}$$

Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

P_1 = Pressure immediately upstream of the choke (psia).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

P_2 = Pressure immediately downstream of the choke (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR_a = 1.27*10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. W-11B)}$$

Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$R = P1/P2 \qquad \text{(Eq. W-11C)}$$

Where:

R = Pressure ratio.

P_1 = Pressure immediately upstream of the choke (psia).

P_2 = Pressure immediately downstream of the choke (psia).

(iii) For equation W–10A to this section, calculate FRMs using equation W–12A to this section.

$$FRM_s = \frac{\sum_{p=1}^{N} FR_{s,p}}{\sum_{p=1}^{N} PR_{s,p}} \qquad \text{(Eq. W-12A)}$$

Where:

FRM_s = Ratio of average gas flowback rate, during the period of time when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or calculated average flowback rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured and calculated FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using equation W–33 to this section. You may not use flow volume as used in equation W–10B to this section converted to a flow rate for this parameter.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(iv) For equation W–10A to this section, calculate FRMi using equation W–12B to this section.

$$FRM_i = \frac{\sum_{p=1}^{N} FR_{i,p}}{\sum_{p=1}^{N} PR_{s,p}} \qquad \text{(Eq. W-12B)}$$

Where:

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, for the period of flow to open tanks/pits.

$FR_{i,p}$ = Initial measured gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or initial calculated flow rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section in standard cubic feet per hour for well(s), p, for each sub-basin and well type combination. Measured and calculated $FR_{i,p}$ values must be based on flow conditions at the beginning of the separation period and must be expressed at standard conditions or measured using a multiphase flow meter installed upstream of the separator capable of accurately measuring gas flow prior to separation.

$PR_{s,p}$ = Average gas production flow rate during the first 30-days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour of each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(v) For equation W–10A to this section, the ratio of gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate are applied to all well completions and well workovers, respectively, in the sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average gas production rate for each of these wells.

(vi) For equations W–12A and W–12B to this section, calculate new flowback rates for well completions and well workovers in each sub-basin and well type combination once every two years starting in the first calendar year of data collection.

(vii) For oil wells where the gas production rate is not metered and you elect to use equation W–10A to this section, calculate the average gas production rate ($PR_{s,p}$) using equation W–12C to this section. If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (g)(1)(vii)(A) or (B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

$$PR_{s,p} = GOR_p * \frac{V_p}{720} \qquad \text{(Eq. W-12C)}$$

Where:

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of well p, in the sub-basin and well type combination.

GOR_p = Average gas to oil ratio during the first 30 days of production after completions of newly drilled wells or workovers using hydraulic fracturing in standard cubic feet of gas per barrel of oil for each well p, that was measured in the sub-basin and well type combination; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in barrels of each well p, that was measured in the sub-basin and well type combination.

720 = Conversion from 30 days of production to hourly production rate.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in § 98.234(b).

(2) For paragraphs (g) introductory text and (g)(1) of this section, measurements and calculations are completed separately for workovers and completions per sub-basin and well type combination. A well type combination is a unique combination of the parameters listed in paragraphs (g)(2)(i) through (iv) of this section.

(i) Vertical or horizontal (directional drilling).

(ii) With flaring or without flaring.

(iii) Reduced emission completion/workover or not reduced emission completion/workover.

(iv) Oil well or gas well.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions from total natural gas volumetric emissions using calculations in paragraphs (u) and (v) of this section.

(h) *Gas well venting during completions and workovers without hydraulic fracturing*. Calculate annual volumetric natural gas emissions from each gas well venting during workovers without hydraulic fracturing using equation W–13A to this section. Calculate annual volumetric natural gas emissions from each gas well venting during completions without hydraulic fracturing using equation W–13B to this section. You must convert annual volumetric natural gas emissions to CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (h)(1) of this section. If emissions from gas well venting during completions and workovers without hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(h), as applicable.

$$E_{s,wo} = N_{wo} * EF_{wo} \quad \text{(Eq. W-13A)}$$

$$E_{s,p} = V_p \times T_p \quad \text{(Eq. W-13B)}$$

Where:

$E_{s,wo}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well workovers without hydraulic fracturing.

N_{wo} = Number of workovers per well that do not involve hydraulic fracturing in the reporting year.

EF_{wo} = Emission factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. Use 3,114 standard cubic feet natural gas per well workover without hydraulic fracturing.

$E_{s,p}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well completions without hydraulic fracturing.

V_p = Average daily gas production rate in standard cubic feet per hour for each well, p, undergoing completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the well produced to the flow-line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_p = Time that gas is vented directly to the atmosphere for each well, p, undergoing completion without hydraulic fracturing, in hours during the year.

(1) Calculate both CH_4 and CO_2 volumetric emissions from natural gas volumetric emissions using calculations in paragraph (u) of this section. Calculate both CH_4 and CO_2 mass emissions from volumetric emissions vented to atmosphere using calculations in paragraph (v) of this section.

(2) [Reserved]

(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. For industry segments other than natural gas distribution, 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. Natural gas distribution blowdowns with a unique physical volume of less than 500 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, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading. If emissions from blowdown vent stacks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(1) *Method for calculating unique physical volumes or distribution pipeline physical volumes.* You must calculate each unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves, in cubic feet, by using engineering estimates based on best available data. For natural gas distribution pipelines without isolation valves, calculate the unique physical volume of the distribution pipeline section that was isolated from operation by methods other than isolation valves, in cubic feet, by using engineering estimates based on best available data (e.g., diameter of the pipeline and length of isolated section).

(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) Calculate the total annual natural gas emissions from each unique physical volume that is blown down using either equation W–14A or W–14B to this section.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s Z_a} \right) - V * C \right) \quad \text{(Eq. W-14A)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Unique physical volume, in cubic feet, as calculated in paragraph (i)(1) of this section.

C = Purge factor is 1 if the unique physical volume is not purged, or 0 if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the temperature.

P_s = Absolute pressure at standard conditions (14.7 psia).P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the pressure.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

$$E_{s,n} = \sum_{p=1}^{N} \left[V_p \left(\frac{(459.67 + T_s)(P_{a,b,p} - P_{a,e,p})}{(459.67 + T_{a,p}) P_s Z_a} \right) \right] \quad \text{(Eq. W-14B)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

p = Individual occurrence of blowdown for the same unique physical volume.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V_p = Unique physical volume, in cubic feet, for each blowdown ‘‘p.’’

T_s = Temperature at standard conditions (60 °F).$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown ‘‘p’’. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the temperature.

P_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = 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 production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution 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 production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the pressure at the end of the blowdown.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(ii) Except as allowed in paragraph (i)(2)(iii) of this section, calculate annual CH_4 and CO_2 volumetric and mass emissions from each unique physical volume that is blown down by using the annual natural gas emission value as calculated in either equation W–14A or equation W–14B to this section and the calculation method specified in paragraph (i)(4) of this section. Calculate the total annual CH_4 and CO_2 emissions for each equipment or event type by summing the annual CH_4 and CO_2 mass emissions for all unique physical volumes associated with the equipment or event type.

(iii) For onshore natural gas transmission compression facilities and LNG import and export equipment, as an alternative to using the procedures in paragraph (i)(2)(ii) of this section, you may elect to sum the annual natural gas emissions as calculated using either equation W–14A or equation W–14B to this section for all unique physical volumes associated with the equipment type or event type. Calculate the total annual CH_4 and CO_2 volumetric and mass emissions for each equipment type or event type using the sums of the total annual natural gas emissions for each equipment type and the calculation method specified in paragraph (i)(4) of this section.

(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 petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, 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 and natural gas distribution industry segments, 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.

(3) *Method for determining emissions from blowdown vent stacks using a flow meter.* In lieu of determining emissions from blowdown vent stacks as specified in paragraph (i)(2) of this section, you may use a flow meter and measure blowdown vent stack emissions for any unique physical volumes determined according to paragraph (i)(1) of this section to be greater than or equal to 50 cubic feet. If you choose to use this method, you must measure the natural gas emissions from the blowdown(s) through the monitored stack(s) using a flow meter according to methods in § 98.234(b) and calculate annual CH_4 and CO_2 volumetric and mass emissions measured by the meters according to paragraph (i)(4) of this section.

(4) *Method for converting from natural gas emissions to GHG volumetric and mass emissions.* Calculate both CH_4 and CO_2 volumetric and mass emissions using the methods specified in paragraphs (u) and (v) of this section.

(j) *Hydrocarbon liquids and produced water storage tanks.* Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids and CH_4 emissions from atmospheric pressure storage tanks receiving produced water, from onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), and onshore natural gas processing facilities as specified in this paragraph (j). For wells, gas-liquid separators, or onshore petroleum and natural gas gathering and boosting or onshore natural gas processing 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, gas-liquid separators, or non-separator equipment with annual average daily throughput of hydrocarbon liquids greater than 0 barrels per day and less than 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 1, 2, or 3 as specified in paragraphs (j)(1) through (3) of this section. Annual average daily throughput of hydrocarbon liquids should be calculated using the flow out of the separator, well, or non-separator equipment determined over the actual days of operation. For atmospheric pressure storage tanks receiving produced water, calculate annual CH_4 emissions using Calculation Method 1, 2, or 3 as specified in paragraphs (j)(1) through (3) of this section. If you are required to use the flash emissions modeling software in paragraph (j)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual inventory reporting for the current reporting year, you must use Calculation Method 1 to calculate annual CH_4 and, if applicable, CO_2 emissions. For atmospheric pressure storage tanks routing emissions to a vapor recovery system or a flare, calculate annual emissions vented directly to atmosphere as specified in paragraph (j)(4) of this section. If you use Calculation Method 1 or Calculation Method 2 for gas-liquid separators sending hydrocarbon liquids to atmospheric pressure storage tanks, you must also calculate emissions that may have occurred due to hydrocarbon liquid dump valves not closing properly using the method specified in paragraph (j)(5) of this section. If emissions from atmospheric pressure storage tanks are 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).

(1) *Calculation Method 1.* For atmospheric pressure storage tanks receiving hydrocarbon liquids, calculate annual CH_4 and CO_2 emissions, and for atmospheric pressure tanks receiving produced water, calculate annual CH_4 emissions, using operating conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS®, Bryan Research & Engineering ProMax®, or, for atmospheric pressure storage tanks receiving hydrocarbon liquids from gas-liquid separator or non-separator equipment, 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 or produced water from the well, separator, or non-separator equipment enter an atmospheric pressure storage tank. If you elect to use ProMax®, you must use version 5.0 or above. A minimum of the parameters listed in paragraphs (j)(1)(i) through (vii) of this section, as applicable, must be used to characterize emissions. If paragraphs (j)(1)(i) through (vii) of this section indicate that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation and at least at the frequency specified. Determine all other applicable parameters in paragraphs (j)(1)(i) through (vii) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.,* if you calculate emissions using one simulation, use representative parameters for the operating conditions

over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year). If more than one simulation is performed, input parameters should be remeasured if no longer representative of operating conditions.

(i) Well, separator, or non-separator equipment temperature (must be measured at least annually if required as an input for the model).

(ii) Well, separator, or non-separator equipment pressure (must be measured at least annually if required as an input for the model).

(iii) [Reserved]

(iv) Sales or stabilized hydrocarbon liquids or produced water production rate (must be measured at least annually if required as an input for the model).

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Sales or stabilized hydrocarbon liquids API gravity, and well, separator, or non-separator equipment hydrocarbon liquids or produced water composition and Reid vapor pressure (must be measured if required as an input for the model). 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 specified in § 98.234(b) to sample and analyze sales or stabilized hydrocarbon liquids for API gravity, and hydrocarbon liquids or produced water composition and Reid vapor pressure. You must sample and analyze sales or stabilized oil for API gravity, and hydrocarbon liquids or produced water for composition and Reid vapor pressure within six months of equipment start-up or by January 1, 2030, whichever is later, and at least once every five years thereafter. Until such time that a sample is collected, determine API gravity by engineering estimate and process knowledge based on best available data, and determine composition and Reid vapor pressure by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section. For produced water, you may instead elect to use a representative sales oil or stabilized hydrocarbon liquid API gravity and a hydrocarbon liquid composition and Reid vapor pressure, and assume oil entrainment of 1 percent or greater.

(A) If separator or non-separator equipment hydrocarbon liquids 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 hydrocarbon liquids 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.* For atmospheric pressure storage tanks receiving hydrocarbon liquids, calculate annual CH_4 and CO_2 emissions and for atmospheric pressure tanks receiving produced water, calculate annual CH_4 emissions, using operating conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks and the methods in paragraph (j)(2)(i) of this section.

(i) Assume that all of the CH_4 and, if applicable, CO_2 in solution at well, separator, or non-separator equipment temperature and pressure is emitted from hydrocarbon liquids or produced water sent to atmospheric pressure 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 hydrocarbon liquids or produced water composition at well, separator, or non-separator pressure and temperature. You must sample and analyze hydrocarbon liquids or produced water composition within six months of equipment start-up or by January 1, 2030, whichever is later, and at least once every five years thereafter. Until such time that a sample is collected, determine produced water composition by engineering estimate and process knowledge based on best available data, and determine hydrocarbon liquids composition by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section. For produced water, you may instead elect to use a representative hydrocarbon liquid composition and assume oil entrainment of 1 percent or greater.

(ii) [Reserved]

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids as specified in paragraph (j)(3)(i) of this section. Calculate CH_4 emissions from atmospheric pressure storage tanks receiving produced water as specified in paragraph (j)(3)(ii) of this section.

(i) Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids using equation W–15A to this section:

$$E_{s,i} = EF_i \times Count \times 1{,}000 \qquad \text{(Eq. W-15A)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput greater than 0 barrels per day and less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed hydrocarbon liquids directly to the atmospheric pressure storage tank for which you elect to use this Calculation Method 3.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(ii) Calculate CH_4 emissions from atmospheric pressure storage tanks receiving produced water using equation W–15B to this section:

$$Mass_{CH_4} = EF_{CH_4} \times FR \times 0.001 \qquad \text{(Eq. W-15B)}$$

Where:

$Mass_{CH_4}$ = Annual total CH_4 emissions in metric tons.

EF_{CH_4} = Population emission factor for produced water in metric tons CH_4 per thousand barrels produced water per year. For produced water streams from separators, wells, or non-separator equipment with pressure less than or equal to 50 psi, use 0.0015. For produced water streams from separators, wells, or non-separator equipment with pressure greater than 50 but less than or equal to 250 psi, use 0.0142. For produced water streams from separators, wells, or non-separator equipment with pressure greater than 250 psi, use 0.0508. Pressure should be representative of separators, wells, or non-separator equipment that feed produced water directly to the atmospheric pressure storage tank.

FR = Annual flow rate of produced water to atmospheric pressure storage tanks, in barrels.

0.001 = Conversion from barrels to thousand barrels.

(4) *Emissions vented directly to atmosphere from atmospheric pressure storage tanks routed to vapor recovery systems or flares.* If the atmospheric pressure storage tank receiving your hydrocarbon liquids or produced water has a vapor recovery system or routes emissions to a flare, calculate annual emissions vented directly to atmosphere from the storage tank during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (j)(4)(i) of this section. Determine recovered mass as specified in paragraph (j)(4)(ii) of this section.

(i) For an atmospheric pressure storage tank that routes any emissions to a vapor recovery system or a flare, calculate vented emissions as specified in paragraphs (j)(4)(i)(A) through (E) of this section.

(A) Calculate vented emissions as specified in paragraph (j)(1), (2), or (3) of this section, which represents the emissions from the atmospheric storage tank prior to the vapor recovery system or flare. Calculate an average hourly vented emissions rate by dividing the vented emissions by the number of hours that the tank was in operation.

(B) To calculate vented emissions during periods when the tank was not routing emissions to a vapor recovery system or a flare, multiply the average hourly vented emissions rate determined in paragraph (j)(4)(i)(A) of this section by the number of hours that the tank vented directly to the atmosphere. Determine the number of hours that the tank vented directly to atmosphere by subtracting the hours that the tank was connected to a vapor recovery system or flare (based on engineering estimate and best available data) from the total operating hours for the tank in the calendar year. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(C) During periods when a thief hatch is open and emissions from the tank are routed to a vapor recovery system or a flare, assume the capture efficiency of the vapor recovery system or a flare is 0 percent. A thief hatch is open if it is fully or partially open such there is a visible gap between the hatch cover and the hatch portal. To calculate vented emissions during such periods, multiply the average hourly vented emissions rate determined in paragraph (j)(4)(i)(A) of this section by the number of hours that the thief hatch is open. Determine the number of hours that the thief hatch is open or not properly seated as specified in paragraph (j)(7) of this section.

(D) Calculate vented emissions not captured by the vapor recovery system or a flare due to causes other than open thief hatches based on best available data, including any data from operating pressure sensors on atmospheric pressure storage tanks.

(E) Calculate total emissions vented directly to atmosphere as the sum of the emissions calculated as specified in paragraphs (j)(4)(i)(B) through (D) of this section.

(ii) 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) when calculating mass recovered as specified in paragraphs (j)(4)(i)(C) and (D) of this section.

(5) *Gas-liquid separator dump valves.* 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 that did not close properly during the calendar year by using equation W–16 to this section. Determine the total time a dump valve did not close properly in the calendar year (Tdv) as specified in paragraph (j)(5)(i) 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 atmospheric pressure storage tanks that resulted from the dump valve on an associated gas-liquid separator that did not close properly.

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.

$E_{s,i}$ = Annual volumetric GHG emissions (either CO_2 or CH_4) as determined in paragraphs (j)(1) and (2) and, if applicable, (j)(4) of this section, in standard cubic feet per year, from atmospheric pressure storage tanks with dump valves on an associated gas-liquid separator that did not close properly.

8,760 = Conversion to hourly emissions.

T_{dv} = Total time a dump valve did not close properly in the calendar year as determined in paragraph (j)(5)(i) of this section, in hours.

(i) If a parametric monitor is operating on a controlled atmospheric pressure storage tank or gas-liquid separator, you must use data obtained from the parametric monitor to determine periods when the gas-liquid separator liquid dump valve is stuck in an open or partially open position. An applicable operating parametric monitor must be capable of logging data whenever a gas-liquid separator liquid dump valve is stuck in an open or partially open position, as well as when the gas-liquid separator liquid dump valve is subsequently closed. If an applicable parametric monitor is not operating, including during periods of time when the parametric monitor is malfunctioning, you must perform a visual inspection of each gas-liquid separator liquid dump valve to determine if the valve is stuck in an open or partially open position, in accordance with paragraph (j)(5)(i)(A) and (B) of this section.

(A) Audio, visual and olfactory inspections must be conducted at least once in a calendar year.

(B) If stuck gas-liquid separator liquid dump valve is identified, the dump valve must be counted as being open since the beginning of the calendar year, or from the previous audio, visual, and olfactory inspection that did not identify the dump valve as being stuck in the open position in the same calendar year. If the dump valve is fixed following visual inspection, the time period for which the dump valve was stuck open will end upon being repaired. If a stuck dump valve is identified and not repaired, the time period for which the dump valve was stuck open must be counted as having occurred through the rest of the calendar year.

(ii) [Reserved]

(6) *Mass emissions.* Calculate both CH_4 and CO_2 mass emissions from natural gas volumetric emissions using calculations in paragraph (v) of this section.

(7) *Thief hatches.* If a thief hatch sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the thief hatch sensor to determine periods when the thief hatch is open. An applicable operating thief hatch sensor must be capable of logging data whenever a thief hatch is open, as well as when the thief hatch is subsequently closed. If a thief hatch sensor is not operating but a tank pressure sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the pressure sensor to determine periods when the thief hatch is open. An applicable operating pressure sensor must be capable of logging tank pressure data. If neither an applicable thief hatch sensor nor an applicable pressure sensor is operating, including during periods of time when the sensors are malfunctioning, for longer than 30 days, you must perform a visual inspection of each thief hatch on a controlled atmospheric pressure storage tank in accordance with paragraph (j)(7)(i) through (iii) of this section.

(i) For thief hatches on controlled atmospheric pressure storage tanks subject to the standards in § 60.5395b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, visual inspections must be conducted at least as frequent as the required audio, visual, and olfactory inspections described in § 60.5416b or the applicable approved state plan or applicable Federal plan in part 62. If the time between required audio, visual, and olfactory inspections described in § 60.5416b or the applicable approved state plan or applicable Federal plan in part 62 is greater than one year, visual inspections must be conducted at least annually.

(ii) For thief hatches on controlled atmospheric pressure storage tanks not subject to the standards in § 60.5395b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, visual inspections must be conducted at least once in a calendar year.

(iii) If one visual inspection is conducted in the calendar year and an open thief hatch is found, assume the thief hatch was open for the entire calendar year or the entire period that the sensor(s) was not operating or malfunctioning. If multiple visual inspections are conducted in the calendar year, assume a thief hatch found open in the first visual inspection was open since the beginning of the year until the date of the visual inspection; assume a thief hatch found open in the last visual inspection of the year was open from the preceding visual inspection through the end of the year; assume a thief hatch found open in a visual inspection between the first and last visual inspections of the year was open since the preceding visual inspection until the date of the visual inspection.

(k) *Condensate storage tanks.* For vent stacks connected to one or more condensate storage tanks, either water or hydrocarbon, without vapor recovery, flares, or other controls, in onshore natural gas transmission compression or underground natural gas storage, calculate CH_4 and CO_2 annual emissions from compressor scrubber dump valve leakage as specified in paragraphs (k)(1) through (4) of this section. If emissions from compressor scrubber dump valve leakage are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(1) Except as specified in paragraph (k)(1)(iv) of this section, you must monitor the tank vapor vent stack annually for emissions using one of the methods specified in paragraphs (k)(1)(i) through (iii) of this section.

(i) Use an optical gas imaging instrument according to methods set forth in § 98.234(a)(1).

(ii) Measure the tank vent directly using a flow meter or high volume sampler according to methods in § 98.234(b) or (d) for a duration of 5 minutes.

(iii) Measure the tank vent using a calibrated bag according to methods in § 98.234(c) for a duration of 5 minutes or until the bag is full, whichever is shorter.

(iv) You may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the optical gas imaging instrument or acoustic leak detection device detects a leak, then you must use one of the methods in either paragraph (k)(2)(i) or (ii) of this section.

(i) Use a flow meter, such as a turbine meter, calibrated bag, or high volume sampler to estimate tank vapor volumes from the vent stack according to methods set forth in § 98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph (k)(1)(ii) or (iii) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(3) If a leaking dump valve is identified, the leak must be counted as having occurred since the beginning of the calendar year, or from the previous test that did not detect leaking in the same calendar year. If the leaking dump valve is fixed following leak detection, the leak duration will end upon being repaired. If a leaking dump valve is identified and not repaired, the leak must be counted as having occurred through the rest of the calendar year.

(4) Use the requirements specified in paragraphs (k)(4)(i) and (ii) of this section to quantify annual emissions.

(i) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(ii) Calculate CH_4 and CO_2 volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

(l) *Well testing venting and flaring.* Calculate CH_4 and CO_2 annual emissions from well testing venting as specified in paragraphs (l)(1) through (5) of this section. If emissions from well testing venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(l), as applicable.

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from oil well(s) tested. Determine the production rate from gas well(s) tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the procedures specified in paragraph (l)(2)(i) or (ii) of this section to determine GOR.

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) You may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using equation W–17A to this section (for oil wells) or equation W–17B to this section (for gas wells) for each well tested during the reporting year.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17A)}$$

$$E_{a,n} = PR * D \quad \text{(Eq. W-17B)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well testing for each well being tested in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil for each well being tested; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Average annual flow rate in barrels of oil per day for the oil well being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well being tested.

D = Number of days during the calendar year that the well is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from natural gas volumetric emissions using calculations in paragraphs (u) and (v) of this section.

(m) *Associated gas venting and flaring.* Calculate CH_4 and CO_2 annual emissions from associated gas venting not in conjunction with well testing (refer to paragraph (l) of this section) as specified in paragraphs (m)(1) through (3) of this section. If emissions from associated gas venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(m), as applicable.

(1) If you measure the gas flow to a vent using a continuous flow measurement device, you must use the measured flow volumes to calculate vented associated gas emissions.

(2) If you do not measure the gas flow to a vent using a continuous flow measurement device, you must follow the procedures in paragraphs (m)(2)(i) through (iii) of this section.

(i) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

(ii) If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (m)(2)(ii)(A) or (B) of this section to determine GOR.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in § 98.234(b).

(iii) Estimate venting emissions using equation W–18 to this section.

$$E_{s,n,p} = \left(GOR_p \times V_p\right) - SG_p \quad \text{(Eq. W-18)}$$

Where:

$E_{s,n,p}$ = Annual volumetric natural gas emissions at each well from associated gas venting at standard conditions, in cubic feet.

GOR_p = Gas to oil ratio, for well p, in standard cubic feet of gas per barrel of oil determined according to paragraphs (m)(2)(i) through (iii) of this section; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced, for well p, in barrels in the calendar year only during time periods in which associated gas was vented or flared.

SG_p = Volume of associated gas sent to sales and volume of associated gas used for other purposes at the facility site, including powering engines, separators, safety systems and/or combustion equipment and not flared or vented, for well p, in standard cubic feet of gas in the calendar year only during time periods in which associated gas was vented or flared.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraph (u) and (v) of this section.

(n) *Flare stack emissions.* Except as specified in paragraph (n)(9) of this section, calculate CO_2, CH_4, and N_2O emissions from each flare stack as specified in paragraphs (n)(1) through (8) of this section. For each flare, disaggregate the total flared emissions to applicable source types as specified in paragraph (n)(10) of this section.

(1) *Destruction efficiency and combustion efficiency.* To calculate CH_4 emissions for flares, use the applicable default destruction and combustion efficiencies specified in paragraphs (n)(1)(i) through (iii) of this section or alternative destruction and combustion efficiencies determined in accordance with paragraph (n)(1)(v) of this section. If you change the method with which you determine the default destruction and combustion efficiencies during a year, then use the applicable destruction and combustion efficiencies in paragraphs (n)(1)(i) through (iii) and paragraph (n)(1)(v) of this section for each portion of the year during which a different default destruction and combustion efficiency was used, and calculate an annual time-weighted average destruction and combustion efficiency to report for the flare.

(i) *Tier 1.* Use a default destruction efficiency of 98 percent and a default combustion efficiency of 96.5 percent if you follow the performance test requirements specified in paragraph (n)(1)(i)(A) of this section and the operating limit requirements specified in paragraph (n)(1)(i)(B) of this section, or the operating limit requirements specified in paragraph (n)(1)(i)(C) of this section, as applicable. You must also keep the applicable records in § 63.655(i)(2), (3), and (9) of this chapter. If you fail to fully conform with all cited provisions for a period of 15 consecutive days, you must utilize the Tier 3 default destruction and combustion efficiency values until such time that full conformance is achieved. You must document these periods and maintain records as specified in § 98.237 of the date when the non-conformance began, and the date when full conformance is re-established.

(A) The applicable testing requirements in § 63.645(a), (b), (c), (d), and (i) of this chapter, including § 63.116 (a)(2), (3), (b), and (c) of this chapter. When § 63.645 refers to ''organic HAP,'' the terms ''methane'' and ''CO_2'' shall apply for the purposes of this subpart.

(B) The applicable monitoring requirements in § 63.644(a), (b), (d), and (e) of this chapter. The data to submit in a Notification of Compliance Status report in § 63.644(d) of this chapter shall be maintained as records for the purposes of this section (n)(1)(i), and references to violations in § 63.644(e) of this chapter do not apply for the purposes of this section (n)(1)(i).

(C) The requirements in § 63.670 (a) through (n), § 63.670(p), and § 63.671 of this chapter.

(ii) *Tier 2.* Use a default destruction efficiency of 95 percent and a default combustion efficiency of 93.5 percent if you follow the requirements specified in either paragraph (n)(1)(ii)(A), (B), (C), or (D) of this section. If you fail to fully conform with all cited provisions for a period of 15 consecutive days, you must utilize the Tier 3 default destruction and combustion efficiency values until such time that full conformance is achieved. You must document these periods and maintain records as specified in § 98.237 of the date when the non-conformance began, and the date when full conformance is re-established.

(A) The requirements in § 60.5412b(a)(1) of this chapter, along with the applicable testing requirements in § 60.5413b of this chapter, the applicable continuous compliance requirements in § 60.5415b(f) of this chapter, and the applicable continuous monitoring requirements in § 60.5417b of this chapter. You must also keep the applicable records in § 60.5420b(c)(11) of this chapter.

(B) The requirements in § 60.5412b(a)(3) of this chapter, the applicable continuous compliance requirements in § 60.5415b(f) of this chapter, and the applicable continuous monitoring requirements in § 60.5417b(b) of this chapter. You must also keep the applicable records in § 60.5420b(c)(11) of this chapter.

(C) If using an enclosed combustion device tested by the manufacturer in accordance with § 60.5413b(d) of this chapter, the requirements in § 60.5413b(b)(5)(iii) and (e) of this chapter, the applicable continuous compliance requirements in § 60.5415b(f) of this chapter, and the applicable continuous monitoring requirements in § 60.5417b of this chapter. You must also keep the applicable records in § 60.5420b(c)(11) of this chapter.

(D) If you are subject to an approved state plan or applicable Federal plan in part 62 of this chapter that requires the reduction of methane by 95 percent, you may follow all applicable requirements of the approved state plan or applicable Federal plan in part 62 of this chapter, including the testing, continuous compliance, continuous monitoring, and recordkeeping requirements.

(iii) *Tier 3.* Use a default destruction efficiency of 92 percent and a default combustion efficiency of 90.5 percent if you do not meet the requirements specified in either paragraph (n)(1)(i) or (ii) of this section.

(iv) *Alternative test method.* If you are utilizing the tier 2 default efficiencies in paragraph (n)(2)(ii) of this section and are not subject to 40 CFR subpart OOOOb or an applicable approved state or applicable federal plan under part 62 of this chapter that requires 95 percent reduction in methane emissions, you may conduct a performance test using EPA OTM–52 (incorporated by reference, see § 98.7) as an alternative to conducting a performance test using the methods specified in § 60.5413b of this chapter, or in an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If the combustion efficiency obtained using OTM–52 is equal to or greater than 93.5 percent, then use a default destruction efficiency of 95 percent and a default combustion efficiency of 93.5 percent. If you utilize OTM–52 for the testing, you must comply with all the applicable monitoring, compliance, and recordkeeping requirements identified in paragraph (n)(1)(ii) of this section.

(v) *Alternative destruction and combustion efficiencies.* You may use a directly measured combustion efficiency instead of the default combustion efficiencies specified in paragraphs (n)(1)(i) through (iii) of this section if you follow the provisions of paragraph (n)(1)(v)(A) through (E) of this section.

(A) Measure the combustion efficiency in accordance with an alternative test method approved in accordance with § 60.5412b(d) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(B) Conduct monitoring as specified in §§ 60.5415b(f)(1)(x) and (xi) and 60.5417b(i) of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(C) Adhere to all conditions in the monitoring plan you prepare as specified in § 60.5417b(i)(2) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter at all times.

(D) You must use a destruction efficiency equal to the combustion efficiency plus 1.5.

(E) If you fail to fully conform with your plan for a period of 15 or more consecutive days, you must utilize the Tier 3 default destruction and combustion efficiency values until such time that full conformance is achieved. You must document these periods and maintain records as specified in § 98.237 of the date when the non-conformance began, and the date when full conformance is re-established.

(2) *Pilot.* Continuously monitor for the presence of a pilot flame or combustion flame as specified in paragraph (n)(2)(i) of this section or visually inspect for the presence of a pilot flame or combustion flame as specified in paragraph (n)(2)(ii) of this section, as applicable.. If you comply with tier 2, you must also use data collected according to paragraph (n)(2)(iii) of this section in your calculations of time the flare was unlit and the fraction of gas routed to the flare during periods when the flare was unlit. If you continuously monitor, then periods when the flare is unlit must be determined based on those data, except when contradicted by data collected according to paragraph (n)(2)(iii) of this section. Determine the fraction of the total volume that is routed to the flare during unlit periods as specified in paragraph (n)(2)(iv) of this section.

(i) At least once every five minutes monitor for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, infrared sensor, video surveillance system, or advanced remote monitoring method) capable of detecting that the pilot or combustion flame is present at all times.

(A) Monitoring for the presence of a flare flame in accordance with

§ 60.5417b satisfies the requirement of this paragraph (n)(2).

(B) You may use multiple or redundant monitoring devices. When a discrepancy occurs between multiple devices, you must either visually confirm or use video surveillance output to confirm that the flame is present as soon as practicable after detecting the discrepancy to ensure that at least one device is operating properly. If you confirm that at least one device is operating properly, you may rely on the properly operating device(s) to monitor the flame.

(C) Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this part 98.

(D) Track the length of time over all periods when the flare is unlit and calculate the fraction of the total flow to the flare that was routed to the flare when the flare was unlit as specified in paragraph (n)(2)(iv) of this section.

(E) If all continuous monitoring devices are out of service for more than one week, then visually inspect for the presence of a pilot flame or combustion flame at least once per week for the first 4 weeks that the monitoring devices are out of service or until at least one repaired or new device is operational, whichever period is shorter. If all continuous monitoring devices are out of service for less than one week, then at least one visual inspection must be conducted during the outage. If a flame is not detected during a weekly visual inspection, assume the pilot has been unlit since the previous inspection or the last time the continuous monitoring device detected a flame, and assume that the pilot remains unlit until a subsequent inspection or continuous monitoring device detects a flame. If the monitoring device outage lasts more than 4 weeks, then you may switch to conducting inspections at least once per month in accordance with paragraph (n)(2)(ii) of this section.

(ii) As an alternative to continuous monitoring as specified in paragraph (n)(2)(i) of this section, if you comply with tier 3 in paragraph (n)(1)(iii) of this section, at least once per month visually inspect for the presence of a pilot flame or combustion flame. You may also conduct visual inspections when using an alternative test method in accordance with paragraph (n)(1)(iv) of this section that allows visual inspections. If a flame is not detected, track the time since the previous inspection until a subsequent inspection detects a flame, and use this time in your calculation of the fraction of the total flow to the flare that was routed to the flare when the flare was unlit as specified in paragraph (n)(2)(iv) of this section. Use the sum of the measured flows, as determined from measurements obtained under paragraph (n)(1) of this section, during all time periods when the pilot was determined to be unlit, to calculate the fraction of the total annual volume that is routed to the flare when it is unlit.

(iii) For a flare subject to 40 CFR part 60 subpart OOOOb, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, a flare inspection conducted using an OGI camera during a fugitive emissions survey in accordance with § 60.5415b(f)(1)(x) constitutes a pilot flame inspection under this subpart. If a flame is not detected, track the time from the previous inspection until a subsequent inspection or continuous monitoring device detects a flame and use this time in your calculation of the fraction of the total flow to the flare that was routed to the flare when the flare was unlit as specified in paragraph (n)(2)(iv) of this section.

(iv) If you measure total flow to the flare in accordance with paragraph (n)(3)(i) of this section, calculate the fraction of the total annual volume that is routed to the flare when it is unlit using the actual flow during the unlit time periods that are tracked according to paragraph (n)(2)(i)(D), (ii), or (iii) of this section. If you determine flows of individual streams routed to the flare in accordance with paragraph (n)(3)(ii) of this section, use the stream-specific average flow rates for the streams routed to the flare during unlit times to calculate the fraction of the total annual volume that is routed to the flare when it is unlit.

(3) *Flow determination.* Calculate total flow to the flare as specified in paragraph (n)(3)(i) of this section or determine flow of each individual stream that is routed to the flare as specified in paragraph (n)(3)(ii) of this section. Use engineering calculations based on best available data and company records to calculate pilot gas flow to add to the total gas flow to the flare.

(i) Use a continuous parameter monitoring system to measure flow of gas to the flare downstream of any sweep, purge, or auxiliary gas addition. You may use either flow meters or indirectly calculate flow using other parameter monitoring systems combined with engineering calculations, such as line pressure, line size, and burner nozzle dimensions. If you use a continuous parameter monitoring system, you must use the measured flow in calculating the total flow volume to the flare. The continuous parameter monitoring system must measure data values at least once every hour.

(ii) Determine flow to the flare from individual sources, including sweep, purge, auxiliary fuel, and collective flow from offsite sources that route gas to the flare using any combination of the methods in paragraphs (n)(3)(ii)(A) and (B) of this section, as applicable. Adjust the volumes determined as specified in paragraphs (n)(3)(ii)(A) and (B) of this section by any estimated bypass volumes diverted from entering the flare and leaks from the closed vent system in accordance with paragraphs (n)(3)(ii)(C) and (D) of this section. Do not adjust the volumes routed to the flare for volumes diverted through bypass lines located upstream of the flow measurement or determination location.

(A) Use a continuous flow meter to measure the flow of gas from individual sources (or combination of sources) that route gas to the flare. If the emission streams for multiple sources are routed to a manifold before being combined with other emission streams, you may conduct the measurement in the manifold instead of from each source that is routed to the manifold. If you use a continuous flow meter, you must use the measured flow in calculating the total flow volume to the flare. The continuous flow meter must measure data values at least once every hour.

(B) If flow from a source is not measured using a continuous flow meter, then use methods specified in paragraphs (n)(3)(ii)(B)(1) through (*8*) of this section, as applicable.

(*1*) Determine flow of emission streams routed to flares from acid gas removal units using Calculation Method 3 or Calculation Method 4 as specified in paragraph (d)(3) or (4) of this section. Use the method specified in paragraph (n)(3)(ii)(B)(*8*) of this section to determine the volume of non-GHG constituents in a stream from an acid gas removal unit or nitrogen removal unit and add to the volume of GHGs to determine the total volume to the flare.

(*2*) Determine flow of emission streams routed to flares from dehydrators using an applicable method specified in paragraph (e) of this section. When using Calculation Method 2 to determine volume of GHGs from small glycol dehydrators, also use the method specified in paragraph (n)(3)(ii)(B)(*8*) of this section to determine the volume of non-GHG constituents in the stream to the flare and add to the volume of GHGs to determine the total volume to the flare.

(*3*) Determine flow of emission streams routed to flares from completions and workovers with hydraulic fracturing using a method specified in paragraph (g) of this section.

(*4*) Determine flow of emission streams routed to flares from completions and workovers without hydraulic fracturing using a method specified in paragraph (h) of this section.

(*5*) Determine flow of emission streams routed to flares from hydrocarbon liquids and produced water storage tanks using a method specified in paragraph (j) of this section. When using Calculation Method 2 or Calculation Method 3 to calculate the volume of GHGs, use the method specified in paragraph (n)(3)(ii)(B)(*8*) of this section to determine the volume of non-GHG constituents in the stream to the flare and add to the volume of GHGs to determine the total volume to the flare.

(*6*) Determine flow of emission streams routed to flares from well testing using an applicable method specified in paragraph (l) of this section.

(*7*) Determine flow of associated gas emission streams routed to flares using the method specified in paragraph (m)(2) of this section.

(*8*) Use engineering calculations based on process knowledge, company records, and best available data to calculate flow for sources other than those described in paragraphs (n)(3)(ii)(B)(1) through (7) of this section and to calculate volume of non-GHG constituents in streams for which the method used in paragraphs (n)(3)(ii)(B)(*1*), (*2*), and (5) of this section calculates only the GHG flow.

(C) If the closed vent system that routes emissions to the flare contains one or more bypass devices that could be used to divert all or a portion of the gases from entering the flare, then you must determine when flow is diverted through the bypass and estimate the volume that bypasses the flare. The bypass volume may be determined based on engineering calculations, process knowledge, and best available data. Use the estimated bypass volume to adjust the volumes determined in accordance with paragraph (n)(3)(ii)(A) or (B) of this section to determine the flow to the flare. For bypass volumes that are diverted directly to atmosphere, use the estimated volume in the calculation and reporting of vented emissions from the applicable source(s).

(D) If you determine a component in the closed vent system is leaking, you must adjust the flow determined in accordance with paragraph (n)(3)(ii)(A) or (B) of this section by the estimated volume of the leak to determine the flow to the flare. Estimate the leak volume based on engineering calculations, process knowledge, and best available data. Report the estimated leak volume as vented emissions from the applicable source(s).

(4) *Gas composition.* Determine the composition of the inlet gas to the flare as specified in either paragraph (n)(4)(i) or (ii) of this section, or determine composition of the individual streams that are combined and routed to the flare as specified in paragraph (n)(4)(iii) of this section. Use representative compositions of pilot gas determined by engineering calculation based on process knowledge and best available data.

(i) Use a continuous gas composition analyzer on the inlet gas to the flare burner downstream of any purge, sweep, or auxiliary fuel addition to measure annual average mole fractions of methane, ethane, propane, butane, pentanes plus, and CO_2. If you use a continuous gas composition analyzer on the total inlet stream to the flare, you must use the measured annual average mole fractions to calculate total emissions from the flare. The continuous gas composition analyzer must measure data values at least once every hour.

(ii) Take samples of the inlet gas to the flare burner downstream of any purge, sweep, or auxiliary fuel addition at least annually in which gas is routed to the flare and analyze for methane, ethane, propane, butane, pentanes plus, and CO_2 constituents. Determine the annual average concentration of each constituent as the annual average of all valid measurements for that constituent during the year and you must use those data to calculate flared emissions.

(iii) When composition is not determined at the inlet to the flare as specified in either paragraph (i) or (ii) of this section, then determine annual average compositions for streams from individual sources (or combinations of sources), including sweep, purge, and auxiliary fuel, routed to the flare using any combination of the methods specified in paragraphs (n)(4)(iii)(A) and (B) of this section, as applicable.

(A) Use a continuous gas composition analyzer to measure annual average mole fractions of methane, ethane, propane, butane, pentanes plus, and CO_2 constituents. If emission streams for multiple sources are routed to a manifold before being combined with other emission streams, you may measure gas composition in the manifold instead of from each source that is routed to the manifold. If you use a continuous gas composition analyzer, you must use the measured annual average mole fractions to calculate flared emissions for the stream. The continuous gas composition analyzer must measure data values at least once every hour.

(B) If composition is not measured in accordance with paragraph (n)(4)(iii)(A) of this section, then use methods specified in paragraphs (n)(4)(iii)(B)(*1*) through (*7*) of this section to determine composition, as applicable. When paragraphs (n)(4)(iii)(B)(*1*) through (*5*) reference continuous gas composition analyzer requirements in paragraph (u)(2) of this section, the requirements in paragraph (n)(4)(iii)(A) apply for the purposes of this paragraph (n)(4)(iii)(B). When paragraphs (n)(4)(iii)(B)(*1*) through (*5*) reference paragraph (u)(2) of this section, the language ''your most recent available analysis'' in paragraph (u)(2)(i) of this section means ''annual samples'' for the purposes of this paragraph (n)(4)(iii)(B).

(*1*) Determine the total annual average GHG composition of streams from acid gas removal units based on either process simulation as specified in paragraph (d)(4) of this section or quarterly sampling in accordance with paragraphs (d)(6) and (10) of this section, and determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(5) of this section.

(*2*) Determine the total annual average composition of streams from glycol dehydrators using Calculation Method 1 as specified in paragraph (e)(1) of this section or determine the annual average GHG composition as specified in paragraph (u)(2) of this section for the applicable industry segment. Determine annual average GHG composition of streams from desiccant dehydrators as specified in paragraph (u)(2) of this section. If you determine GHG composition in accordance with paragraph (u)(2) of this section, also determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(*5*) of this section.

(*3*) Determine the total annual average composition of streams from hydrocarbon liquids and produced water storage tanks using Calculation Method 1 in accordance with paragraph (j)(1) of this section or determine the annual average GHG composition as specified in paragraph (u)(2)(i) of this section. If you determine annual average GHG composition as specified in paragraph (u)(2)(i) of this section, then also determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(*5*) of this section.

(*4*) For onshore natural gas processing facilities, determine GHG mole fractions for all emission sources downstream of the de-methanizer overhead or dew point control based on samples of facility-specific residue gas to transmission pipeline systems taken at least once per year according to methods set forth in § 98.234(b), and determine GHG mole fractions for all emission sources upstream of the de-methanizer or dew point control based on samples of feed natural gas taken at least once per year according to methods set forth in § 98.234(b). For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole fraction in feed natural gas liquid streams as determined from samples taken at least once per year. If multiple samples of a stream are taken in a year, use the arithmetic average GHG composition.

(*5*) Except as specified in paragraph (n)(4)(iii)(B)(*6*) of this section, for streams from any source type other than those identified in paragraphs (n)(4)(iii)(B)(*1*) through (*4*) of this section, and for purge gas, sweep gas, and auxiliary fuel, determine the annual average GHG composition as specified in paragraph (u)(2) of this section for the applicable industry segment, and determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(*7*) of this section.

(*6*) When the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentanes-plus, or mixed light hydrocarbons, you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(*7*) When only the GHG composition is determined in accordance with paragraph (u)(2) of this section, determine the annual average composition of ethane, propane, butane, and pentanes plus in the stream using a representative composition based on process knowledge and best available data.

(5) *Calculate CH_4 and CO_2 emissions.* Calculate GHG volumetric emissions from flaring at standard conditions using equations W–19 and W–20 to this section and as specified in paragraphs (n)(5)(i) through (iv) of this section.

$$E_{s,CH_4} = V_s \times X_{CH_4} \times \left[\left(1 - \eta_D\right) \times Z_L + Z_U\right] \qquad \text{(Eq. W-19)}$$

$$E_{s,CO_2} = V_s \times X_{CO_2} + \sum_{j=1}^{5}\left(\eta_C \times V_s \times Y_j \times R_j \times Z_L\right) \qquad \text{(Eq. W-20)}$$

Where:

E_{s,CH_4} = Annual CH_4 emissions from flare stack in cubic feet, at standard conditions.

E_{s,CO_2} = Annual CO_2 emissions from flare stack in cubic feet, at standard conditions.

V_s = Volume of gas sent to flare in standard cubic feet, during the year as determined in paragraph (n)(3) of this section.

ηD = Flare destruction efficiency, expressed as fraction of hydrocarbon compounds in gas that is destroyed by a burning flare, but may or may not be completely oxidized to CO_2.

ηC = Flare combustion efficiency, expressed as fraction of hydrocarbon compounds in gas that is oxidized to CO_2 by a burning flare.

X_{CH_4} = Annual average mole fraction of CH_4 in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(4) of this section.

X_{CO_2} = Annual average mole fraction of CO_2 in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(4) of this section.

ZU = Fraction of the feed gas sent to an un-lit flare determined from both the total time the flare was unlit as determined by monitoring the pilot flame or combustion flame as specified in paragraph (n)(2) of this section and the volume of gas routed to the flare during periods when the flare was unlit based on the flow determined in accordance with paragraph (n)(3) of this section.

Z_L = Fraction of the feed gas sent to a burning flare (equal to 1—ZU).

Y_j = Annual average mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(4) of this section.

R_j = Number of carbon atoms in the hydrocarbon constituent j in the feed gas to the flare: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(i) If you measure the gas flow at the flare inlet as specified in paragraph (n)(3)(i) of this section and you measure gas composition for the inlet gas to the flare as specified in paragraph (n)(4)(i) or (ii) of this section, then use those data in equations W–19 and W–20 to this section to calculate total emissions from the flare.

(ii) If you determine the flow from each source as specified in paragraph (n)(3)(ii) of this section and you measure gas composition for the inlet gas to the flare as specified in paragraph (n)(4)(i) or (ii) of this section, then sum the flows for each stream to calculate the total annual gas flow to the flare. Use that total annual flow with the annual average concentration of each constituent as calculated in paragraph (n)(4)(i) or (ii) of this section in equations W–19 and W–20 to this section to calculate total emissions from the flare.

(iii) If you determine the flow from each source as specified in paragraph (n)(3)(ii) of this section and you determine gas composition for the emission stream from each source as specified in paragraph (n)(4)(iii) of this section, then calculate total emissions from the flare as specified in either paragraph (n)(5)(iii)(A) or (B) of this section.

(A) Use each set of stream-specific flow and annual average concentration data in equations W–19 and W–20 to this section to calculate stream-specific flared emissions for each stream, and then sum the results from each stream-specific calculation to calculate the total emissions from the flare.

(B) Sum the flows from each source to calculate the total gas flow into the flare and use the source-specific flows and source-specific annual average concentrations to determine flow-weighted annual average concentrations of CO_2 and hydrocarbon constituents in the combined gas stream into the flare. Use the calculated total gas flow and the calculated flow-weighted annual average concentrations for the inlet gas stream to the flare in equations W–19 and W–20 to this section to calculate the total emissions from the flare.

(iv) You may not combine measurement of the inlet gas flow to the flare as specified in paragraph (n)(3)(i) of this section with measurement of the gas composition of the streams from each source as specified in paragraph (n)(4)(iii) of this section.

(6) *Convert volume at actual conditions to volume at standard conditions.* Convert GHG volumetric emissions to standard conditions using calculations in paragraph (t) of this section.

(7) *Convert volumetric emissions to mass emissions.* Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculation in paragraph (v) of this section.

(8) *Calculate N_2O emissions.* Calculate N_2O emissions from flare stacks using equation W–40 to this section. Determine the values of parameters ''HHV'' and ''Fuel'' in equation W–40 to this section as specified in paragraphs (n)(8)(i) through (iv) of this section, as applicable.

(i) Directly measure the annual average higher heating value in the inlet stream to the flare using either a continuous gas composition analyzer or a calorimeter. Use this flare-specific annual average higher heating value for the parameter ''HHV'' in equation W–40 to this section, and use either the total inlet flow to the flare measured as specified in paragraph (n)(3)(i) of this section or the sum of the flows of individual streams routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter ''Fuel'' in equation W–40 to this section to calculate the total N_2O emissions from the flare.

(ii) Calculate the annual average higher heating value in the inlet stream to the flare using annual average gas compositions of the inlet stream measured in accordance with paragraph (n)(4)(i) or (ii) of this section. Use this flare-specific annual average higher heating value for the parameter ''HHV'' in equation W–40 to this section, and use either the total inlet flow to the flare measured as specified in paragraph (n)(3)(i) of this section or the sum of the flows of individual streams routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter ''Fuel'' in equation W–40 to this section to calculate the total N_2O emissions from the flare.

(iii) Directly measure the annual average higher heating values in the individual streams routed to the flare using either a continuous gas composition analyzer or a calorimeter. Calculate the total N_2O emissions from the flare as specified in either paragraph (n)(8)(iii)(A) or (B) of this section.

(A) Use the stream-specific annual average higher heating values for the parameter ''HHV'' in equation W–40 to this section, use the stream-specific flows as determined in paragraph (n)(3)(ii) of this section for the parameter ''Fuel'' in equation W–40 to this section in separate stream-specific calculations of N_2O emissions using equation W–40 to this section, and sum the resulting values to calculate the total N_2O emissions from the flare.

(B) Use the stream-specific annual average higher heating values and flows to calculate a flow-weighted annual average higher heating value to use as the parameter ''HHV'' in equation W–40 to this section and the sum of the individual stream flows routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter ''Fuel'' in equation W–40 to this section to calculate total N_2O emissions from the flare.

(iv) Calculate annual average higher heating values for the individual streams routed to the flare using gas compositions determined in accordance with paragraph (n)(4)(iii) of this section. Calculate the total N_2O emissions from the flare as specified in either paragraph (n)(8)(iv)(A) or (B) of this section.

(A) Use the stream-specific annual average higher heating values and the stream-specific flows in separate stream-specific calculations of N_2O emissions using equation W–40 to this section and sum the resulting values to calculate the total N_2O emissions from the flare.

(B) Use the stream-specific annual average higher heating values and flows to calculate a flow-weighted annual average higher heating value to use as the parameter ''HHV'' in equation W–40 to this section and the sum of the individual stream flows routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter ''Fuel'' in equation W–40 to this section to calculate total N_2O emissions from the flare.

(9) *CEMS.* If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor for the combustion gases from the flare, you must calculate CO_2 emissions for the flare using the CEMS. You must follow the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack CO_2 emissions, you must also comply with all other requirements specified in paragraphs (n)(1) through (8) of this section, except that calculation of CO_2 emissions using equation W–20 to this section is not required.

(10) *Disaggregation.* Disaggregate the total emissions from the flare as calculated in paragraphs (n)(7) and (8) of this section or paragraph (n)(9) of this section, as applicable, to each source type listed in paragraphs (n)(10)(i) through (viii) of this section, as applicable to the industry segment, that routed emissions to the flare. If emissions from the flare are calculated in accordance with paragraph (n)(5)(iii) of this section using stream-specific flow and composition, including combined streams that contain emissions from only a single source type, use the source-specific emissions calculated using these data to calculate the disaggregated emissions per source type. If the total emissions from the flare are calculated using total flow and/or total annual average composition of the total inlet stream to the flare, or if flow or composition are determined for a combined stream that contains emissions from more than one source type, then use engineering calculations and best available data to disaggregate the total emissions to the applicable source types.

(i) Acid gas removal units.

(ii) Dehydrators.

(iii) Completions and workovers with hydraulic fracturing.

(iv) Completions and workovers without hydraulic fracturing.

(v) Hydrocarbon liquids and produced water storage tanks.

(vi) Well testing.

(vii) Associated gas.

(viii) Other (collectively).

(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) of this section and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n). If emissions from a compressor source are routed to combustion, paragraphs (o)(1) through (11) of this section 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 a vapor recovery system, paragraphs (o)(1) through (11) of this section do not apply.

(1) General requirements for conducting volumetric emission measurements. You must conduct volumetric emission measurements on each centrifugal compressor as specified in this paragraph. Compressor sources (as defined in § 98.238) without manifolded vents must use a measurement method specified in paragraph (o)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in § 98.238) must use a measurement method specified in paragraph (o)(1)(i), (ii), (iii), or (iv) of this section.

(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.

(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 (o)(6)(ii) of this section.

(ii) *Centrifugal compressor source continuous monitoring.* Instead of measuring the compressor source according to paragraph (o)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (o)(3) of this section.

(iii) *Manifolded centrifugal compressor source as found measurements.* For a compressor source that is part of a manifolded group of compressor sources (as defined in § 98.238), instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (o)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (o)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) *Manifolded centrifugal compressor source continuous monitoring.* For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressor sources as specified in paragraph (o)(5) of this section.

(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.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer according to methods set forth in § 98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(D) You may choose to use any of the methods set forth in § 98.234(a) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a), then you must use one of the methods specified in paragraph (o)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a), 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.

(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)(iii)(A) through (D) of this section. The measurement should be conducted on the compressor side dry seal. 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.

(3) *Methods for continuous measurement from individual centrifugal compressor sources.* If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (o)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (o)(3)(i) and (ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor source at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) *Methods for performing as found measurements from manifolded groups of centrifugal compressor sources.* If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (o)(4)(i) and (ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) A temporary meter such as a vane anemometer according the methods set forth in § 98.234(b).

(B) Calibrated bagging according to methods set forth in § 98.234(c).

(C) A high volume sampler according to methods set forth § 98.234(d).

(D) [Reserved]

(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.

(F) If one of the screening methods specified in § 98.234(a)(1) through (3) identifies a leak in a manifolded group of centrifugal compressor sources, you may use acoustic leak detection, according to § 98.234(a)(5), to identify the source of the leak. You must use one of the methods specified in paragraphs (o)(4)(ii)(A) through (D) of this section to quantify emissions from the identified source.

(5) *Methods for continuous measurement from manifolded groups of centrifugal compressor sources.* If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (o)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) *Method for calculating volumetric GHG emissions from as found measurements for individual centrifugal compressor sources.* For compressor sources measured according to paragraph (o)(1)(i) of this section, you must calculate annual GHG emissions from the compressor sources as specified in paragraphs (o)(6)(i) through (iv) of this section.

(i) Using equation W–21 to 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.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-21)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (o)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination for which Es,i,m is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

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 to 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.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-22)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (o)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which Es,i,m is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

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 to 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 to this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

$EF_{s,m}$ = Reporter emission factor to be used in equation W–22 to this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in equation W–21 to this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A), (B), or (C) of this section.

(iv) The reporter emission factor in equation W–23 to this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) *Method for calculating volumetric GHG emissions from continuous monitoring of individual centrifugal compressor sources.* For compressor sources measured according to paragraph (o)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using equation W–24A to this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \quad \text{(Eq. W-24A)}$$

Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) *Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of centrifugal compressor sources.* For manifolded groups of compressor sources measured according to paragraph (o)(1)(iii) of this section, you must calculate annual volumetric GHG emissions using equation W–24B to this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(8) or paragraph (p)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \quad \text{(Eq. W-24B)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet. T_g = 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. $MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (o)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) *Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of centrifugal compressor sources.* For a manifolded group of compressor sources measured according to paragraph (o)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using equation W–24C to this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(9) or paragraph (p)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \qquad \text{(Eq. W-24C)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(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 volumetric emissions from centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (o)(10)(i) through (iv), as applicable.

(i) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals, you must conduct the volumetric emission measurements as required by § 60.5380b(a)(5) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, conduct all additional volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (o)(6) through (9) of this section. Conduct all measurements required by this paragraph (o)(10)(i) at the frequency specified by § 60.5380b(a)(4) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5380b(a)(4) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (o)(6)(ii) of this section.

(ii) For all centrifugal compressors 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 the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals, you may elect to conduct the volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (o)(6) through (9) of this section.

(iii) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (o)(10)(i) of this section does not apply and you do not elect to conduct the volumetric measurements specified in paragraph (o)(1) of this section, you must calculate total atmospheric wet seal oil degassing vent emissions from all centrifugal compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using equation W–25A to this section. Emissions from centrifugal compressor wet seal oil degassing vents that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (o).

$$E_{s,i} = \sum_{p=1}^{Count} E_{s,i,p} \qquad \text{(Eq. W-25A)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from all centrifugal compressors, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors with wet seal oil degassing vents that are vented directly to the atmosphere.

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for centrifugal compressor p, at standard conditions, in cubic feet, calculated using equation W–25B to this section.

(iv) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (o)(10)(i) of this section does not apply, and you do not elect to conduct the volumetric measurements specified in paragraph (o)(1) of this section, you must calculate wet seal oil degassing vent emissions from each centrifugal compressor using equation W–25B to this section. Emissions from centrifugal compressor wet seal oil degassing vents that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (o).

$$E_{s,i,p} = EF_{s,p} \times \frac{T_p}{T_{total}} \times \frac{GHG_{i,p}}{GHG_{EF}} \quad \text{(Eq. W-25B)}$$

Where:

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for centrifugal compressor p, at standard conditions, in cubic feet.

$EF_{s,p}$ = Emission factor for centrifugal compressor p, in standard cubic feet per year. Use 1.2 × 107 standard cubic feet per year per compressor for CH_4 and 5.30 × 105 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

T_p = Total time centrifugal compressor p was in operating mode, for which Es,i,p is being calculated in the reporting year, in hours.

T_{total} = Total hours per year. Use 8784 in leap years and use 8760 in all other years.

$GHG_{i,p}$ = Mole fraction of GHG (either CH_4 or CO_2) in the vent gas for centrifugal compressor p in operating mode; use the appropriate gas compositions in paragraph (u)(2) of this section.

GHG_{EF} = Mole fraction of GHG (either CH_4 or CO_2) used in the determination of $EF_{s,p}$. Use 0.95 for CH_4 and 0.05 for CO_2.

(11) *Method for converting from volumetric to mass emissions.* You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(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 CH_4 and CO_2 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)(9), you must calculate volumetric emissions as specified in paragraph (p)(10) of this section and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n). If emissions from a compressor source are routed to combustion, paragraphs (p)(1) through (11) of this section 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 a vapor recovery system, paragraphs (p)(1) through (11) of this section do not apply.

(1) *General requirements for conducting volumetric emission measurements.* You must conduct volumetric emission measurements on each reciprocating compressor as specified in this paragraph. Compressor sources (as defined in § 98.238) without manifolded vents must use a measurement method specified in paragraph (p)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in § 98.238) must use a measurement method specified in paragraph (p)(1)(i), (ii), (iii), or (iv) of this section.

(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.

(ii) *Reciprocating compressor source continuous monitoring.* Instead of measuring the compressor source according to paragraph (p)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (p)(3) of this section.

(iii) *Manifolded reciprocating compressor source as found measurements.* For a compressor source that is part of a manifolded group of compressor sources (as defined in § 98.238), instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (p)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (p)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) *Manifolded reciprocating compressor source continuous monitoring.* For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressors sources as specified in paragraph (p)(5) 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.

(i) *For blowdown valves on compressors in operating-mode or 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 (p)(2)(i)(A) through (D) of this section.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer, according to methods set forth in § 98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(D) You may choose to use any of the methods set forth in § 98.234(a) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a), then you must use one of the methods specified in paragraphs (p)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a), 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.

(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.

(A) Determine the volumetric flow at standard conditions from the open-ended vent line using calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the open-ended vent line using a temporary meter such as a vane anemometer, according to methods set forth in § 98.234(b).

(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 paragraphs (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) For reciprocating rod packing not equipped with an open-ended vent line on compressors in operating-mode, you must determine the volumetric emissions using the method specified in paragraphs (p)(2)(iii)(A) and (B) of this section.

(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.

(B) You must measure emissions found in paragraph (p)(2)(iii)(A) of this section using an appropriate meter, calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(3) *Methods for continuous measurement from individual reciprocating compressor sources.* If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (p)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (p)(3)(i) and (p)(3)(ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor sources at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) *Methods for performing as found measurements from manifolded groups of reciprocating compressor sources.* If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (p)(4)(i) and (ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraph (p)(4)(ii)(A) through (F) of this section.

(C) A high volume sampler according to methods set forth in § 98.234(d).

(D) [Reserved]

(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 paragraphs (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.

(F) If one of the screening methods specified in § 98.234(a)(1) through (3) identifies a leak in a manifolded group of reciprocating compressor sources, you may use acoustic leak detection, according to § 98.234(a)(5), to identify the source of the leak. You must use one of the methods specified in paragraphs (p)(4)(ii)(A) through (D) of this section to quantify the emissions from the identified source.

(5) *Methods for continuous measurement from manifolded groups of reciprocating compressor sources.* If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (p)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in § 98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) *Method for calculating volumetric GHG emissions from as found measurements for individual reciprocating compressor sources.* For compressor sources measured according to paragraph (p)(1)(i) of this section, you must calculate GHG emissions from the compressor sources as specified in paragraphs (p)(6)(i) through (iv) of this section.

(i) Using equation W–26 to this section, calculate the annual volumetric GHG emissions for each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-26)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (p)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination m, for which Es,i,m is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section that was measured for the reporting year.

(ii) Using equation W–27 to 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.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-27)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (p)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which Es,i,m is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section that was not measured for the reporting year.

(iii) Using equation W–28 to 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 to this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \quad \text{(Eq. W-28)}$$

Where:

$EF_{s,m}$ = Reporter emission factor to be used in equation W–27 to this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in equation W–26 to this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section.

(iv) The reporter emission factor in equation W–28 to this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) *Method for calculating volumetric GHG emissions from continuous monitoring of individual reciprocating compressor sources.* For compressor sources measured according to paragraph (p)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using equation W–29A to this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \qquad \text{(Eq. W-29A)}$$

Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) *Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of reciprocating compressor sources.* For manifolded groups of compressor sources measured according to paragraph (p)(1)(iii) of this section, you must calculate annual GHG emissions using equation W–29B to this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(8) or paragraph (o)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \qquad \text{(Eq. W-29B)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

T_g = 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.

$MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (p)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) *Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of reciprocating compressor sources.* For a manifolded group of compressor sources measured according to paragraph (p)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using equation W–29C to this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(9) or paragraph (o)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \qquad \text{(Eq. W-29C)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(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 volumetric emissions from reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (p)(10)(i) through (iv) of this section, as applicable.

(i) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct the volumetric emission measurements as required by § 60.5385b(b) and (c) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, conduct any additional volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section (based on the compressor mode (as defined in

§ 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (p)(6) through (9) of this section. Conduct all measurements required by this paragraph (p)(10)(i) at the frequency specified by § 60.5385b(a) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5385b(a) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (p)(6)(ii) of this section.

(ii) For all reciprocating compressors 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 the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may elect to conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (p)(6) through (9) of this section.

(iii) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (p)(10)(i) of this section does not apply, and you do not elect to conduct volumetric emission measurements specified in paragraph (p)(1) of this section, you must calculate total atmospheric rod packing emissions from all reciprocating compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using equation W–29D to this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (p).

$$E_{s,i} = \sum_{p=1}^{Count} E_{s,i,p} \qquad \text{(Eq. W-29D)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from all reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors with rod packing emissions vented directly to the atmosphere.

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for reciprocating compressor p, at standard conditions, in cubic feet, calculated using equation W–29E to this section.

(iv) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (p)(10)(i) of this section does not apply, you must calculate rod packing vent emissions from each reciprocating compressor using equation W–29E to this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (p).

$$E_{s,i,p} = EF_{s,p} \times \frac{T_p}{T_{total}} \times \frac{GHG_{i,p}}{GHG_{EF}} \qquad \text{(Eq. W-29E)}$$

Where:

$E_{s,i,p}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for reciprocating compressor p, at standard conditions, in cubic feet.

$EF_{s,p}$ = Emission factor for reciprocating compressor p, in standard cubic feet per year. Use 2.13×10^5 standard cubic feet per year per compressor for CH_4 and 1.18×10^4 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

T_p = Total time reciprocating compressor p was in operating mode, for which $E_{s,i,p}$, is being calculated in the reporting year, in hours.

T_{total} = Total hours per year. Use 8784 in leap years and use 8760 in all other years.

$GHG_{i,p}$ = Mole fraction of GHG (either CH_4 or CO_2) in the vent gas for reciprocating compressor p in operating mode; use the appropriate gas compositions in paragraph (u)(2) of this section.

GHG_{EF} = Mole fraction of GHG (either CH_4 or CO_2) used in the determination of $EF_{s,p}$. Use 0.98 for CH_4 and 0.02 for CO_2.

(11) *Method for converting from volumetric to mass emissions.* You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) and (v) 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) and (vi) 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) and (vi) 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. Equipment leak components in vacuum service are exempt from the survey and emission estimation requirements of this paragraph (q) and only the count of these equipment must 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, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b 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, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, and are required to conduct surveys using any of the leak detection methods in § 98.234(a)(1)(ii) or (iii) or (a)(2)(ii), as applicable, you must use the results of those surveys to 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 or are not required to conduct surveys using the methods in § 98.234(a) in accordance with the fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b 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 paragraph (q)(1)(iv) of this section, 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 or are not required to conduct surveys using the methods in § 98.234(a) in accordance with the fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b 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 for onshore natural gas processing plants in § 60.5400b or § 60.5401b 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 for onshore natural gas processing plants in § 60.5400b 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) For the components listed in § 98.232(m)(3)(ii) and (m)(4)(ii), 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). If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(m)(3)(ii) and (m)(4)(ii) 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(m)(3)(ii) and (m)(4)(ii) using the procedures in either paragraph (q)(2) or (3) of this section.

(vii) Except as provided in paragraph (q)(1)(viii) 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)(vii)(A) through (H) 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 (vi) 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 using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(B) For components subject to the well site, centralized production facility, and compressor station fugitive emissions standards in § 60.5397b or 60.5398b of this chapter, each survey conducted in accordance with the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b, 60.5398b(b)(4) or 60.5398b(b)(5)(ii) of this chapter using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(C) For components subject to the well site, centralized production facility, 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 using one of the methods in § 98.234(a) 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 and boosting 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 § 60.5400b or § 60.5401b 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 § 60.5400b or § 60.5401b 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. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered difficult-to-monitor emission sources as specified in § 98.234(a). Inaccessible components as provided in §§ 60.5401b(h)(3) and 60.5401c(h)(3) of this chapter are exempt from the monitoring requirements in this subpart.

(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.

(H) For onshore natural gas transmission pipeline facilities that conduct leak detection surveys according to paragraph (q)(1)(vi) of this section, a survey of all required components at a transmission company interconnect metering-regulating station or a farm tap/direct sale metering-regulating station, will be considered a complete leak detection survey for purposes of this section.

(viii) 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 not to measure leaks according to Calculation Method 2 as specified in paragraph (q)(3) of this section, you must use this Calculation Method 1 for all components included in a complete leak survey. For industry segments listed in § 98.230(a)(2) through (10), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (vi) of this section, then you must calculate equipment leak emissions per component type per reporting facility, well-pad site, or gathering and boosting site, as applicable, using equation W–30 to this section and the requirements specified in paragraphs (q)(2)(i) through (x) and (xii) of this section. For the industry segment listed in § 98.230(a)(8), the results from equation W–30 to this section are used to calculate population emission factors on a meter/regulator run basis using equation W–31 to 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)(viii) 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.

$$E_{s,p,i} = GHG_i \times EF_{sp} \times \sum_{z=1}^{x_p} T_{p,z} \times k \qquad \text{(Eq. W-30)}$$

Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHG_i from specific component type ''p'' (in accordance with paragraphs (q)(1)(i) through (vi) of this section) in standard (''s'') cubic feet, as specified in paragraphs (q)(2)(ii) through (x) and (xii) of this section.

x_p = Total number of specific component type ''p'' detected as leaking in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$EF_{s,p}$ = Leaker emission factor as specified in paragraphs (q)(2)(iii) through (x) and (xii) of this section.

k = Factor to adjust for undetected leaks by respective leak detection method, where k equals 1.25 for the methods in § 98.234(q)(1), (3) and (5); k equals 1.55 for the method in § 98.234(q)(2)(i); and k equals 1.27 for the method in § 98.234(q)(2)(ii).

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2 or concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for LNG storage and LNG import and export equipment and onshore natural gas transmission pipeline, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

$T_{p,z}$ = The total time the surveyed component ''z,'' component type ''p,'' was assumed to be leaking and operational, in hours. 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; and sum times for all leaking periods. 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.

(i) The leak detection surveys selected for use in equation W–30 to this section must be conducted during the calendar year as indicated in paragraph (q)(1)(vii) and (viii) of this section, as applicable.

(ii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(iii) Onshore petroleum and natural gas production facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or 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–2 to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default whole gas leaker factors for components in gas service listed in table W–2 to this subpart.

(v) Onshore natural gas processing facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or 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–4 to this subpart.

(vi) Onshore natural gas transmission compression facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or 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–4 to this subpart.

(vii) Underground natural gas storage facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in table W–4 to this subpart.

(viii) LNG storage facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in table W–6 to this subpart.

(ix) LNG import and export facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in table W–6 to this subpart.

(x) Except as provided in paragraph (q)(3)(viii) of this section, natural gas distribution facilities must use equation W–30 to this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in table W–6 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 to this section to determine the meter/regulator run population emission factors for each GHG_i. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHG_i 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 to this section.

p = Seven component types listed in table W–6 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)(viii) 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 to 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 to this section 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 to this section 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 to this section 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)(viii) of this section, you must use the meter/regulator run population emission factors calculated using equation W–31 to 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 to this section.

(xii) Onshore natural gas transmission pipeline facilities must use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of this section.

(3) *Calculation Method 2: Leaker measurement methodology.* For industry segments listed in § 98.230(a)(2) through (10), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (vi) of this section, you may elect to measure the volumetric flow rate of each natural gas leak identified during a complete leak survey. If you elect to use this method, you must use this method for all components included in a complete leak survey and you must determine the volumetric flow rate of each natural gas leak identified during the leak survey and aggregate the emissions by the method of leak detection and 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. If you are unable to measure the natural gas leak because it would require elevating the measurement personnel more than 2 meters above the surface and a lift is unavailable at the site or it would pose immediate danger to measurement personnel, then you must substitute the default leak rate for the component and site type from tables W–2, W–4, or W–6 to this subpart, as applicable, as the measurement for this leak.

(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 by the method used for the survey for which a leak was detected.

(vii) Multiply the total CO_2 and CH_4 mass emissions by survey method and component type determined in paragraph (q)(3)(vi) by the survey specific value for ''k'', the factor adjustment for undetected leaks, where k equals 1.25 for the methods in § 98.234(q)(1), (3) and (5); k equals 1.55 for the method in § 98.234(q)(2)(i); and k equals 1.27 for the method in § 98.234(q)(2)(ii).

(viii) For natural gas distribution facilities:

(A) Use equation W–31 to 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 sum of the GHG volumetric emissions for each type of component required to be surveyed by the method used for the survey for which a leak was detected calculated in paragraph (q)(3)(iv) of this section rather than the emissions calculated using equation W–30 to this section.

(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 to this section.

(4) *Development of facility-specific component-level leaker emission factors by leak detection method.* If you elect to measure leaks according to Calculation Method 2 as specified in paragraph (q)(3) of this section, you must use the measurement values determined in accordance with paragraph (q)(3) of this section to calculate a facility-specific component-level leaker emission factor by leak detection method as provided in paragraphs (q)(4)(i) through (iv) of this section.

(i) You must track the leak measurements made separately for each of the applicable components listed in paragraphs (q)(1)(i) through (v) of this section and by the leak detection method according to the following three bins.

(A) Method 21 as specified in § 98.234(a)(2)(i).

(B) Method 21 as specified in § 98.234(a)(2)(ii).

(C) Optical gas imaging (OGI) and other leak detection methods as specified in § 98.234(a)(1), (3), or (5).

(ii) You must accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a facility-specific component-level leaker emission factor for use in calculating emissions according to paragraph (q)(2) of this section (Calculation Method 1: Leaker emission factor calculation methodology).

(iii) Sum the volumetric flow rate of natural gas determined in accordance with paragraph (q)(3)(i) of this section for each leak by component type and leak detection method as specified in paragraph (q)(4)(i) of this section meeting the minimum number of measurement requirement in paragraph (q)(4)(ii) of this section.

(iv) Convert the volumetric flow rate of natural gas determined in paragraph (q)(4)(iii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(v) Determine the emission factor in units of standard cubic feet per hour component (scf/hr-component) by dividing the sum of the volumetric flow rate of natural gas determined in paragraph (q)(4)(iv) of this section by the total number of leak measurements for that component type and leak detection method combination.

(vi) You must update the emission factor determined in (q)(4)(v) of this section annually to include the results from all complete leak surveys for which leak measurement was performed during the reporting year in accordance with paragraph (q)(3) 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), (j)(10)(ii), (m)(3)(i), and (m)(4)(i) 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), (j)(11), and (m)(5). 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 this paragraph (r) and do not need to be reported. Equipment leak components in vacuum service are exempt from the survey and emission estimation requirements of this paragraph (r) and only the count of these equipment must be reported. You must calculate emissions from all emission sources listed in this paragraph (r) using equation W–32A to 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 to this section and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \qquad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \qquad \text{(Eq. W-32B)}$$

Where:

$E_{s,e,i}$ = 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, gathering pipeline, transmission company interconnect metering-regulating station, farm tap and/or direct sale metering-regulating station, or transmission 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–1 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–3 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–5 to this subpart. Onshore natural gas transmission pipeline facilities must count the following, as listed in table W–5 to this subpart: (1) Miles of transmission pipelines by material type; (2) number of transmission company interconnect metering-regulating stations; and (3) number of farm tap and/or direct sale metering-regulating stations.

$Count_{MR}$ = 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 specified in paragraphs (r)(2) through (7) of this section.

$EF_{s,MR,i}$ = 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, as determined in equation W–31 to this section.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2 or concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution and onshore natural gas transmission pipeline, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_e = Average estimated time that each emission source type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$T_{w,avg}$ = Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run, using engineering estimate based on best available data.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(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–1 to this subpart. Major equipment associated with gas wells are considered gas service equipment in table W–1 to this subpart. Onshore petroleum and natural gas gathering and boosting facilities shall use the gas service equipment emission factors in table W–1 to this subpart. Major equipment associated with crude oil wells are considered crude service equipment in table W–1 to this subpart. Where facilities conduct EOR operations, the emission factor listed in table W–1 to 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.

(3) Underground natural gas storage facilities must use the appropriate default total hydrocarbon population emission factors for storage wellheads in gas service listed in table W–3 to this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factors for LNG storage compressors in gas service listed in table W–5 to this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factors for LNG terminal compressors in gas service listed in table W–5 to this subpart.

(6) Natural gas distribution facilities must use the appropriate methane emission factors as described in paragraphs (r)(6)(i) and (ii) of this section.

(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–5 to 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 to this section in accordance with paragraph (q)(2)(x) or (q)(3)(viii)(A) of this section 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).

(7) Onshore natural gas transmission pipeline facilities must use the appropriate default methane population emission factors listed in table W–5 to this subpart to estimate emissions from components listed in § 98.232(m)(3)(i), (4)(i) and (5).

(s) *Offshore petroleum and natural gas production facilities.* Calculate CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks (*i.e.,* fugitives), vented emission, and flare emission source types as identified by BOEM in the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304.

(1) Offshore production facilities that report to BOEM's emissions inventory must calculate emissions as specified in paragraph (s)(1)(i) or (ii) of this section, as applicable.

(i) Report the same annual emissions calculated using the most recent monitoring and calculation methods published by BOEM as referenced in 30 CFR 550.302 through 304 for any reporting year that overlaps with a BOEM emissions inventory year and any other reporting year in which the BOEM's emissions reporting system is available and the facility has the data needed to use BOEM's emissions reporting system.

(ii) If BOEM's emissions reporting system is not available or if the facility does not have the data needed to use BOEM's emissions reporting system, adjust emissions from the most recent emissions calculated in accordance with paragraph (s)(1)(i), (s)(3), or (s)(4) of this section, as applicable, by using a ratio of the operating time for the facility in the current reporting year relative to the operating time for the facility during the reporting year for which emissions were calculated as specified in paragraph (s)(1)(i), (s)(3), or (s)(4) of this section, as applicable.

(2) Offshore production facilities that do not report to BOEM's emissions inventory must calculate emissions as specified in paragraph (s)(2)(i) or (ii) of this section, as applicable.

(i) Use the most recent monitoring and calculation methods published by BOEM as referenced in 30 CFR 550.302 through 304 to calculate and report annual emissions for any reporting year that overlaps with a BOEM emissions inventory year and any other reporting year in which the facility has the data needed to use BOEM's emissions calculation methods.

(ii) If the facility does not have the data needed to use BOEM's calculation methods, adjust emissions from the facility's most recent emissions calculated in accordance with paragraph (s)(2)(i), (s)(3), or (s)(4) of this section, as applicable, by using a ratio of the operating time for the facility in the current reporting year relative to the operating time for the facility in the reporting year for which the emissions were calculated as specified in paragraph (s)(2)(i), (s)(3), or (s)(4) of this section, as applicable.

(3) If BOEM's emissions inventory is discontinued or delayed for more than 3 consecutive years, then offshore production facilities shall once in every 3 years use the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate annual emissions for each of the emission source types covered in BOEM's most recently published calculation methods.

(4) For the first year of reporting, offshore production facilities must use the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate and report annual emissions.

(t) GHG volumetric emissions using actual conditions. If equation parameters in § 98.233 are already determined at standard conditions as provided in the introductory text in § 98.233, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraph (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and equation W–33 to this section for conversions of $E_{a,n}$ or conversions of FR_a (whether sub-sonic or sonic).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \quad \text{(Eq. W-33)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet, except $E_{s,n}$ equals $FR_{s,p}$ for each well p when calculating either subsonic or sonic flowrates under § 98.233(g).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet, except $E_{a,n}$ equals $FR_{a,p}$ for each well p when calculating either subsonic or sonic flowrates under § 98.233(g).

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and equation W–34 to this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \quad \text{(Eq. W-34)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

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.

(3) Reporters using 68 °F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68 °F to 60 °F.

(u) *GHG volumetric emissions at standard conditions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using equation W–35 to this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For equation W–35 to this section, the mole fraction, M_i, shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) *GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities.* If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

(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).

(iii) *GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment and the onshore natural gas transmission pipeline industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(iv) *GHG mole fraction in natural gas stored in the underground natural gas storage industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) *GHG mole fraction in natural gas stored in the LNG storage industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vi) *GHG mole fraction in natural gas stored in the LNG import and export industry segment.* For export facilities that receive gas from transmission pipelines, you may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vii) *GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) *GHG mass emissions.* Calculate GHG mass emissions in metric tons by converting the GHG volumetric emissions at standard conditions into mass emissions using equation W–36 to this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \qquad \text{(Eq. W-36)}$$

Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons.

$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60 °F and 14.7 psia.

(w) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions from each EOR injection pump system as follows:

(1) Calculate the total injection pump system volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual CO_2 emissions from each EOR injection pump system using equation W–37 to this section:

$$Mass_{CO_2} = N * V_v * R_c * GHG_{CO_2} * 10^{-3} \qquad \text{(Eq. W-37)}$$

Where:

$Mass_{CO_2}$ = Annual EOR injection pump system emissions in metric tons from blowdowns.

N = Number of blowdowns for the EOR injection pump system in the calendar year.

V_v = Total volume in cubic feet of EOR injection pump system chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3. 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 to determine density of super critical EOR injection gas.

GHG_{CO_2} = Mass fraction of CO_2 in critical phase injection gas.

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

(x) *EOR hydrocarbon liquids dissolved CO_2.* Calculate CO_2 emissions downstream of the storage tank from dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples of hydrocarbon liquids downstream of the storage tank must be taken according to methods set forth in § 98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using equation W–38 to this section.

$$Mass_{CO_2} = S_{hl} * V_{hl} \qquad \text{(Eq. W-38)}$$

Where:

$Mass_{CO_2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) *Other large release events.* Calculate CO_2 and CH_4 emissions from other large release events as specified in paragraphs (y)(2) through (5) of this section for each release that meets or exceeds the applicable criteria in paragraph (y)(1) of this section. You are not required to measure every release from your facility, but if you have EPA-provided notification(s) under the super emitter program in § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or if EPA- or facility-funded monitoring or measurement data that demonstrate the release meets or exceeds one of the thresholds or may reasonably be anticipated to meet or exceed (or to have met or exceeded) one of the thresholds in paragraph (y)(1) of this section, then you must calculate the event emissions and, if the thresholds are confirmed to be exceeded, report the emissions as an other large release event. If you receive an EPA-provided notification under the super emitter program in § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must comply with the requirements in paragraph (y)(6) of this section.

(1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraphs (y)(1)(i) or (ii) of this section. You must report the emissions for the entire duration of the event, not just those time periods of the event emissions exceed the thresholds in paragraphs (y)(1)(i) or (ii) of this section.

(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that emits methane at any point in time at a rate of 100 kg/hr or greater.

(ii) For sources subject to reporting under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) of this section, a release that emits methane at any point in time at a rate of 100 kg/hr or greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) of this section. For a release meeting the criteria in this paragraph (y)(1)(ii), you must report the emissions as an other large release event and exclude the emissions that would have been calculated for that source during the timespan of the event in the source-specific emissions calculated under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) of this section, as applicable.

(2) Estimate the total volume of gas released during the event in standard cubic feet and the methane emission rate at any point in time during the event in kilograms per hour using measurement data according to § 98.234(b), if available, or a combination of process knowledge, engineering estimates, and best available data when measurement data are not available according to paragraphs (y)(2)(i) through (v) of this section.

(i) The total volume of gas released must be estimated as the product of the measured or estimated average flow or release rate and the estimated event duration. For events for which information is available showing variable or decaying flow rates, you must calculate the maximum natural gas flow or release rate during the event and either determine a representative average release rate across the entire event or determine representative release rates for specific time periods within the event duration. If you elect to determine representative release rates for specific time periods within the event duration, calculate the volume of gas released for each time period within the event duration as the product of the representative release rate and the length of the corresponding time period and sum the volume of gas released across each of the time periods for the full duration of the event. For events that have releases from multiple release points but have a common root cause (*e.g.*, over-pressuring of a system causes releases from multiple pressure relief devices), you must report the event as a single other large release event considering the cumulative volume of gas released across all release points.

(ii) The start time of the event must be determined based on monitored process parameters and sound engineering principles. If monitored process parameters cannot identify the start of the event, the event must be assumed to start on the date of the most recent monitoring or measurement survey that confirms the source was not emitting at or above the rates specified in paragraph (y)(1) of this section or assumed to have started 91 days prior to the date the event was first identified, whichever start date is most recent.

(iii) The end time of the event must be the date of the confirmed repair or confirmed cessation of emissions.

(iv) For the purposes of paragraph (y)(2)(ii) of this section, ''monitoring or measurement survey'' includes any monitoring or measurement method in § 98.234(a) through (d) as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying emissions at the thresholds specified in paragraph (y)(1) of this section at a 90 percent probability of detection as demonstrated by controlled release tests. Audio, visual, and olfactory inspections are considered monitoring surveys if and only if the event was identified via an audio, visual, and olfactory inspection.

(v) For events that span two different reporting years, calculate the portion of the event's volumetric emissions calculated according to paragraph (y)(2)(i) of this section that occurred in each reporting year considering only reporting year 2025 and later reporting years. For events with consistent flow or for which one average emissions rate is used, use the relative duration of the event within each reporting year to apportion the volume of gas released for each reporting year. For variable flow events for which the volume of gas released is estimated for separate time periods, sum the volume of gas released across each of the time periods within a given reporting year separately. If one of the time periods span two different reporting years, calculate the portion of the volumetric emissions calculated for that time period that applies to each reporting year based on the number of hours in that time period within each reporting year.

(3) Determine the composition of the gas released to the atmosphere using measurement data, if available, or a combination of process knowledge, engineering estimates, and best available data when measurement data are not available. 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 released directly to the atmosphere and the fraction of natural gas that was combusted by the explosion or fire during the release event. Assume combustion efficiency equals destruction efficiency and assume a maximum combustion efficiency of 92 percent for natural gas that is combusted in an explosion or fire when estimating the CO_2 and CH_4 composition of the release. You may use different compositions for different periods within the duration if available information suggests composition varied during the release (*e.g.*, if a portion of the release occurred while fire was present and a portion of the release occurred when no fire was present).

(4) Calculate the GHG volumetric emissions using equation W–35 to this section.

(5) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(6) If you receive an EPA-provided notification under the super emitter program in § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must include the emissions from that source or event within your subpart W report unless you can provide certification as specified in either paragraph (y)(6)(i) or (ii) of this section, as applicable, or unless the EPA has determined that the notification has a demonstrable error, as specified in paragraph (y)(6)(iii) of this section.

(i) If you do not own or operate any petroleum and natural gas system equipment within 50 meters of the location identified in the notification, you may prepare and submit the certification that the facility does not own or operate the equipment at the location identified in the notification.

(ii) If you own or operate petroleum and natural gas system equipment within 50 meters of the location identified in the notification, but there are also other petroleum and natural gas system equipment within 50 meters of the location identified in the notification owned and operated by a different facility, you may prepare and submit the certification that the facility does not own or operate the emitting equipment at the location identified in the notification if and only if you comply with all of the following requirements.

(A) Within 5 days of receiving the notification, complete an investigation of available data as specified in § 60.5371b(d)(2)(i) through (iv) of this chapter to identify the emissions source related to the event notification.

(B) If the data investigation in paragraph (y)(6)(ii)(A) of this section does not identify the emissions source related to the event notification, you must conduct a complete survey of equipment at your facility that is within 50 meters of the location identified in the notification following any one of the methods provided in § 98.234(a)(1) through (3) within 15 days of receiving the notification.

(C) The investigations and surveys conducted in paragraphs (y)(6)(ii)(A) and (B) of this section verify that none of the equipment that you own or operate at the location identified in the notification were responsible for the high emissions event.

(iii) For consideration of demonstrable error, you must submit a statement of demonstrable error as specified by § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. You must report emissions associated with the notification unless the EPA has determined that the notification contained a demonstrable error.

(z) *Combustion equipment.* Except as specified in paragraphs (z)(6) and (7) 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 to 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 for each unit or group of units combusting the same fuel according to any Tier listed in subpart C of this part, except that each natural gas-fired reciprocating internal combustion engine or gas turbine must use one of the methods in paragraph (z)(4) of this section to quantify a CH_4 emission factor instead of using the CH_4 emission factor in table C–2 to 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)(5) 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 with only fuels that are listed in table C–1. The natural gas 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 higher heating value of 1,100 Btu per standard cubic foot.

(C) The natural gas must have a minimum CH_4 content of 70 percent by volume.

(ii) For fuels listed in paragraph (z)(2)(i) of this section, calculate CO_2, CH_4, and N_2O emissions for each unit or group of units combusting the same fuel according to Tier 2, Tier 3, or Tier 4 listed in subpart C of this part, except that each natural gas-fired reciprocating engine or gas turbine must use one of the methods in paragraph (z)(4) of this section to quantify a CH_4 emission factor instead of using the CH_4 emission factor in table C–2 to 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)(5) 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 combusted in the stationary or portable equipment does not meet the criteria of either paragraph (z)(1)(i) or (z)(2)(i) of this section. Examples include natural gas that is not of pipeline quality, 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 criteria of either paragraph (z)(2)(i)(B) or (C) of this section. Other examples include 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 using the applicable steps from paragraphs (z)(3)(ii)(A) through (G) of this section:

(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 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 constituent in the flow of gas to the unit or group of units. Otherwise, you must use the appropriate gas compositions for each stream going to the combustion unit(s) as specified in paragraph (u)(2) of this section.

(C) For reciprocating internal combustion engines or gas turbines, you may conduct a performance test following the applicable procedures in § 98.234(i) and calculate CH_4 emissions in accordance with paragraph (z)(3)(ii)(G) of this section. Otherwise, you must calculate CH_4 emissions in accordance with paragraphs (z)(3)(ii)(D) through (F) of this section.

(D) Calculate GHG volumetric emissions at actual conditions using equations W–39A and W–39B to this section:

$$E_{a,CO_2} = (V_a * Y_{CO_2}) \quad + \quad \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. W-39A)}$$

$$E_{a,CH_4} = V_a * (1-\eta) * Y_{CH_4} \quad \text{(Eq. W-39B)}$$

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.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices that are not reciprocating internal combustion engines or gas turbines, a default of 0.995 can be used. For two-stroke lean-burn reciprocating internal combustion engines, a default of 0.953 must be used; for four-stroke lean-burn reciprocating internal combustion engines, a default of 0.962 must be used; for four-stroke rich-burn reciprocating internal combustion engines, a default of 0.997 must be used, and for gas turbines, a default of 0.999 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.

E_{a,CH_4} = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

Y_{CH4} = Mole fraction of methane in gas sent to the combustion unit or group of units.

(E) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(F) 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.

(G) Calculate CH_4 and N_2O mass emissions, as applicable, using equation W–40 to this section.

$$Mass_i = \left(1 \times 10^{-3}\right) \times Fuel \times HHV \times EF_i \quad \text{(Eq. W-40)}$$

Where:

$Mass_i$ = Annual N_2O or CH_4 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 = Site-specific higher heating value of the fuel, mmBtu/unit of the fuel (in units consistent with the fuel quantity combusted).

EF_i = For N_2O, use 1.0×10^{-4} kg N_2O/mmBtu; for CH_4, use the CH_4 EF (kg CH_4/MMBtu) determined from your performance test according to paragraph (z)(4)(i) of this section.

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

(4) For each natural gas-fired reciprocating internal combustion engine or gas turbine calculating emissions according to paragraph (z)(1)(ii) or (z)(2)(ii) of this section, you must determine a CH_4 emission factor (kg CH_4/MMBtu) using one of the methods provided in paragraphs (z)(4)(i) through (iii) of this section. For each reciprocating internal combustion engine or gas turbine calculating CH_4 emissions according to paragraph (z)(3)(ii)(G) of this section, you must determine a CH_4 emission factor (kg CH_4/MMBtu) using the method provided in paragraph (z)(4)(i).

(i) Conduct a performance test following the applicable procedures in § 98.234(i). If you are required or elect to conduct a performance test for any reason, you must use that result to determine the CH_4 emission factors. If multiple performance tests are conducted in the same reporting year, the arithmetic average of all performance tests completed that year must be used to determine the CH_4 emission factor.

(ii) Original equipment manufacturer information, which may include manufacturer specification sheets, emissions certification data, or other manufacturer data providing expected emission rates from the reciprocating internal combustion engine or gas turbine.

(iii) Applicable equipment type-specific emission factor from table W–7 to this subpart.

(5) 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.

(6) 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.

(7) 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.

(aa) through (cc) [Reserved]

(dd) *Drilling mud degassing.* Calculate annual volumetric CH_4 emissions from the degassing of drilling mud using one of the calculation methods described in paragraphs (dd)(1), (2), or (3) of this section. If you have taken mudlogging measurements from the penetration of the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore, including mud pumping rate and gas trap-derived gas concentration that is reported in parts per million (ppm) or is reported in units from which ppm can be derived, you must use Calculation Method 1 as described in paragraph (dd)(1) of this section. If you have not taken mudlogging measurements, you must use Calculation Method 2 as described in paragraph (dd)(2) of this section. If you have taken mudlogging measurements for some, but not all, of the time the well bore has penetrated the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore including mud pumping rate and gas trap-derived gas concentration that is reported in parts per million (ppm) or is reported in units from which ppm can be derived, you must use Calculation Method 3 as described in paragraph (dd)(3) of this section.

(1) *Calculation Method 1.* For each well in the sub-basin in which drilling mud was used during well drilling, you must calculate CH_4 emissions from drilling mud degassing by applying an emissions rate derived from a representative well in the same sub-

basin and within the equivalent stratigraphic interval. You must follow the procedures specified in paragraph (dd)(1)(i) of this section to calculate CH_4 emissions for the representative well and follow the procedures in paragraphs (dd)(1)(ii) through (iv) of this section to calculate CH_4 emissions for every well drilled in the sub-basin and within the equivalent stratigraphic interval.

(i) Calculate CH_4 emissions from mud degassing for one representative well in each sub-basin and within the equivalent stratigraphic interval. For the representative well, you must use mudlogging measurements, including gas trap derived gas concentration and mud pumping rate, taken during the reporting year. In the first year of reporting, you may use measurements from the prior reporting year if measurements from the current reporting year are not available. Use equation W–41 to this section to calculate natural gas emissions from mud degassing at the representative well. You must identify and calculate CH_4 emissions for a representative well for the sub-basin and within the equivalent stratigraphic interval every 2 calendar years or on a more frequent basis. If a representative well is not available in the same sub-basin and within the equivalent stratigraphic interval, you may choose a well within the facility that is drilled into the same formation and within the equivalent stratigraphic interval.

$$E_{s,CH_4,r} = MR_r \times T_r \times \frac{X_n}{1{,}000{,}000} \times GHG_{CH_4} \times 0.1337 \qquad \text{(Eq. W-41)}$$

Where:

$E_{s,CH4,r}$ = Annual total volumetric CH_4 emissions from mud degassing for the representative well, r, in standard cubic feet.

MR_r = Average mud rate for the representative well, r, in gallons per minute.

T_r = Total time that drilling mud is circulated in the representative well, r, in minutes beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore.

X_n = Average concentration of natural gas in the drilling mud as measured by the gas trap, in parts per million.

GHG_{CH4} = Measured mole fraction of CH_4 in natural gas entrained in the drilling mud.

0.1337 = Conversion from gallons to standard cubic feet.

(ii) Calculate the emissions rate of CH_4 in standard cubic feet per minute from the representative well using equation W–42 to this section.

$$ER_{s,CH_4,r} = \frac{E_{s,CH_4,r}}{T_r} \qquad \text{(Eq. W-42)}$$

Where:

$ER_{s,CH4,r}$ = Volumetric CH_4 emission rate from mud degassing for the representative well, r, in standard cubic feet per minute.

$E_{s,CH4,r}$ = Annual total volumetric CH_4 emissions from mud degassing for the representative well, r, in standard cubic feet.

T_r = Total time that drilling mud is circulated in the representative well, r, in minutes beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore.

(iii) Use equation W–43 to this section to calculate emissions for any wells drilled in the same sub-basin and within the equivalent stratigraphic interval in the reporting year.

$$E_{s,CH_4,p} = ER_{s,CH_4,r} \times T_p \qquad \text{(Eq. W-43)}$$

Where:

$E_{s,CH4,p}$ = Annual total CH_4 emissions from mud degassing for the well, p, in standard cubic feet.

$ER_{s,CH4,r}$ = Volumetric CH_4 emission rate from mud degassing for the representative well, r, in standard cubic feet per minute.

T_p = Total time that drilling mud is circulated in the well, p, during the reporting year, in minutes beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore.

(iv) Calculate CH_4 mass emissions using calculations in paragraph (v) of this section.

(2) *Calculation Method 2.* If you did not take mudlogging measurements, calculate emissions from mud degassing for each well using equation W–44 to this section:

$$Mass_{CH_4,p} = EF_{CH_4} \times DD_p \times \frac{X_{CH_4}}{83.85} \qquad \text{(Eq. W-44)}$$

Where:

$Mass_{CH4,p}$ = Annual total CH_4 emissions for the well, p, in metric tons.

EF_{CH4} = Emission factor in metric tons CH_4 per drilling day. Use 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds.

DD_p = Total number of drilling days for the well, p, when drilling mud is circulated in the wellbore. The first drilling day is the day that the borehole penetrated the first hydrocarbon-bearing zone and the last drilling day is the day drilling mud ceases to be circulated in the wellbore.

X_{CH4} = The mole percent of methane in gas vented during mud degassing in the sub-basin in which the well is located and derived from the average mole fraction of CH_4 in produced gas for the sub-basin as reported in § 98.236(aa)(1)(ii)(I).

83.85 = The mole percent of methane from the vented gas used to derive the emission factor (EF).

(3) *Calculation Method 3.* If you have taken mudlogging measurements at

intermittent time intervals for some, but not all, of the time the well bore has penetrated the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore, you must use Calculation Method 1 to calculate emissions for the cumulative amount of time mudlogging measurements were taken and Calculation Method 2 for the cumulative amount of time mudlogging measurements were not taken. To determine total annual CH_4 emissions for the well, add $Mass_{CH4,p}$ calculated using Calculation Method 2 to $E_{s,CH4,p}$, if the well is a representative well, or $E_{s,CH4,p}$, if the well is not a representative well, calculated using Calculation Method 1.

(ee) *Crankcase venting.* For each reciprocating internal combustion engine with a rated heat capacity greater than 1 mmBtu/hr (or the equivalent of 130 horsepower), calculate annual CH_4 mass emissions from crankcase venting using one of the methods provided in paragraphs (ee)(1) and (2) of this section. If you elect to use the method in paragraph (ee)(1) of this section, you must use the results of the direct measurement to determine the CH_4 emissions. If any crankcase vents are 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). Notwithstanding the calculation and emissions reporting requirements as specified in this paragraph (ee) of this section, the number of reciprocating internal combustion engines with crankcase vents routed to flares must be reported as specified in § 98.236(ee)(1).

(1) *Calculation Method 1.* Determine the CH_4 mass emissions from reciprocating internal combustion engines annually using the method provided in paragraphs (ee)(1)(i) through (iv) of this section. If you choose to use this method you must use it for all reciprocating internal combustion engines at the facility, well-pad site, or gathering and boosting site, except that if you choose to perform the screening specified in paragraph (ee)(1)(ii) of this section, you must use the method in paragraph (ee)(2) of this section to determine emissions from each reciprocating internal combustion engine that is not operating at the facility, well-pad site, or gathering and boosting site at the time of the screening.

(i) Determine the volumetric flow from the crankcase vent at standard conditions using an appropriate meter, calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively. Each measurement must be conducted within 10 percent of 100 percent peak load. You may not measure during period of startup, shutdown, or malfunction.

(ii) 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 the methods set forth in § 98.234(a)(1) through (3), then you must use one of the methods specified in paragraphs (ee)(1)(i) of this section to determine the volumetric flow from the crank case vent at standard conditions. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a)(1) through (3), emissions are detected whenever a leak is detected according to the method.

(iii) If conducting measurements for a manifolded group of crankcase vent sources, you must measure at a single point in the manifold downstream of all crankcase vent inputs and, if practical, prior to comingling with other non-compressor emission sources. Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraph (ee)(1)(i) of this section. If the manifolded group contains only crankcase vent sources, divide the measured volumetric flow equally between all operating reciprocating internal combustion engines. If the manifolded group contains crankcase vent sources and compressor vent sources, follow the methods for manifolded sources provided in paragraphs (o) or (p) of this section, as applicable, and report emissions from the crankcase vent as specified in § 98.236(o) or (p), as applicable.

(iv) Using equation W–45 to this section, calculate the annual volumetric CH_4 emissions for each reciprocating internal combustion engine that was measured during the reporting year.

$$E_{CH_4} = MT_{S,CCV} \times GHG_{CH_4} \times T \qquad \text{(Eq. W-45)}$$

Where:

E_{CH4} = Annual total volumetric emissions of CH_4 from crankcase venting on the reciprocating internal combustion engine, in standard cubic feet.

$MT_{s,CCV}$ = Volumetric gas emissions for measured crankcase vent, in standard cubic feet per hour, measured according to paragraph (ee)(1)(i) of this section.

GHG_{CH4} = Concentration of CH_4 in the gas stream entering reciprocating internal combustion engine. If the concentration of CH_4 is unknown, use the concentration of CH_4 in the gas stream either using engineering estimates based on best available data or as defined in paragraph (u)(2) of this section.

T = Total operating hours per year for the reciprocating internal combustion engine.

(v) You must calculate CH_4 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Calculation Method 2. Calculate annual CH_4 mass emissions from crankcase venting for each reciprocating internal combustion engine using equation W–46 to this section:

$$E_{CH_4} = EF \times 0.001 \times T \qquad \text{(Eq. W-46)}$$

Where:

E_{CH4} = Annual total mass emissions of CH_4 from crankcase venting on the reciprocating internal combustion engine, in metric tons.

EF = Emission factor for crankcase venting on the reciprocating internal combustion engine, in kilograms CH_4 per hour per reciprocating internal combustion engine. Use 0.083 kilograms CH_4 per hour per reciprocating internal combustion engine for sources in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments. Use 0.11 kilograms CH_4 per hour per reciprocating internal combustion engine for sources in all other applicable industry segments.

0.001 = Conversion from kilograms to metric tons.

T = Total operating hours per year for the reciprocating internal combustion engine.

■ 14. Amend § 98.234 by:
■ a. Revising the introductory text, paragraphs (a)(1) through (3), and (a)(5);
■ b. Removing paragraphs (a)(6) and (7);
■ c. Revising paragraph (d)(3);
■ d. Adding paragraph (d)(5);
■ e. Removing the text ''equation W–41'' and ''(Eq. W–41)'' in paragraph (e) and adding in its place the text ''equation W–47'' and ''(Eq. W–47)'', respectively;
■ f. Removing and reserving paragraphs (f) and (g); and
■ g. Adding paragraph (i).

The revisions and additions 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 part 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), (p), and (ee) 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. Difficult-to-monitor emissions sources are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor difficult-to-monitor 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 difficult-to-monitor 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 in § 98.233(q)(1).

(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 (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 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 in § 98.233(q)(1). 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 and § 60.5397b 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.

* * * * *

(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. If you elect to use OGI to demonstrate that 100 percent of the flow is captured by the high volume sampler throughout the measurement period, then the measured flow rate above the 70 percent maximum sampling rate provision can be used. However, if any emissions are observed via OGI escaping capture of the high volume sampler during a measurement period, then that measurement is considered invalid (*i.e.,* considered to be exceeding the quantitation capacity of the device) even if the measured flow rate is less than 70 percent of the sampling rate 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.

* * * * *

(e) Peng Robinson Equation of State means the equation of state defined by equation W–47 to this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \qquad \text{(Eq. W-47)}$$

(i) You must use any of the applicable methods described in paragraphs (i)(1) through (4) of this section to conduct a performance test to determine the concentration of CH4 in the exhaust gas. This concentration must be used to develop a CH4 emission factor (kg/MMBtu) for estimating combustion slip from reciprocating internal combustion engines or gas turbines as specified in § 98.233(z)(4). You may not conduct performance tests during period of startup, shutdown or malfunction. You must conduct three separate test runs for each performance test. Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(1) EPA Method 18 in appendix A–6 to part 60 of this chapter.

(2) EPA Method 320 in appendix A to part 63 of this chapter.

(3) ASTM D6348–12 (Reapproved 2020) (incorporated by reference, see § 98.7).

(4) EPA Method 25A in appendix A–7 to part 60 of this chapter, with the use of nonmethane cutter as described in § 1065.265 of this chapter.

■ 15. Amend § 98.235 by revising paragraph (f) to read as follows:

§ 98.235 Procedures for estimating missing data.

* * * * *

(f) For the first 6 months of required data collection, facilities that are currently subject to this subpart W and that start up new emission sources or acquire new sources from another facility that were not previously subject to this subpart W may use best engineering estimates for any data related to those newly operating or newly acquired sources that cannot reasonably be measured or obtained according to the requirements of this subpart.

* * * * *

■ 16. Effective July 15, 2024, amend § 98.236 by:

■ a. Revising paragraphs (b), (c), and (d)(2)(iii) introductory text;

■ b. Adding paragraph (d)(2)(iii)(M);

■ c. Revising paragraphs (e) introductory text, (e)(1) introductory text, (e)(2) introductory text, (e)(2)(i), and (g)(5) introductory text;

■ d. Adding paragraph (g)(5)(iv);

■ e. Revising paragraph (g)(6) introductory text;

■ f. Redesignating paragraph (g)(6)(iii) as (g)(6)(iv);

■ g. Adding new paragraph (g)(6)(iii);

■ h. Revising paragraphs (j)(2)(i)(A) and (m)(4) through (6);

■ i. Redesignating paragraphs (m)(7)(ii) and (iii) as (m)(7)(iii) and (iv), respectively;

■ j. Adding new paragraph (m)(7)(ii);

■ k. Revising paragraphs (o) introductory text, (p) introductory text, and (q)(1) introductory text;

■ l. Adding paragraph (q)(1)(vi); and

■ m. Revising paragraph (q)(2).

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

* * * * *

(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 (b)(6) of this section, as applicable.

(1) [Reserved]

(2) The number of natural gas pneumatic devices as specified in paragraphs (b)(2)(i) through (viii) of this section, as applicable.

(i) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed), determined according to § 98.233(a)(5) through (7).

(ii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere, determined according to § 98.233(a)(5) through (7).

(iii) [Reserved]

(iv) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1).

(v) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(a)(2).

(vi) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 3 according to § 98.233(a)(3).

(vii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) for which emissions were calculated using Calculation Method 4 according to § 98.233(a)(4).

(viii) If the reported values in paragraphs (b)(2)(i) through (vii) of this section are estimated values determined according to § 98.233(a)(6), then you must report the information specified in paragraphs (b)(2)(viii)(A) through (C) of this section.

(A) The number of natural gas pneumatic devices of each type reported in paragraphs (b)(2)(i) through (vii) of this section that are counted.

(B) The number of natural gas pneumatic devices of each type reported in paragraph (b)(2)(i) through (vii) 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.

(3) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1), report the information in paragraphs (b)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) downstream of the flow monitor.

(iv) An indication of whether a natural gas driven pneumatic pump is also downstream of the flow monitor.

(v) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(4) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(a)(2), report the information in paragraphs (b)(4)(i) or (ii) of this section, as applicable.

(i) For onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities:

(A) Indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(B) The average number of hours each type of the natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed) was in service (*i.e.,* supplied with natural gas) in the calendar year.

(C) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(D) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(ii) For onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, and natural gas distribution facilities:

(A) The number of years used in the current measurement cycle.

(B) Indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler) to measure the emissions from natural gas pneumatic devices at this facility.

(C) Indicate whether the emissions from any natural gas pneumatic devices at this facility were calculated using equation W–1B to § 98.233.

(D) If the emissions from any natural gas pneumatic devices at this facility were calculated using equation W–1B to § 98.233, report the following information for each type of natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(*1*) The value of the emission factor for the reporting year as calculated using equation W–1A to § 98.233 (in scf/hour/device).

(*2*) The total number of natural gas pneumatic devices measured across all years upon which the emission factor is based (*i.e.,* the cumulative value of ‘‘$\Sigma_{ny=1}$ $Count_{t,y}$’’ in equation W–1A to § 98.233).

(*3*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (‘‘$Count_t$’’ in equation W–1B to § 98.233).

(*4*) The average estimated number of hours in the operating year the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) (‘‘T_t’’ in equation W–1B to § 98.233).

(E) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(F) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(G) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this facility were monitored during the reporting year.

(H) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this facility were monitored during the reporting year.

(5) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 3 according to § 98.233(a)(3), report the information in paragraphs (b)(5)(i) through (iv) of this section.

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices:

(A) Indicate whether you measured emissions according to § 98.233(a)(3)(i)(A) or used default emission factors according to § 98.233(a)(3)(i)(B) to calculate emissions from your continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere.

(B) If measurements were made according to § 98.233(a)(3)(i)(A), indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(C) If default emission factors were used according to § 98.233(a)(3)(i)(B) to calculate emissions, report the following information for each type of applicable natural gas pneumatic device (continuous low bleed and continuous high bleed).

(*1*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (*i.e.,* "$Count_t$" in equation W–1B to § 98.233).

(*2*) The average estimated number of hours in the operating year that the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) ("T_t" in equation W–1B to § 98.233).

(ii) For intermittent bleed natural gas pneumatic devices:

(A) Indicate the primary monitoring method used (OGI; Method 21 at 10,000 ppm; Method 21 at 500 ppm; or infrared laser beam) and the number of complete monitoring surveys conducted.

(B) The total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (" × " in equation W–1C to § 98.233).

(C) Average time the intermittent bleed natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning in the calendar year (average value of "$T_{m,z}$" in equation W–1C to § 98.233).

(D) The total number of intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year ("Count" in equation W–1C to § 98.233).

(E) Average time the intermittent bleed natural gas pneumatic 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–1C to § 98.233).

(iii) Annual CO_2 emissions, in metric tons CO_2, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(iv) Annual CH_4 emissions, in metric tons CH_4, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(6) For natural gas pneumatic devices for which emissions were calculated using Calculation Method 4 according to § 98.233(a)(4), report the following information for each type of applicable natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(i) [Reserved]

(ii) The estimated average number of hours in the operating year that the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) ("T_t" in equation W–1B to § 98.233).

(iii) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices combined, calculated according to Calculation Method 4 in § 98.233(a)(4).

(iv) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined, calculated according to Calculation Method 4 in § 98.233(a)(4).

(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 (5) of this section.

(1) [Reserved]

(2) The number of natural gas driven pneumatic pumps as specified in paragraphs (c)(2)(i) through (iv) of this section, as applicable.

(i) The total number of natural gas driven pneumatic pumps.

(ii) The total number of natural gas driven pneumatic pumps vented directly to the atmosphere at any point during the year.

(iii) [Reserved]

(iv) [Reserved]

(3) For natural gas driven pneumatic pumps for which vented emissions were calculated using Calculation Method 1 according to § 98.233(c)(1), report the information in paragraphs (c)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas driven pneumatic pumps downstream of the flow monitor.

(iv) An indication of whether any natural gas pneumatic devices are also downstream of the monitoring location.

(v) Annual CO_2 emissions, in metric tons CO_2, for the natural gas driven pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the natural gas driven pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(4) If you used Calculation Method 2 according to § 98.233(c)(2) to calculate vented emissions, report the information in paragraphs (c)(4)(i) through (viii) of this section, as applicable.

(i) The number of years used in the current measurement cycle.

(ii) The total number of natural gas driven pneumatic pumps for which emissions were measured or calculated using Calculation Method 2.

(iii) Indicate whether the emissions from the natural gas driven pneumatic pumps at this facility were measured during the reporting year or if the emissions were calculated using equation W–2B to § 98.233.

(iv) If the natural gas driven pneumatic pumps at this facility were measured during the reporting year, indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(v) If the emissions from natural gas driven pneumatic pumps at this facility were calculated using equation W–2B to § 98.233, report the following information:

(A) The value of the emission factor for the reporting year as calculated using equation W–2A to § 98.233 (in scf/hour/pump).

(B) The total number of natural gas driven pneumatic pumps measured across all years upon which the emission factor is based (*i.e.,* the cumulative value of "$\Sigma_{ny=1}$ $Count_y$" term used in equation W–2A to § 98.233).

(C) Total number of natural gas driven pneumatic pumps that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(c)(1) or (c)(2)(iii) (*i.e.,* "Count" in equation W–2B to § 98.233).

(D) The average estimated number of hours in the operating year the pumps were pumping liquid (*i.e.,* "T" in equation W–2B to § 98.233).

(vi) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this facility were measured during the reporting year.

(vii) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this facility were measured during the reporting year.

(viii) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this facility were measured during the reporting year.

(ix) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this facility were measured during the reporting year.

(5) If you used Calculation Method 3 according to § 98.233(c)(3) to calculate vented emissions, report the information in paragraphs (c)(5)(i) through (iv) of this section for the natural gas driven pneumatic pumps subject to Calculation Method 3.

(i) Number of pumps that vent directly to the atmosphere (*i.e.,* ''Count'' in equation W–2B to § 98.233).

(ii) Average estimated number of hours in the calendar year that natural gas driven pneumatic pumps that vented directly to atmosphere were pumping liquid (''T'' in equation W–2B to § 98.233).

(iii) 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)(3).

(iv) 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)(3).

(d) * * *

(2) * * *

(iii) If you used Calculation Method 4 as specified in § 98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (M) of this section, as applicable to the simulation software package used.

* * * * *

(M) If a vent meter is installed and you elected to use Calculation Method 4 for an AGR, report the information in paragraphs (d)(2)(iii)(M)(*1*) through (*3*) of this section.

(*1*) The total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by flow meter (''$V_{a,meter}$'' from equation W–4D to § 98.233).

(*2*) The total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined the standard simulation software package (''$V_{a,sim}$'' from equation W–4D to § 98.233).

(*3*) If the calculated percent difference between the vent volumes (''PD'' from equation W–4D to § 98.233) is greater than 20 percent, provide a brief description of the reason for the difference.

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators for which you calculated emissions using Calculation Method 1 according to § 98.233(e)(1), glycol dehydrators for which you calculated emissions using Calculation Method 2 according to § 98.233(e)(2), and dehydrators that use desiccant. 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 for which you calculated emissions using Calculation Method 1 (as specified in § 98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator.

* * * * *

(2) For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day for which you calculated emissions using Calculation Method 2 (as specified in § 98.233(e)(2)), you must report the information specified in paragraphs (e)(2)(i) through (v) of this section for the entire facility.

(i) The total number of dehydrators at the facility for which you calculated emissions using Calculation Method 2.

* * * * *

(g) * * *

(5) If you used equation W–10A to § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (iv) of this section.

* * * * *

(iv) Whether the flow rate during the initial flowback period was determined using a multiphase flow meter upstream of the separator.

(6) If you used equation W–10B to § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iv) of this section.

* * * * *

(iii) If a multiphase flowmeter was used to measure the flow rate during the initial flowback period, report the average flow rate measured by the multiphase flow meter from the initiation of flowback to the beginning of the period of time when sufficient quantities of gas present to enable separation in standard cubic feet per hour.

* * * * *

(j) * * *

(2) * * *

(i) * * *

(A) The total annual oil/condensate 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 oil/condensate production that send oil/condensate to atmospheric tanks for which emissions were calculated using Calculation Method 3. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual oil/condensate throughput from all wells and the well ID number(s) for the well(s) included in this volume.

* * * * *

(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 to § 98.233). Do not report GOR if you used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.,* if you did not use equation W–18 to § 98.233 for the well with associated gas venting or flaring emissions).

(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of ''$V_{p,q}$'' used in equation W–18 to § 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 used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.,* if you did not use equation W–18 to § 98.233 for the well with associated gas venting or flaring emissions).

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of ''SG'' values used in equation W–18 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation 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 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 used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.,* if you did not use equation W–18 to § 98.233).

(7) * * *

(ii) If the associated gas volume vented from the well was measured using a continuous flow monitor, total volume of associated gas vented directly to the atmosphere, in standard cubic feet.

* * * * *

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(o)(10)(iii) are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

* * * * *

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(p)(10)(iii) are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

* * * * *

(q) * * *

(1) You must report the information specified in paragraphs (q)(1)(i) through (vi) of this section.

* * * * *

(vi) Report whether emissions were calculated using Calculation Method 1 (leaker factor emission calculation methodology) and/or using Calculation Method 2 (leaker measurement methodology).

(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 (ix) of this section separately for component surveys using Calculation Method 1 and Calculation Method 2.

(i) [Reserved]

(ii) Component type.

(iii) [Reserved]

(iv) Emission factor or measurement method used (*e.g.,* default emission factor; facility-specific emission factor developed according to § 98.233(q)(4); or direct measurement according to § 98.233(q)(3)).

(v) Total number of components surveyed by type in the calendar year.

(vi) Total number of the surveyed component type that were identified as leaking in the calendar year (''x_p'' in equation W–30 to § 98.233 for the component type or the number of leaks measured for the specified component type according to the provisions in § 98.233(q)(3)).

(vii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of ''$T_{p,z}$'' from equation W–30 to § 98.233 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))).

(viii) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using equation W–30 to § 98.233 or § 98.233(q)(3)(vii) (for surveyed components only).

(ix) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using equation W–30 to § 98.233 or § 98.233(q)(3)(vii) (for surveyed components only).

* * * * *

■ 17. Revise and republish § 98.236 to 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) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10) of this section, and each applicable emission source listed in paragraphs (b) through (z), (dd) and (ee) of this section.

(1) *Onshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(1)(i) through (xxii) 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.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Liquids unloading.* Report the information specified in paragraph (f) of this section.

(vi) *Completions and workovers with hydraulic fracturing.* Report the information specified in paragraph (g) of this section.

(vii) *Completions and workovers without hydraulic fracturing.* Report the information specified in paragraph (h) of this section.

(viii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(ix) *Hydrocarbon liquids and produced water storage tanks.* Report the information specified in paragraph (j) of this section.

(x) *Well testing.* Report the information specified in paragraph (l) of this section.

(xi) *Associated natural gas.* Report the information specified in paragraph (m) of this section.

(xii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(xiii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(xiv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(xv) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(xvi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xvii) *EOR injection pumps.* Report the information specified in paragraph (w) of this section.

(xviii) *EOR hydrocarbon liquids.* Report the information specified in paragraph (x) of this section.

(xix) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xx) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(xxi) *Drilling mud degassing.* Report the information specified in paragraph (dd) of this section.

(xxii) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(2) *Offshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(2)(i) and (ii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Offshore petroleum and natural gas production.* Report the information specified in paragraph (s) of this section.

(ii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(3) *Onshore natural gas processing.* For the equipment/activities specified in paragraphs (a)(3)(i) through (xi) 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.

(ii) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(iii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iv) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(v) *Hydrocarbon liquids and produced water storage tanks.* Report the information specified in paragraph (j) of this section.

(vi) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(vii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(viii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(ix) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(x) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xi) *Crankcase vents.* Report the information specified in paragraph (ee) of this section.

(4) *Onshore natural gas transmission compression.* For the equipment/activities specified in paragraphs (a)(4)(i) through (x) 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.

(ii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iv) *Condensate storage tanks.* Report the information specified in paragraph (k) of this section.

(v) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(vi) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(viii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(ix) *Other large release events.* Report the information specified in paragraph (y) of this section.

(x) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(5) *Underground natural gas storage.* For the equipment/activities specified in paragraphs (a)(5)(i) through (xi) 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.

(ii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iv) *Condensate storage tanks.* Report the information specified in paragraph (k) of this section.

(v) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(vi) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(viii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(ix) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(x) *Other large release events.* Report the information specified in paragraph (y) of this section.

(xi) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(6) *LNG storage.* For the equipment/activities specified in paragraphs (a)(6)(i) through (ix) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iv) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(v) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vi) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(ix) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(7) *LNG import and export equipment.* For the equipment/activities specified in paragraphs (a)(7)(i) through (ix) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iv) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(v) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vi) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(viii) *Other large release events.* Report the information specified in paragraph (y) of this section.

(ix) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(8) *Natural gas distribution.* For the equipment/activities specified in paragraphs (a)(8)(i) through (vii) 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.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(iv) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(v) *Other large release events.* Report the information specified in paragraph (y) of this section.

(vi) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(vii) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xiv) 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.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units and nitrogen removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(vi) *Hydrocarbon liquids and produced water storage tanks.* Report the information specified in paragraph (j) of this section.

(vii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(viii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(ix) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(x) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(xi) *Equipment leaks by population count.* Report the information specified in paragraph (r) 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.

(xiv) *Crankcase vents.* Reporting the information specified in paragraph (ee) of this section.

(10) *Onshore natural gas transmission pipeline.* For the equipment/activities specified in paragraphs (a)(10)(i) through (iii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(ii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(iii) *Other large release events.* Report the information specified in paragraph (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 (6) of this section, as applicable. You must report the information specified in paragraphs (b)(1) through (6) of this section, as applicable, for each well-pad (for onshore petroleum and natural gas production), each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) The number of natural gas pneumatic devices as specified in paragraphs (b)(2)(i) through (viii) of this section, as applicable. If a natural gas pneumatic device was vented directly to the atmosphere for part of the year and routed to a flare, combustion unit, or vapor recovery system during another part of the year, then include the device in each of the applicable counts specified in paragraphs (b)(2)(ii) through (vii) of this section.

(i) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed), determined according to § 98.233(a)(5) through (7).

(ii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere, determined according to § 98.233(a)(5) through (7).

(iii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) routed to a flare, combustion, or vapor recovery system.

(iv) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1).

(v) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(a)(2).

(vi) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 3 according to § 98.233(a)(3).

(vii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 4 according to § 98.233(a)(4).

(viii) If the reported values in paragraphs (b)(2)(i) through (vii) of this section are estimated values determined according to § 98.233(a)(6), then you must report the information specified in paragraphs (b)(2)(viii)(A) through (C) of this section.

(A) The number of natural gas pneumatic devices of each type reported in paragraphs (b)(2)(i) through (vii) of this section that are counted.

(B) The number of natural gas pneumatic devices of each type reported in paragraphs (b)(2)(i) through (vii) 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.

(3) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1), report the information in paragraphs (b)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) downstream of the flow monitor.

(iv) An indication of whether a natural gas driven pneumatic pump is also downstream of the flow monitor.

(v) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(4) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(a)(2), report the information in paragraphs (b)(4)(i) through (ii) of this section, as applicable.

(i) For onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities:

(A) Indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(B) The average number of hours each type of the natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed) was in service (*i.e.,* supplied with natural gas) in the calendar year.

(C) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(D) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(ii) For onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, and natural gas distribution facilities:

(A) The number of years used in the current measurement cycle.

(B) Indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler) to measure the emissions from natural gas pneumatic devices at this facility.

(C) Indicate whether the emissions from any natural gas pneumatic devices at this facility were calculated using equation W–1B to § 98.233.

(D) If the emissions from any natural gas pneumatic devices at this facility were calculated using equation W–1B to § 98.233, report the following information for each type of natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(*1*) The value of the emission factor for the reporting year as calculated using equation W–1A to § 98.233 (in scf/hour/device).

(*2*) The total number of natural gas pneumatic devices measured across all years upon which the emission factor is based (*i.e.,* the cumulative value of ''$\Sigma y{=}1^{n}$ $Count_{t,y}$'' in equation W–1A to § 98.233).

(*3*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (*i.e.,* ''$Count_t$'' in equation W–1B to § 98.233).

(*4*) The average estimated number of hours in the operating year the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) (''T_t'' in equation W–1B to § 98.233).

(E) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(F) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(G) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this facility were monitored during the reporting year.

(H) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this facility were monitored during the reporting year.

(5) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using

Calculation Method 3 according to § 98.233(a)(3), report the information in paragraphs (b)(5)(i) through (iv) of this section.

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices:

(A) Indicate whether you measured emissions according to § 98.233(a)(3)(i)(A) or used default emission factors according to § 98.233(a)(3)(i)(B) to calculate emissions from your continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere at this well-pad, gathering and boosting site, or facility, as applicable.

(B) If measurements were made according to § 98.233(a)(3)(i)(A), indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(C) If default emission factors were used according to § 98.233(a)(3)(i)(B) to calculate emissions, report the following information for each type of applicable natural gas pneumatic device (continuous low bleed and continuous high bleed).

(*1*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (''$Count_t$'' in equation W–1B to § 98.233).

(*2*) The average estimated number of hours in the operating year that the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) (''T_t'' in equation W–1B to § 98.233).

(ii) For intermittent bleed natural gas pneumatic devices:

(A) Indicate the primary monitoring method used (OGI; Method 21 at 10,000 ppm; Method 21 at 500 ppm; or infrared laser beam) and the number of complete monitoring surveys conducted at the well-pad site or gathering and boosting site.

(B) The total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''x'' in equation W–1C to § 98.233).

(C) Average time the intermittent bleed natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) and assumed to be malfunctioning in the calendar year (average value of ''$T_{m,z}$'' in equation W–1C to § 98.233).

(D) The total number of intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (''Count'' in equation W–1C to § 98.233).

(E) Average time the intermittent bleed natural gas pneumatic 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–1C to § 98.233).

(iii) Annual CO_2 emissions, in metric tons CO_2, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(iv) Annual CH_4 emissions, in metric tons CH_4, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(6) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 4 according to § 98.233(a)(4), report the following information for each type of applicable natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(i) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) (*i.e.,* ''$Count_t$'' in equation W–1B to § 98.233).

(ii) The average estimated number of hours in the operating year that the natural gas pneumatic devices were in service (*i.e.,* supplied with natural gas) (''T_t'' in equation W–1B to § 98.233).

(iii) Annual CO_2 emissions, in metric tons CO_2, for each type of natural gas pneumatic device calculated according to Calculation Method 4 in § 98.233(a)(4).

(iv) Annual CH_4 emissions, in metric tons CH_4, for each type of natural gas pneumatic device calculated according to Calculation Method 4 in § 98.233(a)(4).

(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 (5) of this section. You must report the information specified in paragraphs (c)(1) through (5) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production) and each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) The number of natural gas driven pneumatic pumps as specified in paragraphs (c)(2)(i) through (iv) of this section, as applicable. If a natural gas driven pneumatic 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 device in each of the applicable counts specified in paragraphs (c)(2)(ii) through (iv) of this section.

(i) The total number of natural gas driven pneumatic pumps.

(ii) The total number of natural gas driven pneumatic pumps vented directly to the atmosphere at any point during the year (including pumps that normally routed emissions to a flare but flow bypassed the flare for part of the year).

(iii) The total number of natural gas driven pneumatic pumps routed to a flare at any point during the year.

(iv) The total number of natural gas driven pneumatic pumps routed to combustion or a vapor recovery system at any point during the year.

(3) For natural gas driven pneumatic pumps for which vented emissions were calculated using Calculation Method 1 according to § 98.233(c)(1), report the information in paragraphs (c)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas driven pneumatic pumps downstream of the flow monitor.

(iv) An indication of whether any natural gas pneumatic devices are also downstream of the monitoring location.

(v) Annual CO_2 emissions, in metric tons CO_2, for the pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(4) If you used Calculation Method 2 according to § 98.233(c)(2) to calculate vented emissions, report the information in paragraphs (c)(4)(i) through (ix) of this section, as applicable.

(i) The number of years used in the current measurement cycle.

(ii) The total number of natural gas driven pneumatic pumps for which emissions were measured or calculated using Calculation Method 2.

(iii) Indicate whether the emissions from the natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site, as applicable, were measured during the reporting year or if the emissions were calculated using equation W–2B to § 98.233.

(iv) If the natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site, as applicable, were measured during the reporting year, indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(v) If the emissions from natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site, as applicable, were calculated using equation W–2B to § 98.233, report the following information:

(A) The value of the emission factor for the reporting year as calculated using equation W–2A to § 98.233 (in scf/hour/pump).

(B) The total number of natural gas driven pneumatic pumps measured across all years upon which the emission factor is based (*i.e.*, the cumulative value of ''$\Sigma_{y=1}^{n}$ $Count_y$'' term used in equation W–2A to § 98.233).

(C) Total number of natural gas driven pneumatic pumps that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(c)(1) or (c)(2)(iii) (*i.e.*, ''Count'' in equation W–2B to § 98.233).

(D) The average estimated number of hours in the operating year the pumps were pumping liquid (*i.e.*, ''T'' in equation W–2B to § 98.233).

(vi) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this well-pad or gathering and boosting site were measured during the reporting year.

(vii) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this well-pad or gathering and boosting site were measured during the reporting year.

(viii) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this well-pad or gathering and boosting site were measured during the reporting year.

(ix) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site were measured during the reporting year.

(5) If you used Calculation Method 3 according to § 98.233(c)(3) to calculate vented emissions, report the information in paragraphs (c)(5)(i) through (iv) of this section for the natural gas driven pneumatic pumps subject to Calculation Method 3.

(i) Number of pumps that vent directly to the atmosphere (*i.e.*, ''Count'' in equation W–2B to § 98.233).

(ii) Average estimated number of hours in the calendar year that natural gas driven pneumatic pumps that vented directly to atmosphere were pumping liquid (''T'' in equation W–2B to § 98.233).

(iii) 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)(3).

(iv) 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)(3).

(d) *Acid gas removal units and nitrogen removal units.* You must indicate whether your facility has any acid gas removal units or nitrogen removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. For any acid gas removal units or nitrogen removal units that vent directly to the atmosphere or to a sulfur recovery plant, you must report the information specified in paragraphs (d)(1) and (2) of this section. If the acid gas removal units or nitrogen removal units that vent directly to the atmosphere for only part of the year, report the information specified in paragraph (d)(2) if this section for the part of the year that the units vent directly to the atmosphere. For acid gas removal units or nitrogen removal units that were routed to an engine or routed to a vapor recovery system for the entire year, you must only report the information specified in paragraphs (d)(1)(i) through (v) and (x) of this section. For acid gas removal units or nitrogen removal units that were routed to flares for which you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), you must report the information specified in paragraphs (d)(1)(i) through (v) and (x) of this section, as applicable. For acid gas removal units that were routed to flares for which you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(d) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (d)(1)(i) through (vii) and (x) of this section and paragraph (d)(2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (xi) of this section for each acid gas removal unit or nitrogen removal unit, as applicable.

(i) A unique name or ID number for the acid gas removal unit or nitrogen removal unit. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit or nitrogen removal unit for each location it operates at in a given year.

(ii) Whether the acid gas removal unit or nitrogen removal unit vent was routed to a flare. If so, report the information specified in paragraphs (d)(1)(ii)(A) through (D) of this section for acid gas removal units and the information specified in paragraph (d)(1)(ii)(B) of this section for nitrogen removal units.

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(d) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the acid gas removal unit or nitrogen removal unit vent was routed.

(D) The unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the acid gas removal unit or nitrogen removal unit vent.

(iii) Whether the acid gas removal unit or nitrogen removal unit vent was routed to combustion, and if so, whether it was routed for the entire year or only part of the year.

(iv) Whether the acid gas removal unit or nitrogen removal unit vent was routed to a vapor recovery system, and if so, whether it was routed for the entire year or only part of the year.

(v) Total feed rate entering the acid gas removal unit or nitrogen removal unit, using a meter or engineering estimate based on process knowledge or best available data, in million standard cubic feet per year.

(vi) If the acid gas removal unit or nitrogen removal unit was routed to a flare, to combustion, or to vapor recovery for only part of the year, the feed rate entering the acid gas removal unit or nitrogen removal unit during the portion of the year that the emissions were vented directly to the atmosphere, using a meter or engineering estimate based on process knowledge or best available data, in million standard cubic feet per year.

(vii) The calculation method used to calculate CO_2 and CH_4 emissions from the acid gas removal unit or to calculate CH_4 emissions from the nitrogen removal unit, as specified in § 98.233(d).

(viii) Annual CO_2 emissions, in metric tons CO_2, vented directly to the atmosphere from the acid gas removal unit, calculated using any one of the calculation methods specified in § 98.233(d) and as specified in § 98.233(d)(11) and (12).

(ix) Annual CH_4 emissions, in metric tons CH_4, vented directly to the atmosphere from the acid gas removal unit or nitrogen removal unit, calculated using any one of the calculation methods specified in § 98.233(d) and as specified in § 98.233(d)(11) and (12).

(x) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) You must report information specified in paragraphs (d)(2)(i) through (iii) of this section, applicable to the calculation method reported in paragraph (d)(1)(iii) of this section, for each acid gas removal unit or nitrogen removal unit.

(i) If you used Calculation Method 1 or Calculation Method 2 as specified in § 98.233(d) to calculate CO_2 emissions from the acid gas removal unit and Calculation Method 2 as specified in § 98.233(d) to calculate CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(i)(A) through (C) of this section, as applicable.

(A) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit.

(B) Annual average volumetric fraction of CH_4 in the vent gas exiting the acid gas removal unit or nitrogen removal unit.

(C) Annual volume of gas vented from the acid gas removal unit or nitrogen removal unit, in cubic feet.

(D) The temperature that corresponds to the reported annual volume of gas vented from the unit, in degrees Fahrenheit. If the annual volume of gas vented is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(E) The pressure that corresponds to the reported annual volume of gas vented from the unit, in pounds per square inch absolute. If the annual volume of gas vented is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(ii) If you used Calculation Method 3 as specified in § 98.233(d) to calculate CO_2 or CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(ii)(A) through (M) of this section, as applicable depending on the equation used.

(A) Indicate which equation was used (equation W–4A, W–4B, or W–4C to § 98.233).

(B) Annual average volumetric fraction of CO_2 in the natural gas flowing out of the acid gas removal unit, as specified in equation W–4A, equation W–4B, or equation W–4C to § 98.233.

(C) Annual average volumetric fraction of CO_2 content in natural gas flowing into the acid gas removal unit, as specified in equation W–4A, equation W–4B, or equation W–4C to § 98.233.

(D) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit, as specified in equation W–4A or equation W–4B to § 98.233.

(E) Annual average volumetric fraction of CH_4 in the natural gas flowing out of the acid gas removal unit or nitrogen removal unit, as specified in equation W–4A, equation W–4B, or equation W–4C to § 98.233.

(F) Annual average volumetric fraction of CH_4 content in natural gas flowing into the acid gas removal unit or nitrogen removal unit, as specified in equation W–4A, equation W–4B, or equation W–4C to § 98.233.

(G) Annual average volumetric fraction of CH_4 in the vent gas exiting the acid gas removal unit or nitrogen removal unit, as specified in equation W–4A or equation W–4B to § 98.233.

(H) The total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in equation W–4A or equation W–4C to § 98.233, in cubic feet at actual conditions.

(I) The temperature that corresponds to the reported total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in equation W–4A or equation W–4C to § 98.233, in degrees Fahrenheit. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(J) The pressure that corresponds to the reported total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in equation W–4A or equation W–4C to § 98.233, in pounds per square inch absolute. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(K) The total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in equation W–4B or equation W–4C to § 98.233, in cubic feet at actual conditions.

(L) The temperature that corresponds to the reported total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in equation W–4B or equation W–4C to § 98.233, in degrees Fahrenheit. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(M) The pressure that corresponds to the reported total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in equation W–4B or equation W–4C to § 98.233, in pounds per square inch absolute. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(iii) If you used Calculation Method 4 as specified in § 98.233(d) to calculate CO_2 or CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (O) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Annual average natural gas feed temperature, in degrees Fahrenheit.

(C) Annual average natural gas feed pressure, in pounds per square inch.

(D) Annual average natural gas feed flow rate, in standard cubic feet per minute.

(E) Annual average acid gas content of the feed natural gas, in mole percent.

(F) Annual average acid gas content of the outlet natural gas, in mole percent.

(G) Annual average methane content of the feed natural gas, in mole percent.

(H) Annual average methane content of the outlet natural gas, in mole percent.

(I) Total annual unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(J) Annual average exit temperature of the natural gas, in degrees Fahrenheit.

(K) Annual average solvent pressure, in pounds per square inch.

(L) Annual average solvent temperature, in degrees Fahrenheit.

(M) Annual average solvent circulation rate, in gallons per minute.

(N) Solvent type used for the majority of the year, 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 (specify).

(O) If a vent meter is installed and you elected to use Calculation Method 4 for an AGR, report the information in paragraphs (d)(2)(iii)(O)(*1*) through (*3*) of this section.

(*1*) The total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by flow meter (''$V_{a,meter}$'' from equation W–4D to § 98.233).

(*2*) The total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined the standard simulation software package (''$V_{a,sim}$'' from equation W–4D to § 98.233).

(*3*) If the calculated percent difference between the vent volumes (''PD'' from equation W–4D to § 98.233) is greater than 20 percent, provide a brief description of the reason for the difference.

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators for which you calculated emissions using Calculation Method 1 according to § 98.233(e)(1), glycol dehydrators for which you calculated emissions using Calculation Method 2 according to § 98.233(e)(2), and dehydrators that use desiccant. 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. For dehydrators that were routed to flares for which you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), you must report the information specified in paragraph (e)(4) of this section. For dehydrators that were routed to flares for which you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(e) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the applicable information in paragraphs (e)(1) through (3) of this section and the information specified in paragraph (e)(4) of this section.

(1) For each glycol dehydrator for which you calculated emissions using Calculation Method 1 (as specified in § 98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator. If reported emissions are based on more than one simulation, you must report the average of the simulation inputs.

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

(ii) Dehydrator feed natural gas flow rate, in million standard cubic feet per day.

(iii) Dehydrator feed natural gas water content, in pounds per million standard cubic feet.

(iv) Dehydrator outlet natural gas water content, in pounds per million standard cubic feet.

(v) Dehydrator absorbent circulation pump type (*e.g.*, natural gas pneumatic, air pneumatic, or electric).

(vi) Dehydrator absorbent circulation rate, in gallons per minute.

(vii) Type of absorbent (*e.g.*, triethylene glycol (TEG), diethylene glycol (DEG), or ethylene glycol (EG)).

(viii) Whether stripping gas is used in dehydrator.

(ix) Whether a flash tank separator is used in dehydrator.

(x) Total time the dehydrator is operating during the year, in hours.

(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.

(xiii) Mole fraction of CH_4 in wet natural gas.

(xiv) Mole fraction of CO_2 in wet natural gas.

(xv) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (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 (F) of this section for the emissions from the flash tank vent, as applicable. If flash tank emissions were routed to a regenerator firebox/fire tubes, then you must also report the information specified in paragraphs (e)(1)(xvi)(G) through (I) of this section for the combusted emissions from the flash tank vent.

(A) 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.

(B) 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) and, if applicable, (e)(4).

(C) 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) and, if applicable, paragraph (e)(4) of this section.

(D) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(F) Annual N_2O emissions, in metric tons N_2O, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(G) Indicate whether the regenerator firebox/fire tubes was monitored with a CEMS. If a CEMS was used, then paragraphs (e)(1)(xvi)(E) and (F) and (e)(1)(xvi)(H) and (I) of this section do not apply.

(H) Total volume of gas from the flash tank to a regenerator firebox/fire tubes, in standard cubic feet.

(I) Average combustion efficiency, expressed as a fraction of gas from the flash tank combusted by a burning regenerator firebox/fire tubes.

(xvii) Report the information specified in paragraphs (e)(1)(xvii)(A) through (F) of this section for the emissions from the still vent, as applicable. If still vent emissions were routed to a regenerator firebox/fire tubes, then you must also report the information specified in paragraphs (e)(1)(xvii)(G) through (I) of this section for the combusted emissions from the still vent.

(A) Whether any still vent 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.

(B) 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), and, if applicable, (e)(4).

(C) 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) and, if applicable, (e)(4).

(D) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(F) Annual N_2O emissions, in metric tons N_2O, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(G) Indicate whether the regenerator firebox/fire tubes were monitored with a CEMS. If a CEMS was used, then paragraphs (e)(1)(xvii)(E) and (F) and (e)(1)(xvii)(H) and (I) of this section do not apply.

(H) Total volume of gas from the still vent to a regenerator firebox/fire tubes, in standard cubic feet.

(I) Average combustion efficiency, expressed as a fraction of gas from the still vent combusted by a burning regenerator firebox/fire tubes.

(xviii) Name of the software package used.

(2) You must report the information specified in paragraphs (e)(2)(i) through (vi) 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 for which you calculated emissions using Calculation Method 2 (as specified in § 98.233(e)(2)) at the facility, well-pad site, or gathering and boosting site.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of dehydrators at the facility, well-pad site, or gathering and boosting site for which you calculated emissions using Calculation Method 2.

(iii) 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.

(iv) Whether any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions 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.

(v) 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)(v)(A) through (E) of this section.

(A) The total number of dehydrators routed to a flare and the total number of dehydrators routed to regenerator firebox/fire tubes.

(B) Total volume of gas from the flash tank to a regenerator firebox/fire tubes, in standard cubic feet.

(C) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(D) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(E) Annual N_2O emissions, in metric tons N_2O, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(vi) For dehydrator emissions that were not routed to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(vi)(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)(ii) 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), 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)(ii) 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), where emissions are added together for all such dehydrators.

(3) For dehydrators that use desiccant (as specified in § 98.233(e)(3)), you must report the information specified in paragraphs (e)(3)(i) through (viii) of this section for each well-pad site, gathering and boosting site, or facility, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Count of desiccant dehydrators as specified in paragraphs (e)(3)(ii)(A) and (B) of this section that had one or more openings during the calendar year at the facility, well-pad site, or gathering and boosting site for which you calculated emissions using Calculation Method 3.

(A) The number of opened desiccant dehydrators that used deliquescing desiccant (*e.g.*, calcium chloride or lithium chloride).

(B) The number of opened desiccant dehydrators that used regenerative desiccant (*e.g.*, molecular sieves, activated alumina, or silica gel).

(iii) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, total physical volume of all opened dehydrator vessels.

(iv) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, total number of dehydrator openings in the calendar year.

(v) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, 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.

(vi) For desiccant dehydrators at the facility, well-pad, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, whether any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or a non-flare combustion unit. If any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or a non-flare combustion unit, 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.

(vii) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, whether any dehydrator emissions were routed to a flare or a non-flare combustion unit. If any dehydrator emissions were routed to a flare or a non-flare combustion unit, then you must report the information specified in paragraphs (e)(3)(vii)(A) through (E) of this section.

(A) The total number of dehydrators routed to a flare and the total number of dehydrators routed to a non-flare combustion unit.

(B) Total volume of gas from the flash tank to non-flare combustion units, in standard cubic feet.

(C) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators routed to non-flare combustion units reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(D) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators routed to non-flare combustion units reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(E) Annual N_2O emissions, in metric tons N_2O, for the dehydrators routed to non-flare combustion units reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(viii) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section that were not routed to a flare or a non-flare combustion unit, report the information specified in paragraphs (e)(3)(viii)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(ii) of this section that are not venting to a flare or non-flare combustion units, calculated according to § 98.233(e)(3) and, if applicable, (e)(4), and summing for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(ii) of this section that are not venting to a flare or non-flare combustion unit, calculated according to § 98.233(e)(3), and, if applicable, (e)(4), and summing for all such dehydrators.

(4) For dehydrators that were routed to flares, report the information specified in paragraphs (e)(4)(i) through (iv) of this section.

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(e) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the dehydrator vent was routed.

(iv) The unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the dehydrator.

(f) *Liquids unloading.* You must indicate whether well venting for liquids unloading occurs at your facility, and if so, which methods (as specified in § 98.233(f)) were used to calculate emissions. If your facility performs well venting for liquids unloading venting to the atmosphere and uses Calculation Method 1, then you must report the information specified in paragraph (f)(1) of this section. If the facility performs liquids unloading venting to the atmosphere and uses Calculation Method 2 or 3, then you must report the information specified in paragraph (f)(2) of this section.

(1) For each well for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading vented to the atmosphere, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells with plunger lifts and wells without plunger lifts by unloading type combination (with or without plunger lifts, automated or manual unloading).

(i) Well ID number.

(ii) Well tubing diameter and pressure group ID.

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloading).

(iv) [Reserved]

(v) Indicate whether the monitoring period used to determine the cumulative amount of time venting to the atmosphere was not the full calendar year.

(vi) Cumulative amount of time the well was vented directly to the atmosphere (''T_p'' from equation W–7A or W–7B to § 98.233), in hours.

(vii) Cumulative number of unloadings vented directly to the atmosphere for the well.

(viii) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to § 98.233(f)(1).

(ix) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to § 98.233(f)(1) and (4).

(x) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to § 98.233(f)(1) and (4).

(xi) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xi)(A) through (F) of this section for each individual well not using a plunger lift that was tested during the year.

(A) Well ID number of tested well.

(B) Casing pressure, in pounds per square inch absolute.

(C) Internal casing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(F) Unloading type (automated or manual).

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (F) of this section for each individual well using a plunger lift that was tested during the year.

(A) Well ID number.

(B) The tubing pressure, in pounds per square inch absolute.

(C) The internal tubing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(F) Unloading type (automated or manual).

(2) For each well 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 vented to the atmosphere, 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 (with or without plunger lifts, automated or manual unloadings).

(i) Well ID number.

(ii) Calculation method.

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloadings).

(iv) [Reserved]

(v) Cumulative number of unloadings venting directly to the atmosphere for the well.

(vi) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to § 98.233(f)(2) or (3), as applicable.

(vii) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to § 98.233(f)(2) or (3), as applicable, and § 98.233(f)(4).

(viii) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to § 98.233(f)(2) or (3), as applicable, and § 98.233(f)(4).

(ix) Average flow-line rate of gas (average of ''SFR_p'' from equation W–8 or W–9 to § 98.233, 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 to § 98.233, as applicable), in hours.

(xi) For each well without plunger lifts, the information in paragraphs (f)(2)(xi)(A) through (C) of this section.

(A) Internal casing diameter (''CD_p'' from equation W–8 to § 98.233), in inches.

(B) Well depth (''WD_p'' from equation W–8 to § 98.233), in feet.

(C) Shut-in pressure, surface pressure, or casing pressure (''SP_p'' from equation W–8 to § 98.233), in pounds per square inch absolute.

(xii) For each well with plunger lifts, the information in paragraphs (f)(2)(xiii)(A) through (C) of this section.

(A) Internal tubing diameter (''TD_p'' from equation W–9 to § 98.233), in inches.

(B) Tubing depth (''WD_p'' from equation W–9 to § 98.233), in feet.

(C) Flow line pressure (''SP_p'' from equation W–9 to § 98.233), in pounds per square inch absolute.

(g) *Completions and workovers with hydraulic fracturing.* You must indicate whether your facility had any well completions or workovers with hydraulic fracturing during the calendar year. If your facility had well completions or workovers with hydraulic fracturing during the calendar year that vented directly to the atmosphere, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each well. If your facility had well completions or workovers with hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (g)(1) through (3) and (10) of this section, for each well. If your facility had well completions or workovers with hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(g) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (g)(1) through (6) and (10) of this section, for each well. Report information separately for completions and workovers.

(1) Well ID number.

(2) Well type combination (horizontal or vertical, flared or vented, reduced emission completion or not a reduced emission completion, gas well or oil well).

(3) Number of completions or workovers for each well.

(4) Calculation method used.

(5) If you used equation W–10A to § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (v) of this section.

(i) Cumulative gas flowback time, in hours, for all completions or workovers at the well from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of ''$T_{p,i}$'' and sum of ''$T_{p,s}$'' values used in equation W–10A to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 number of hours of flowback from the well during completions or workovers.

(ii) If the well is a measured well for the sub-basin and well-type combination, the flowback rate, in standard cubic feet per hour (average of ''$FR_{s,p}$'' values used in equation W–12A to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 flowback rate(s) during well completion or workover for the well.

(iii) If you used equation W–12C to § 98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil (''GOR_p'' in equation W–12C to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the gas to oil ratio for the well.

(B) Volume of oil produced during the first 30 days of production after completion of the newly drilled well or well workover using hydraulic fracturing, in barrels (''V_p'' in equation W–12C to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the volume of oil produced during the first 30 days of production after well completion or workover for the well.

(iv) Whether the flow rate during the initial flowback period was determined using:

(A) A recording flow meter (digital or analog) installed on the vent line, downstream of a separator.

(B) A multiphase flow meter upstream of the separator.

(C) Equation W–11A or W–11B to § 98.233.

(v) Whether the flow rate when sufficient quantities are present to enable separation was determined using:

(A) A recording flow meter (digital or analog) installed on the vent line, downstream of a separator.

(B) Equation W–11A or W–11B to § 98.233.

(6) If you used equation W–10B to § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet (''$FV_{s,p}$'' in equation W–10B to § 98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour (''$FR_{p,i}$'' in equation W–10B to § 98.233).

(iii) If a multiphase flowmeter was used to measure the flow rate during the initial flowback period, report the average flow rate measured by the multiphase flow meter from the initiation of flowback to the beginning of the period of time when sufficient quantities of gas present to enable separation in standard cubic feet per hour.

(7) Annual gas emissions, in standard cubic feet (''$E_{s,n}$'' in equation W–10A or W–10B to § 98.233).

(8) Annual CO_2 emissions, in metric tons CO_2.

(9) Annual CH_4 emissions, in metric tons CH_4.

(10) Indicate whether natural gas emissions from completion(s) or workover(s) with hydraulic fracturing were routed to a flare and emissions are reported according to paragraph (n) of this section, and if so, provide the information specified in paragraphs (g)(10)(i) through (iv) of this section.

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(g) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(iv) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(h) *Completions and workovers without hydraulic fracturing.* You must indicate whether the facility had any gas well completions without hydraulic fracturing or any gas well workovers without hydraulic fracturing, and if the activities occurred with or without flaring. If the facility had gas well completions or workovers without hydraulic fracturing, then you must report the information specified in paragraphs (h)(1) through (4) of this section, as applicable.

(1) For each well with one or more gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Well ID number.

(ii) Number of well completions that vented gas directly to the atmosphere without flaring.

(iii) Total number of hours that gas vented directly to the atmosphere during venting for all completions without hydraulic fracturing (''T_p'' for completions that vented directly to the atmosphere as used in equation W–13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 number of hours that gas vented directly to the atmosphere during completions for the well.

(iv) Average daily gas production rate for all completions without hydraulic fracturing without flaring, in standard cubic feet per hour (''V_p'' in equation W–13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 average daily gas production rate during completions for the well.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions venting gas directly to the atmosphere (''$E_{s,p}$'' from equation W–13B to § 98.233 for completions that vented directly to the atmosphere, converted to mass emissions according to § 98.233(h)(1)).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions venting gas directly to the atmosphere (''$E_{s,p}$'' from equation W–13B to § 98.233 for completions that vented directly to the atmosphere, converted to mass emissions according to § 98.233(h)(1)).

(2) If your facility had well completions without hydraulic fracturing and with flaring during the year and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (h)(2)(i) through (ii) and (viii) of this section, for each well. If your facility had well completions without hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (h)(2)(i) through (iv) and (viii) of this section, for each well.

(i) Well ID number.

(ii) Number of well completions that flared gas.

(iii) Total number of hours that gas routed to a flare during venting for all completions without hydraulic fracturing (''T_p'' for completions that vented to a flare from equation W–13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 number of hours that gas vented to the flare during completions for the well.

(iv) Average daily gas production rate for all completions without hydraulic fracturing with flaring, in standard cubic feet per hour (''V_p'' from equation W–13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 average daily gas production rate during completions for the well.

(v) [Reserved]

(vi) [Reserved]

(vii) [Reserved]

(viii) Report the information specified in paragraphs (h)(2)(viii)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(3) For each well with one or more gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Well ID number.

(ii) Number of workovers that vented gas to the atmosphere without flaring.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers venting gas directly to the atmosphere (''$E_{s,wo}$'' in equation W–13A to § 98.233 for workovers that vented directly to the atmosphere, converted to mass emissions as specified in § 98.233(h)(1)).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers venting gas directly to the atmosphere (''$E_{s,wo}$'' in equation W–13A to § 98.233 for workovers that vented directly to the atmosphere, converted to mass emissions as specified in § 98.233(h)(1)).

(4) If your facility had well workovers without hydraulic fracturing and with flaring during the year and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (h)(4)(i) through (ii) and (vi) of this section, for each well. If your facility had well workovers without hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (h)(4)(i) through (ii) and (vi) of this section, for each well.

(i) Well ID number.

(ii) Number of workovers that flared gas.

(iii) [Reserved]

(iv) [Reserved]

(v) [Reserved]

(vi) Report the information specified in paragraphs (h)(4)(vi)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section. You must report the information specified in paragraphs (i)(1) through (3) of this section, as applicable, for each well-pad site (for onshore production), each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(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)(A) for onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, or onshore petroleum and natural gas gathering and boosting industry segments, then you must report the information specified in paragraphs (i)(1)(i) through (v) of this section, as applicable. If a blowdown event resulted in emissions from multiple equipment or event types, and the emissions cannot be apportioned to the different equipment or event types, then you may report the information in paragraphs (i)(1)(ii) through (v) of this section for the equipment or event type that represented the largest portion of the emissions for the blowdown event. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, if a blowdown event is not directly associated with a specific well-pad site or gathering and boosting site (*e.g.*, a mid-field pipeline blowdown) or could be associated with multiple well-pad or gathering and boosting sites, then you may report the information in paragraphs (i)(1)(i) through (v) of this section for either the nearest well-pad site or gathering and boosting site upstream from the blowdown event or the well-pad site or gathering and boosting site that represented the largest portion of the emissions for the blowdown event, as appropriate. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2)(iv)(B) for the natural gas distribution or onshore natural gas transmission pipeline industry segments, then you must report the information specified in paragraphs (i)(1)(ii) through (v) of this section, as applicable. If a blowdown event resulted in emissions from multiple equipment or event types, and the emissions cannot be apportioned to the different equipment or event types, then you may report the information in paragraphs (i)(1)(ii) through (v) of this section for the equipment or event type that represented the largest portion of the emissions for the blowdown event.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Equipment or event type. For the onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, or onshore petroleum and natural gas gathering and boosting industry segments, use the seven categories listed in § 98.233(i)(2)(iv)(A). For the natural gas distribution or onshore natural gas transmission pipeline industry segments, use the eight categories listed in § 98.233(i)(2)(iv)(B).

(iii) Total number of blowdowns in the calendar year for the equipment or event type (the sum of equation variable ''N'' from equation W–14A or equation W–14B to § 98.233, for all unique physical volumes for the equipment or event type).

(iv) Annual CO_2 emissions for the equipment or event type, in metric tons CO_2, calculated according to § 98.233(i)(2)(iii).

(v) Annual CH_4 emissions for the equipment or event type, in metric tons CH_4, calculated according to § 98.233(i)(2)(iii).

(2) *Report by flow meter.* If you elect to calculate emissions from blowdown vent stacks by using a flow meter according to § 98.233(i)(3), then you

must report the information specified in paragraphs (i)(2)(i) through (iii) of this section, as applicable. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, if a blowdown event is not directly associated with a specific well-pad site or gathering and boosting site (*e.g.*, a mid-field pipeline blowdown) or could be associated with multiple well-pad sites or gathering and boosting sites, then you may report the information in paragraphs (i)(2)(i) through (iii) of this section for either the nearest well-pad site or gathering and boosting site upstream from the blowdown event or the well-pad site or gathering and boosting site that represented the largest portion of the emissions for the blowdown event, as appropriate.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Annual CO_2 emissions from all blowdown vent stacks at the facility, well-pad site, or gathering and boosting site for which emissions were calculated using flow meters, in metric tons CO_2 (the sum of all CO_2 mass emission values calculated according to § 98.233(i)(3), for all flow meters).

(iii) Annual CH_4 emissions from all blowdown vent stacks at the facility, well-pad site, or gathering and boosting site for which emissions were calculated using flow meters, in metric tons CH_4, (the sum of all CH_4 mass emission values calculated according to § 98.233(i)(3), for all flow meters).

(3) *Onshore natural gas transmission pipeline segment.* Report the information in paragraphs (i)(3)(i) through (iii) of this section for each state.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) Annual number of blowdown events.

(j) *Hydrocarbon liquids and produced water storage tanks.* You must indicate whether your facility sends hydrocarbon produced liquids and/or produced water to atmospheric pressure storage tanks. If your facility sends hydrocarbon produced liquids and/or produced water to atmospheric pressure storage 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 pressure storage 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. For hydrocarbon liquids and produced water storage tanks that were routed to flares for which you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), you must report the information specified in paragraph (j)(4) of this section. For hydrocarbon liquids and produced water storage tanks that were routed to flares for which you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(j) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the applicable information in paragraphs (j)(1) through (3) of this section and the information specified in paragraph (j)(4) 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 well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) and by calculation method and liquid type, as applicable. Onshore petroleum and natural gas gathering and boosting and onshore natural gas processing facilities do not report the information specified in paragraph (j)(1)(ix) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual hydrocarbon liquids or produced water volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable atmospheric pressure 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/or delineation wells are the only wells at the well-pad site with hydrocarbon liquids or produced water production flowing to gas-liquid separators or direct to atmospheric pressure storage tanks for which you used the same calculation method. 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 or produced water from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average well, gas-liquid separator, or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average well, gas-liquid separator, or non-separator equipment pressure, in pounds per square inch gauge.

(vi) For atmospheric pressure storage tanks receiving hydrocarbon liquids, the average sales oil or stabilized hydrocarbon liquids API gravity, in degrees.

(vii) If you used Calculation Method 1 of § 98.233(j) to calculate GHG emissions for atmospheric pressure storage tanks receiving hydrocarbon liquids, the flow-weighted average concentration (mole fraction) of CO_2 in flash gas from atmospheric pressure 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 total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks).

(viii) If you used Calculation Method 1 of § 98.233(j) to calculate GHG emissions for atmospheric pressure storage tanks receiving hydrocarbon liquids, the flow-weighted average concentration (mole fraction) of CH_4 in flash gas from atmospheric pressure 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 total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks).

(ix) The number of wells sending hydrocarbon liquids or produced water to gas-liquid separators or directly to atmospheric pressure storage tanks.

(x) Count of atmospheric pressure storage tanks specified in paragraphs (j)(1)(x)(A) through (F) of this section.

(A) The number of fixed roof atmospheric pressure storage tanks.

(B) The number of floating roof atmospheric pressure storage tanks.

(C) The number of atmospheric pressure storage 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.

(D) The number of atmospheric pressure storage tanks that routed emissions to a vapor recovery system at any point during the reporting year.

(E) The number of atmospheric pressure storage tanks that routed emissions to one or more flares at any point during the reporting year.

(F) The number of atmospheric pressure storage tanks in paragraph (j)(1)(x)(D) or (E) of this section that had an open or not properly seated thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(xi) For atmospheric pressure storage tanks receiving hydrocarbon liquids, 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).

(xii) 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).

(xiii) For the atmospheric pressure storage tanks receiving hydrocarbon liquids identified in paragraphs (j)(1)(x)(D) of this section, total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(xiv) For the atmospheric pressure storage tanks identified in paragraphs (j)(1)(x)(D) of this section, total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(xv) For the atmospheric pressure storage tanks identified in paragraph (j)(1)(x)(F) of this section, the total volume of gas vented through open thief hatches, in scf, during periods while the storage 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 (H) of this section, at the facility level, for atmospheric pressure storage 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 pressure storage tanks in the facility with emissions calculated using Calculation Method 3, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells at the facility with hydrocarbon liquids production that send hydrocarbon liquids to atmospheric pressure storage tanks for which emissions were calculated using Calculation Method 3. 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 annual hydrocarbon liquids throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) The total annual produced water throughput that is sent to all atmospheric pressure storage tanks in the facility with emissions calculated using Calculation Method 3, in barrels, specified in paragraphs (j)(2)(i)(B)(*1*) through (*3*) of this section.

(*1*) Total volume of produced water with pressure less than or equal to 50 psi.

(*2*) Total volume of produced water with pressure greater than 50 psi and less than or equal to 250 psi.

(*3*) Total volume of produced water with pressure greater than 250 psi.

(C) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with flares.

(D) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with vapor recovery systems.

(E) An estimate of the fraction of total produced water throughput reported in paragraph (j)(2)(i)(B) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with flares.

(F) An estimate of the fraction of total produced water throughput reported in paragraph (j)(2)(i)(B) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with vapor recovery systems.

(G) The number of fixed roof atmospheric pressure storage tanks in the facility.

(H) The number of floating roof atmospheric pressure storage tanks in the facility.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (H) of this section for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) with atmospheric pressure storage tanks receiving hydrocarbon liquids whose emissions were calculated using § 98.233(j)(3)(i).

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) The number of atmospheric pressure storage tanks that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) The number of atmospheric pressure storage tanks that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(D) The number of atmospheric pressure storage tanks that had an open thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(E) The total number of separators, wells, or non-separator equipment with annual average daily hydrocarbon liquids throughput greater than 0 barrels per day and less than 10 barrels per day for which you used Calculation Method 3 (''Count'' from equation W–15A to § 98.233).

(F) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated using equation W–15A to § 98.233 and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(G) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated using equation W–15A to § 98.233 and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(H) The total volume of gas vented through open thief hatches, in scf, during periods while the atmospheric pressure storage tanks were also routing emissions to vapor recovery systems and/or flares.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (F) of this section for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for onshore natural gas processing) with atmospheric pressure storage tanks receiving produced water whose emissions were calculated using § 98.233(j)(3)(ii).

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) The number of atmospheric pressure storage tanks that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) The number of atmospheric pressure storage tanks that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(D) The number of atmospheric pressure storage tanks that had an open thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated using equation W–15B to § 98.233 and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(F) The total volume of gas vented through open thief hatches, in scf, during periods while the atmospheric pressure storage tanks were also routing emissions to vapor recovery systems and/or flares.

(3) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (v) of this section for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) by liquid type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(iii) 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 to § 98.233).

(iv) For atmospheric pressure storage tanks receiving hydrocarbon liquids, annual CO_2 emissions, in metric tons CO_2, that resulted from dump valves on gas-liquid separators not closing properly during the calendar year, calculated using equation W–16 to § 98.233.

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from the dump valves on gas-liquid separators not closing properly during the calendar year, calculated using equation W–16 to § 98.233.

(4) For atmospheric pressure storage tanks that were routed to flares, report the information specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(j) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the atmospheric pressure storage tank vent was routed.

(iv) The unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the atmospheric pressure storage tank.

(k) *Condensate storage tanks.* You must indicate whether your facility contains any condensate storage tanks. If your facility contains at least one condensate storage tank, then you must report the information specified in paragraphs (k)(1) and (2) of this section for each condensate storage tank vent stack.

(1) For each condensate storage tank vent stack, report the information specified in (k)(1)(i) through (iv) of this section.

(i) The unique name or ID number for the condensate storage tank vent stack.

(ii) Indicate if a flare is attached to the condensate storage tank vent stack.

(iii) Indicate whether scrubber dump valve leakage occurred for the condensate storage tank vent according to § 98.233(k)(1).

(iv) Which method specified in § 98.233(k)(1) was used to determine if dump valve leakage occurred.

(2) If scrubber dump valve leakage occurred for a condensate storage tank vent stack, as reported in paragraph (k)(1)(iii) 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 condensate storage vent stack where scrubber dump valve leakage occurred.

(i) Which method specified in § 98.233(k)(2) was used to measure the leak rate.

(ii) Measured leak rate (average leak rate from a continuous flow measurement device), in standard cubic feet per hour.

(iii) Duration of time that the leak is counted as having occurred, in hours, as determined in § 98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(k)(1) through (4).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(k)(1) through (4).

(l) *Well testing.* You must indicate whether you performed gas well or oil well testing, and if the testing of gas wells or oil wells resulted in vented or flared emissions during the calendar year. If you performed well testing that resulted in vented or flared emissions during the calendar year, then you must report the information specified in paragraphs (l)(1) through (4) of this section, as applicable.

(1) For oil wells not routed to a flare, you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section for each well tested.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year.

(iv) Average gas to oil ratio for the tested well, in cubic feet of gas per barrel of oil. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average gas to oil ratio for the tested well.

(v) Average flow rate for the tested well, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 average flow rate for the tested well.

(vi) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(vii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(2) For oil wells routed to a flare and where you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (l)(2)(i) through (ii) and (ix) of this section, for each well tested. For oil wells routed to a flare and where you calculated natural gas emissions routed

to the flare using the calculation methods in § 98.233(l) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (l)(2)(i) through (v) and (ix) of this section. All reported data elements should be specific to the well for which equation W–17A to § 98.233 was used and for which well testing emissions were routed to flares.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year.

(iv) Average gas to oil ratio for the tested well, in cubic feet of gas per barrel of oil. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average gas to oil ratio for the tested well.

(v) Average flow rate for the tested well, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 average flow rate for the tested well.

(vi) [Reserved]

(vii)[Reserved]

(viii) [Reserved]

(ix) Indicate whether natural gas emissions from well testing were routed to a flare and emissions are reported according to paragraph (n) of this section, and if so, provide the information specified in paragraphs (l)(2)(ix)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(l) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(3) For gas wells not routed to a flare, you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section for each well tested.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well(s) in the calendar year. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the number of well testing days for the tested well.

(iv) Average annual production rate for the tested well, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 average annual production rate for the tested well.

(v) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(vi) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(4) For gas wells routed to a flare and where you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (l)(4)(i) through (ii) and (viii) of this section, for each well tested. For gas wells routed to a flare and where you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(l) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (l)(4)(i) through (iv) and (viii) of this section for each well tested. All reported data elements should be specific to the well for which equation W–17B to § 98.233 was used and for which well testing emissions were routed to flares.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the number of well testing days for the tested well.

(iv) Average annual production rate for the tested well, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well and/or delineation well and the only wells that are tested in the same basin are wildcat wells and/or delineation wells. 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 average annual production rate for the tested well.

(v) [Reserved]

(vi)[Reserved]

(vii) [Reserved]

(viii) Indicate whether natural gas emissions from well testing were routed to a flare and emissions are reported according to paragraph (n) of this section, and if so, provide the information specified in paragraphs (l)(4)(viii)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(l) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(m) *Associated natural gas.* You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented during the calendar year, then you must report the information specified in paragraphs (m)(1) through (7) of this section for each well for which associated gas was vented. If associated gas was flared during the calendar year and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (m)(1) through (3) of this section, for each well. If associated gas was flared and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(m) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (m)(1) through (6) of this section for each well.

(1) Well ID number.

(2) Indicate whether any associated gas was vented directly to the atmosphere without flaring.

(3) Indicate whether any associated gas was flared and emissions are reported according to paragraph (n) of this section, and, if so, provide the information specified in paragraphs (m)(3)(i) through (iv).

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(m) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack to which associated natural gas is routed as specified in paragraph (n)(1) of this section.

(iv) The unique ID for each associated natural gas stream routed to the flare as specified in paragraph (n)(3) of this section.

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil during the reporting year. 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 (*i.e.*, if you did not use equation W–18 to § 98.233 for the well with associated gas venting or flaring emissions).

(5) Volume of oil produced by the well, in barrels, in the calendar year only during the time periods in which associated gas was vented or flared (''V_p'' used in equation W–18 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the volume of oil produced by the well during the time periods in which associated gas venting and flaring was occurring. 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 (*i.e.*, if you did not use equation W–18 to § 98.233 for the well with associated gas venting or flaring emissions).

(6) Total volume of associated gas sent to sales or used on site and not sent to a vent or flare, in standard cubic feet, in the calendar year only during time periods in which associated gas was vented or flared (''SG'' value used in equation W–18 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 the well during the time periods in which associated gas venting and flaring was occurring. 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 (*i.e.*, if you did not use equation W–18 to § 98.233).

(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 well.

(i) [Reserved]

(ii) Indicate whether the associated gas volume vented from the well was measured using a continuous flow monitor.

(iii) Indicate whether associated gas streams vented from the well were measured with continuous gas composition analyzers.

(iv) Total volume of associated gas vented from the well, in standard cubic feet.

(v) Flow-weighted average mole fraction of CH_4 in associated gas vented from the well.

(vi) Flow-weighted average mole fraction of CO_2 in associated gas vented from the well.

(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).

(n) *Flare stacks.* You must indicate if your facility has any flare stacks. You must report the information specified in paragraphs (n)(1) through (20) of this section for each flare stack at your facility.

(1) 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.

(2) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(3) Unique IDs for each stream routed to the flare and the source type that generated the stream, if you determine the flow of each stream that is routed to the flare as specified in § 98.233(n)(3)(ii) and/or you determine the gas composition for each stream routed to the flare as specified in § 98.233(n)(4)(iii). If you determine flow or composition for a combined stream from multiple source types, then report the source type that provides the most gas to the combined stream. For source types not listed in § 98.233(n)(3)(ii)(B)(*1*) through (*7*), report collectively as ''other.''

(4) Indicate the type of flare (*i.e.*, open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare).

(5) 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).

(6) Indicate whether the pilot flame or combustion flame was monitored continuously, visually inspected, or both. If visually inspected, report the number of inspections during the year. If the pilot flame was monitored continuously, report the number of times all continuous monitoring devices were out of service or otherwise inoperable for a period of more than one week.

(7) Indicate whether you measured total flow at the inlet to the flare as specified in § 98.233(n)(3)(i) or whether you determined flow for individual streams routed to the flare as specified in § 98.233(n)(3)(ii). If you measured total flow, indicate whether the volume of gas was determined using a continuous flow measurement device or whether it was determined using parameter monitoring and engineering calculations. If you determined flow for individual streams, indicate for each stream whether flow was determined using a continuous flow measurement device, parameter monitoring and engineering calculations, or other simulation or engineering calculation methods. If you switched from one method to another during the year, then indicate multiple methods were used.

(8) Indicate whether a continuous gas composition analyzer was used at the inlet to the flare as specified in

§ 98.233(n)(4)(i), whether composition at the inlet to the flare was determined based on sampling and analysis as specified in § 98.233(n)(4)(ii), or if composition was determined for individual streams as specified in § 98.233(n)(4)(iii). If you determined composition for individual streams, indicate for each stream whether composition was determined using a continuous gas composition analyzer, sampling and analysis, or other simulation or engineering calculation methods. If you switched from one method to another during the year, then indicate multiple methods were used.

(9) Indicate whether you directly measured annual average HHV of the inlet stream to the flare as specified in § 98.233(n)(8)(i), calculated the annual average HHV of the inlet stream to the flare based on composition of the inlet stream as specified in § 98.233(n)(8)(ii), directly measured the annual average HHV of individual streams routed to the flare as specified in § 98.233(n)(8)(iii), or calculated the annual average HHV of individual streams based on their composition as specified in § 98.233(n)(8)(iv).

(10) Annual average HHV of the inlet stream to the flare determined as specified in § 98.233(n)(8)(i) or (ii); both the calculated flow-weighted annual average HHV of the inlet stream to the flare and each individual stream HHV determined as specified in § 98.233(n)(8)(iii)(B) or (iv)(B); or each individual stream HHV, if you determined HHVs for each individual stream routed to the flare and you used these HHVs to calculate N_2O emissions for each stream as specified in § 98.233(n)(8)(iii)(A) or (iv)(A).

(11) Volume of gas sent to the flare, in standard cubic feet (''V_s'' in equations W–19 and W–20 to § 98.233, where V_s is the total flow at the flare inlet if you measure inlet flow to the flare in accordance with § 98.233(n)(3)(i) or the sum of the V_s values for individual streams if you measure or determine flow of individual streams in accordance with § 98.233(n)(3)(ii)). If you measure or determine the volume of gas for each stream routed to the flare as specified in § 98.233(n)(3)(ii), then also report the annual volume of each stream, adjusted to exclude any estimated volume that bypassed the flare or determined to have leaked from the closed vent system, and indicate that the flow has been adjusted to account for bypass volume or leaks.

(12) Fraction of the feed gas sent to an un-lit flare based on total time when continuous monitoring of the pilot or periodic inspections indicated the flare was not lit and measured or calculated flow during the times when the flare was not lit (''Z_U'' in equation W–19 to § 98.233).

(13) Flare destruction efficiency, expressed as the fraction of hydrocarbon compounds in gas that is destroyed by a burning flare, but may or may not be completely oxidized to CO_2 (§ 98.233(n)(1)). If you used multiple methods during the year, report the flow-weighted average destruction efficiency based on each tier that applied. Report the efficiency fraction to three decimal places.

(i) If you use tier 1, report the following:

(A) Number of days in periods of 15 or more consecutive days when you did not conform with all cited provisions in § 98.233(n)(1)(i).

(B) [Reserved]

(ii) If you use tier 2, report the following:

(A) Indicate if you are 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 or if you are electing to comply with the flare 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.

(B) If you are not required to comply with part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, indicate whether you are electing to comply with § 98.233(n)(1)(ii)(A), (B), (C), or (D).

(C) If you are not required to comply with part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and the flare is an enclosed ground level flare or an enclosed elevated flare, indicate if your most recent performance test was conducted using the method in § 60.5413b(b) of this chapter (as specified in § 98.233(n)(1)(ii)(A)), the method in § 60.5413b(d) of this chapter (as specified in § 98.233(n)(1)(ii)(C)), or if it was conducted using OTM–52.

(D) Number of days in periods of 15 or more consecutive days when you did not conform with all cited provisions in § 98.233(n)(1)(ii).

(iii) Indicate if you use an alternative test method approved under § 60.5412b(d) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If you use an approved alternative test method, indicate the approved destruction efficiency for the method, the date when you started to use the method, and the name or ID of the method.

(14) Annual average mole fraction of CH_4 in the feed gas to the flare if you measure composition of the inlet gas as specified in § 98.233(n)(3)(i) or (ii) (''X_{CH4}'' in equation W–19 to § 98.233), or the annual average CH_4 mole fractions for each stream if you determine composition of each stream routed to the flare as specified in § 98.233(n)(4)(iii).

(15) Except as specified in paragraph (n)(20) of this section, annual average mole fraction of CO_2 in the feed gas to the flare if you measure composition of the inlet gas as specified in § 98.233(n)(4)(i) or (ii) (''X_{CO2}'' in equation W–20 to § 98.233), or the annual average CO_2 mole fractions for each stream if you determine composition of each stream routed to the flare as specified in § 98.233(n)(4)(iii).

(16) Annual CO_2 emissions, in metric tons CO_2 (refer to equation W–20 to § 98.233).

(17) Annual CH_4 emissions, in metric tons CH_4 (refer to equation W–19 to § 98.233).

(18) Annual N_2O emissions, in metric tons N_2O (refer to equation W–40 to § 98.233).

(19) Estimated disaggregated CH_4, CO_2, and N_2O emissions attributed to each source type as determined in § 98.233(n)(10) (*i.e.*, AGR vents, dehydrator vents, well venting during completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, hydrocarbon liquids and produced water storage tanks, well testing venting and flaring, associated gas venting and flaring, other flared sources).

(20) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used, then you are not required to report the CO_2 mole fraction in paragraph (n)(15) of this section.

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(o)(10)(iii) are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (o)(1)(i) through (xi) of this section, as applicable, for each centrifugal compressor located at your facility.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Unique name or ID for the centrifugal compressor.

(iii) Hours in operating-mode.

(iv) Hours in standby-pressurized-mode.

(v) Hours in not-operating-depressurized-mode.

(vi) 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.

(vii) Indicate whether the compressor has blind flanges installed and associated dates.

(viii) Indicate whether the compressor has wet or dry seals.

(ix) If the compressor has wet seals, the number of wet seals.

(x) If the compressor has dry seals, the number of dry seals.

(xi) Power output of the compressor driver (hp).

(2) *Compressor source.* (i) For each compressor source at each compressor, report the information specified in paragraphs (o)(2)(i)(A) through (C) of this section.

(A) Centrifugal compressor name or ID. Use the same ID as in paragraph (o)(1)(ii) of this section.

(B) Centrifugal compressor source (wet seal, dry seal, isolation valve, or blowdown valve).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (o)(2)(ii)(A) through (E) of this section.

(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 system.

(B) Indicate whether an as found measurement(s) as identified in § 98.233(o)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in § 98.233(o)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (o)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery system, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery system, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) *As found measurement sample data.* If the measurement methods specified in § 98.233(o)(2) or (4) are conducted, report the information specified in paragraph (o)(3)(i) of this section. If the calculation specified in § 98.233(o)(6)(ii) is performed, report the information specified in paragraph (o)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (o)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in equation W–23 to § 98.233 was used to calculate emissions in equation W–22 to § 98.233, report the information specified in paragraphs (o)(3)(ii)(A) through (D) of this section.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in equation W–23 to § 98.233).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in equation W–23 to § 98.233).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in § 98.233(o)(3) or (5) are conducted, report the information specified in paragraphs (o)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in § 98.233(o)(3)(ii) and (o)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions

according to § 98.233(o)(10)(iii) must report the information specified in paragraphs (o)(5)(i) through (iv) of this section. You must report the information specified in paragraphs (o)(5)(i) through (iv) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production) or each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) 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 systems).

(iii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(iv) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(p)(10)(iii) are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (p)(1)(i) through (viii) of this section, as applicable, for each reciprocating compressor located at your facility.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Unique name or ID for the reciprocating compressor.

(iii) Hours in operating-mode.

(iv) Hours in standby-pressurized-mode.

(v) Hours in not-operating-depressurized-mode.

(vi) 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.

(vii) Indicate whether the compressor has blind flanges installed and associated dates.

(viii) Power output of the compressor driver (hp).

(2) *Compressor source.* (i) For each compressor source at each compressor, report the information specified in paragraphs (p)(2)(i)(A) through (C) of this section.

(A) Reciprocating compressor name or ID. Use the same ID as in paragraph (p)(1)(i) of this section.

(B) Reciprocating compressor source (isolation valve, blowdown valve, or rod packing).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (p)(2)(ii)(A) through (E) of this section.

(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 system.

(B) Indicate whether an as found measurement(s) as identified in § 98.233(p)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in § 98.233(p)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (p)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery system, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to a flare, combustion, or vapor recovery system, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) *As found measurement sample data.* If the measurement methods specified in § 98.233(p)(2) or (4) are conducted, report the information specified in paragraph (p)(3)(i) of this section. If the calculation specified in § 98.233(p)(6)(ii) is performed, report the information specified in paragraph (p)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (p)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in equation W–28 to § 98.233 was used to calculate emissions in equation W–27 to § 98.233, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in equation W–28 to § 98.233).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in equation W–28 to § 98.233).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in § 98.233(p)(3) or (5) are conducted, report the information specified in paragraphs (p)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in § 98.233(p)(3)(ii) and (p)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting that calculate emissions according to § 98.233(p)(10)(iii) must report the information specified in paragraphs (p)(5)(i) through (iv) of this section. You must report the information specified in paragraphs (p)(5)(i) through (iv) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production) or each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) 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 directly 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 systems).

(iii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors with rod packing emissions vented directly to the atmosphere.

(iv) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors with rod packing emissions vented directly to the atmosphere.

(q) *Equipment leak surveys.* For any components subject to or complying with the requirements of § 98.233(q), you must report the information specified in paragraphs (q)(1) and (2) of this section. You must report the information specified in paragraphs (q)(1) and (2) of this section, as applicable, for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments). Natural gas distribution facilities with emission sources listed in § 98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) through (ix) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Except as specified in paragraph (q)(1)(iii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(iii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(iv) Except for natural gas distribution facilities and onshore natural gas transmission pipeline 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)(iv)(A) through (E) of this section. Report the indication per well-pad site, gathering and boosting site, or facility, not per component type, as applicable.

(A) The well site or compressor station fugitive emissions standards in § 60.5397a of this chapter.

(B) The well site, centralized production facility, or compressor station fugitive emissions standards in § 60.5397b or § 60.5398b of this chapter.

(C) The well site, centralized production facility, 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 processing plants in § 60.5400b or § 60.5401b of this chapter.

(E) The standards for equipment leaks at onshore natural gas processing plants in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(v) For facilities in onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment, indicate whether you elected to comply with § 98.233(q) according to § 98.233(q)(1)(iv) for any equipment components at your well-pad site, gathering and boosting site, or facility.

(vi) Report each type of method described in § 98.234(a) that was used to conduct leak surveys.

(vii) Report whether emissions were calculated using Calculation Method 1 (leaker factor emission calculation methodology) and/or using Calculation Method 2 (leaker measurement methodology).

(viii) 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–1 to this subpart) by service type for which leak detection surveys were conducted and emissions calculated according to § 98.233(q).

(ix) 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–1 to this subpart) in vacuum service as defined in § 98.238.

(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), (j)(10), (m)(3)(ii) or (m)(4)(ii) for your facility's industry segment. For each component type and leak detection method combination that is located at your well-pad site, gathering and boosting site, or facility, you must report the information specified in paragraphs (q)(2)(i) through (ix) of this section. If a component type is located at your well-pad site, gathering and boosting site, or facility

and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (ix) of this section but report a zero (''0'') for the information required according to paragraphs (q)(2)(vi) through (ix) 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 (ix) of this section separately for component surveys using Calculation Method 1 and Calculation Method 2.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Component type.

(iii) Leak detection method used for the screening survey (*e.g.*, Method 21 as specified in § 98.234(a)(2)(i); Method 21 as specified in § 98.234(a)(2)(ii); and OGI and other leak detection methods as specified in § 98.234(a)(1), (3), or (5)).

(iv) Emission factor or measurement method used (*e.g.*, default emission factor; site-specific emission factor developed according to § 98.233(q)(4); or direct measurement according to § 98.233(q)(3)).

(v) Total number of components surveyed by type and leak detection method in the calendar year.

(vi) Total number of the surveyed component types by leak detection method that were identified as leaking in the calendar year (''xp'' in equation W–30 to § 98.233 for the component type or the number of leaks measured for the specified component type according to the provisions in § 98.233(q)(3)).

(vii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of ''$T_{p,z}$'' from equation W–30 to § 98.233 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)).

(viii) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using equation W–30 to § 98.233 or § 98.233(q)(3)(vii) (for surveyed components only).

(ix) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using equation W–30 to § 98.233 or § 98.233(q)(3)(vii) (for surveyed components only).

(3) Natural gas distribution facilities with emission sources listed in § 98.232(i)(1) must also report the information specified in paragraphs (q)(3)(i) through (viii) and, if applicable, (q)(3)(ix) of this section.

(i) Number of above grade transmission-distribution transfer stations surveyed in the calendar year.

(ii) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in the calendar year (''$Count_{MR,y}$'' from equation W–31 to § 98.233, for the current calendar year).

(iii) Average time that meter/regulator runs surveyed in the calendar year were operational, in hours (average of ''$T_{w,y}$'' from equation W–31 to § 98.233, for the current calendar year).

(iv) Number of above grade transmission-distribution transfer stations surveyed in the current leak survey cycle.

(v) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in current leak survey cycle (sum of ''$Count_{MR,y}$'' from equation W–31 to § 98.233, for all calendar years in the current leak survey cycle).

(vi) Average time that meter/regulator runs surveyed in the current leak survey cycle were operational, in hours (average of ''$T_{w,y}$'' from equation W–31 to § 98.233, for all years included in the leak survey cycle).

(vii) Meter/regulator run CO_2 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CO_2 per operational hour of all meter/regulator runs (''$EF_{s,MR,i}$'' for CO_2 calculated using equation W–31 to § 98.233).

(viii) Meter/regulator run CH_4 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CH_4 per operational hour of all meter/regulator runs (''$EF_{s,MR,i}$'' for CH_4 calculated using equation W–31 to § 98.233).

(ix) If your natural gas distribution facility performs equipment leak surveys across a multiple year leak survey cycle, you must also report:

(A) The total number of meter/regulator runs at above grade transmission-distribution transfer stations at your facility (''$Count_{MR}$'' in equation W–32B to § 98.233).

(B) Average estimated time that each meter/regulator run at above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run (''$T_{w,avg}$'' in equation W–32B to § 98.233).

(C) Annual CO_2 emissions, in metric tons CO_2, for all above grade transmission-distribution transfer stations at your facility.

(D) Annual CH_4 emissions, in metric tons CH_4, for all above grade transmission-distribution transfer stations at your facility.

(r) *Equipment leaks by population count.* If your facility is subject to the requirements of § 98.233(r), then you must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable. You must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) You must indicate whether your facility contains any of the emission source types required to use equation W–32A to § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (vi) of this section separately for each emission source type required to use equation W–32A to § 98.233 that is located at your facility. For each well-pad site and gathering and boosting site at onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, you must report the information specified in paragraphs (r)(1)(i) through (vi) of this section separately by equipment type and service type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) 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.

(iii) Total number of the emission source type at the well-pad site, gathering and boosting site, or facility, as applicable (''$Count_e$'' in equation W–32A to § 98.233).

(iv) Average estimated time that the emission source type was operational in the calendar year, in hours (''T_e'' in equation W–32A to § 98.233).

(v) Annual CO_2 emissions, in metric tons CO_2, for the emission source type.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the emission source type.

(2) Natural gas distribution facilities must also report the information specified in paragraphs (r)(2)(i) through (v) of this section.

(i) Number of above grade transmission-distribution transfer stations at the facility.

(ii) Number of above grade metering-regulating stations that are not transmission-distribution transfer stations at the facility.

(iii) Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations (''$Count_{MR}$'' in equation W–32B to § 98.233).

(iv) Average estimated time that each meter/regulator run at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run (''$T_{w,avg}$'' in equation W–32B to § 98.233).

(v) If your facility has above grade metering-regulating stations that are not above grade transmission-distribution transfer stations and your facility also has above grade transmission-distribution transfer stations, you must also report:

(A) Annual CO_2 emissions, in metric tons CO_2, from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(B) Annual CH_4 emissions, in metric tons CH_4, from above grade metering regulating stations that are not above grade transmission-distribution transfer stations.

(3) You must indicate whether your facility contains any emission source types in vacuum service as defined in § 98.238. If your facility contains equipment in vacuum service, you must report the information specified in paragraphs (r)(3)(i) through (iii) of this section separately for each emission source type in vacuum service that is located at your well-pad site, gathering and boosting site, or facility, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Emission source type.

(iii) Total number of the emission source type at the well-pad site, gathering and boosting site, or facility, as applicable.

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for your facility.

(1) The BOEM Facility ID(s) that correspond(s) to your facility, if applicable.

(2) If you adjusted emissions according to § 98.233(s)(1)(ii) or (s)(2)(ii), report the information specified in paragraphs (s)(2)(i) and (ii) of this section.

(i) Facility operating hours for the year of the most recent emissions calculated according to § 98.233(s)(1)(ii) or § 98.233(s)(2)(ii) prior to the current reporting year.

(ii) Facility operating hours for the current reporting year.

(3) For each emission source type listed in the most recent monitoring and calculation methods published by BOEM as referenced in 30 CFR 550.302 through 304, report the information specified in paragraphs (s)(3)(i) through (iii) of this section.

(i) Annual CO_2 emissions, in metric tons CO_2.

(ii) Annual CH_4 emissions, in metric tons CH_4.

(iii) Annual N_2O emissions, in metric tons N_2O.

(t) [Reserved]

(u) [Reserved]

(v) [Reserved]

(w) *EOR injection pumps.* You must indicate whether CO_2 EOR injection was used at your facility during the calendar year and if any EOR injection pump blowdowns occurred during the year. If any EOR injection pump blowdowns occurred during the calendar year, then you must report the information specified in paragraphs (w)(1) through (8) of this section for each EOR injection pump system.

(1) Sub-basin ID.

(2) EOR injection pump system identifier.

(3) Pump capacity, in barrels per day.

(4) Total volume of EOR injection pump system equipment chambers, in cubic feet (''Vv'' in equation W–37 to § 98.233).

(5) Number of blowdowns for the EOR injection pump system in the calendar year.

(6) Density of critical phase EOR injection gas, in kilograms per cubic foot (''Rc'' in equation W–37 to § 98.233).

(7) Mass fraction of CO_2 in critical phase EOR injection gas (''GHG_{CO2}'' in equation W–37 to § 98.233).

(8) Annual CO_2 emissions, in metric tons CO_2, from EOR injection pump system blowdowns.

(x) *EOR hydrocarbon liquids.* You must indicate whether hydrocarbon liquids were produced through EOR operations. If hydrocarbon liquids were produced through EOR operations, you must report the information specified in paragraphs (x)(1) through (4) of this section for each sub-basin category with EOR operations.

(1) Sub-basin ID.

(2) Total volume of hydrocarbon liquids produced through EOR operations in the calendar year, in barrels (''V_{hl}'' in equation W–38 to § 98.233).

(3) Average CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel under standard conditions (''S_{hl}'' in equation W–38 to § 98.233).

(4) Annual CO_2 emissions, in metric tons CO_2, from CO_2 retained in hydrocarbon liquids produced through EOR operations downstream of the storage tank (''$MassCO_2$'' in equation W–38 to § 98.233).

(y) *Other large release events.* You must indicate whether there were any other large release events from your facility during the reporting year and indicate whether your facility was notified of a potential super-emitter release under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. 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 (10) of this section. If you received a super-emitter release notification under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter that the EPA has not determined to contain a demonstrable error according to the provisions in § 98.233(y)(6), you must include the emissions from that source or event within your subpart W report unless you can provide certification that the facility does not own or operate the equipment at the location identified in the notification using the methods specified in § 98.233(y)(6). Regardless, if you received a super-emitter release notification under the provisions of §§ 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) Unique release event identification number (*e.g.*, Event 1, Event 2).

(3) The latitude and longitude of the release in decimal degrees to at least

four digits to the right of the decimal point.

(4) The approximate start date, start time, and duration (in hours) of the release event, and an indication of how the start date and time were determined (determined based on pressure monitor, temperature monitor, other monitored process parameter (specify), assigned based on last monitoring or measurement survey showing no large release (specify monitoring or measurement survey method), or used the 91-day default start date).

(5) 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: maintenance event, fire/explosion, gas well blowout, oil well blowout, gas well release, oil well release, pressure relief, large leak, and other (specify).

(iii) An indication of whether the release exceeded a threshold in § 98.233(y)(1)(i) or in § 98.233(y)(1)(ii).

(iv) A description of the technology or method used to identify the release.

(v) An indication of whether the release was identified under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and, if the release was identified under the provisions of §§ 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, a unique notification ID number for the notification as assigned in paragraph (y)(11)(i) of this section.

(vi) 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 and the assumed combustion efficiency for the combusted natural gas.

(6) The total volume of gas released during the event in standard cubic feet.

(7) The volume fraction of CO_2 in the gas released during the event.

(8) The volume fraction of CH_4 in the gas released during the event.

(9) Annual CO_2 emissions, in metric tons CO_2, from the release event that occurred during the reporting year.

(10) Annual CH_4 emissions, in metric tons CH_4, from the release event that occurred during the reporting year and the maximum CH_4 emissions rate, in kilograms per hour, determined for any period of the event according to the provisions § 98.233(y)(2)(i).

(11) Report the total number of super-emitter release notifications received from the EPA under the provisions of §§ 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for this facility for events that occurred during the reporting year that were not determined by the EPA to have a demonstratable error in the notification and, for each such super-emitter release notification, report the information specified in paragraphs (y)(11)(i) through (v) of this section.

(i) Unique notification identification number (e.g., Notification_01, Notification_02). If a unique notification number was provided with a notification received under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter, an applicable approved state plan, or applicable Federal plan in part 62 of this chapter, report the number associated with the event provided in the notification.

(ii) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only) to which the notification was attributed.

(iii) Based on any assessment or investigation triggered by the notification, indicate if the emissions were from normal operations, a planned maintenance event, leaking equipment, malfunctioning equipment or device, or undetermined cause.

(iv) An indication of whether the emissions identified via the notification are included in annual emissions reported under this subpart and, if so, the source type under which the emissions identified via the notification are reported (from the list of source types required to be reported as specified in § 98.232 for the facility's applicable industry segment). If the emissions were reported following the requirements of § 98.233(y) as an other large release event, report the unique release event identification number assigned to the other large release event as reported in paragraph (y)(2) of this section. If the emissions identified via the notification are not included in the annual emissions reported under this subpart, you must provide certification that the facility does not own or operate the equipment at the location identified in the notification as specified in § 98.233(y)(6)(i) or provide certification that the facility conducted a complete investigation of the site as specified in § 98.233(y)(6)(ii) and does not own or operate the emitting equipment at the location identified in the notification.

(v) Provide an indication if you received a super-emitter release notification from the EPA after December 31 of the reporting year for which investigations are on-going such that the annual report that has been submitted may be revised and resubmitted pending the outcome of the super-emitter investigation.

(z) *Combustion equipment.* 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)(xx), (a)(8)(vi), or (a)(9)(xiii) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xx), (a)(8)(vi), 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. You must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour; or, internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 mmBtu/hr (or the equivalent of 130 horsepower). If the facility contains external fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour or internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 million Btu per hour (or the equivalent of 130 horsepower), then you must report the information specified in paragraphs (z)(1)(i) through (iii) of this section for each unit type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The type of combustion unit.

(iii) The total number of combustion units.

(2) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130

horsepower); or, internal fuel combustion units of any heat capacity that are compressor-drivers. For each type of combustion unit at your facility, you must report the information specified in paragraphs (z)(2)(i) through (iv) and (z)(2)(viii) through (x) of this section, except for internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower) or internal fuel combustion units of any heat capacity that are compressor-drivers that combust natural gas meeting the criteria in § 98.233(z), which must report the information specified in paragraphs (z)(2)(i) through (x) of this section. Information must be reported for each combustion unit type, fuel type, and method for determining the CH_4 emission factor combination, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The type of combustion unit including external fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or internal fuel combustion units of any heat capacity that are compressor-drivers.

(iii) The type of fuel combusted.

(iv) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(v) The equipment type, including reciprocating 2-stroke-lean burn, reciprocating 4-stroke lean-burn, reciprocating 4-stroke rich-burn, and gas turbine.

(vi) The method used to determine the methane emission factor, including the default emission factor from table W–7 to this subpart, OEM data, or performance tests in § 98.234(i) for natural gas described in § 98.233(z)(1) or (2), or performance tests in § 98.234(i) or default combustion efficiency for fuels described in section § 98.233(z)(3).

(vii) The value of the CH_4 emission factor (kg CH_4/mmBtu). If multiple performance tests were performed in the same reporting year, the arithmetic average value of CH_4 emission factor (kg CH_4/mmBtu). This information is not required if CH_4 emissions were calculated per § 98.233(z)(3)(ii)(D).

(viii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(z)(1) through (3).

(ix) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) through (3).

(x) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) through (3).

(aa) *Industry segment-specific information.* Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, determined using a flow meter that meets the requirements of § 98.234(b) for quantities that are sent to sale or through the facility and determined by using best available data for other quantities. If a quantity required to be reported is zero, you must report zero as the value.

(1) For onshore petroleum and natural gas production, report the data specified in paragraphs (aa)(1)(i) and (iv) of this section.

(i) Report the information specified in paragraphs (aa)(1)(i)(A) through (C) of this section for the basin as a whole, unless otherwise specified.

(A) The quantity of gas produced in the calendar year from wells, in thousand standard cubic feet. This includes gas that is routed to a pipeline, vented or flared, or used in field operations. This does not include gas injected back into reservoirs or shrinkage resulting from lease condensate production.

(B) The quantity of natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet.

(C) The quantity of crude oil and condensate produced from producing wells that is sent to sale in the calendar year, in barrels.

(ii) Report the information specified in paragraphs (aa)(1)(ii)(A) through (M) of this section for each unique sub-basin category.

(A) State.

(B) County.

(C) Formation type.

(D) The number of producing wells at the end of the calendar year (exclude only those wells permanently shut-in and plugged).

(E) The number of producing wells acquired during the calendar year.

(F) The number of producing wells divested during the calendar year.

(G) The number of wells completed during the calendar year.

(H) The number of wells permanently shut-in and plugged during the calendar year.

(I) Average mole fraction of CH_4 in produced gas.

(J) Average mole fraction of CO_2 in produced gas.

(K) If an oil sub-basin, report the average GOR of all wells, in thousand standard cubic feet per barrel.

(L) If an oil sub-basin, report the average API gravity of all wells.

(M) If an oil sub-basin, report average low pressure separator pressure, in pounds per square inch gauge.

(iii) Report the information specified in paragraphs (aa)(1)(iii)(A) through (D) of this section for each well located in the facility.

(A) Well ID number.

(B) Well-pad ID.

(C) For each well permanently shut-in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.

(D) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil and condensate produced that is sent to sale in the calendar year, in barrels.

(iv) Report the information specified in paragraphs (aa)(1)(iv)(A) through (C) of this section for each well-pad site located in the facility.

(A) A unique name or ID number for the well-pad.

(B) Sub-basin ID.

(C) The latitude and longitude of the well-pad representing the geographic centroid or center point of the well-pad in decimal degrees to at least four digits to the right of the decimal point.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) through (iv) of this section.

(i) The quantity of natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet.

(ii) The quantity of crude oil and condensate produced from producing wells that is sent to sale in the calendar year, in barrels.

(iii) For each well permanently shut-in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.

(iv) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil and condensate produced that is sent to sale in the calendar year, in barrels.

(3) For natural gas processing, if your facility fractionates NGLs and also reported 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 (ix) of this section. Otherwise, report the information specified in paragraphs (aa)(3)(i) through (ix) 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.

(ii) The quantity of processed (residue) gas leaving the gas processing plant in the calendar year, in thousand standard cubic feet.

(iii) The cumulative quantity of all NGLs (bulk and fractionated) received at the gas processing plant in the calendar year, in barrels.

(iv) The cumulative quantity of all NGLs (bulk and fractionated) leaving the gas processing plant in the calendar year, in barrels.

(v) Average mole fraction of CH_4 in natural gas received.

(vi) Average mole fraction of CO_2 in natural gas received.

(vii) Indicate whether the facility fractionates NGLs.

(viii) Indicate whether the facility reported as a supplier to subpart NN of this part under the same e-GGRT identification number in the calendar year.

(ix) The quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sales without being processed by the facility.

(4) For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.

(i) The quantity of natural gas transported through the compressor station in the calendar year, in thousand standard cubic feet.

(ii) Number of compressors.

(iii) Total compressor power rating of all compressors combined, in horsepower.

(iv) Average upstream pipeline pressure, in pounds per square inch gauge.

(v) Average downstream pipeline pressure, in pounds per square inch gauge.

(5) For underground natural gas storage, report the quantities specified in paragraphs (aa)(5)(i) through (iii) of this section.

(i) The quantity of gas injected into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of natural gas withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(6) For LNG import equipment, report the quantity of LNG imported that is sent to sale in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported that is sent to sale in the calendar year, in thousand standard cubic feet.

(8) For LNG storage, report the quantities specified in paragraphs (aa)(8)(i) through (iii) of this section.

(i) The quantity of LNG added into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of LNG withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(9) [Reserved]

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (v) of this section.

(i) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(ii) The quantity of natural gas transported from the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels.

(iv) The quantity of all hydrocarbon liquids transported from the gathering and boosting facility in the calendar year, in barrels.

(v) Report the information specified in paragraphs (aa)(10)(v)(A) through (E) of this section for each gathering and boosting site located in the facility for which there were emissions in the calendar year.

(A) A unique name or ID number for the gathering and boosting site.

(B) Gathering and boosting site type (gathering compressor station, centralized oil production site, gathering pipeline, or other fence-line site).

(C) State.

(D) For gathering compressor stations, centralized oil production sites, and other fence-line sites, county.

(E) For gathering compressor stations, centralized oil production sites, and other fence-line sites, the latitude and longitude of the gathering and boosting site representing the geographic centroid or center point of the site in decimal degrees to at least four digits to the right of the decimal point.

(11) For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(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.

(iv) The quantity of natural gas transported through the facility and transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

(v) The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.

(vi) The miles of transmission pipeline for each state in the facility.

(bb) *Missing data.* 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.

(1) For quarterly measurements, report the total number of quarters that a missing data procedure was used for each data element rather than the total number of hours.

(2) For annual or biannual (once every two years) measurements, you do not need to report the number of hours that a missing data procedure was used for each data element.

(cc) *Delay in reporting for wildcat wells and delineation wells.* 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), (m)(5) or (6), (dd)(1)(iii), (dd)(1)(vi)(A), (B), or (C), (dd)(3)(iii)(A), or (dd)(3)(iii)(D)(*1*), (*2*), or (*3*) 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.

(dd) *Drilling mud degassing.* You must indicate whether there were mud degassing operations at your facility, and if so, which methods (as specified in § 98.233(dd)) were used to calculate emissions. For wells for which your facility performed mud degassing operations and used Calculation Method 1, then you must report the information specified in paragraph (dd)(1) of this section. For wells for which your facility performed mud degassing operations and used Calculation Method

2, then you must report the information specified in paragraph (dd)(2) of this section. For wells for which your facility performed mud degassing operations and used Calculation Method 3, then you must report the information specified in paragraph (dd)(3) of this section.

(1) For each well for which you used Calculation Method 1 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(1)(i) through (viii) of this section.

(i) Well ID number.

(ii) Approximate total depth below surface, in feet.

(iii) Target hydrocarbon-bearing stratigraphic formation to which the well is drilled.

(iv) Total time that drilling mud is circulated in the well (T_r in equation W–41 to § 98.233 and T_p in equation W–43 to § 98.233), in minutes, beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore. You may delay reporting of this data element for a representative well if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42 to § 98.233) is applied is a wildcat well or delineation well. You may delay reporting of this data element for any well if you indicate in the annual report that the well is a wildcat or delineation well. 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 time that drilling mud is circulated in the well, in minutes.

(v) The composition of the drilling mud: water-based, oil-based, or synthetic.

(vi) If the well is not a representative well, Well ID number of the representative well used to derive the CH_4 emission rate used to calculate CH_4 emissions for this well.

(vii) If the well is a representative well, report the information specified in paragraphs (dd)(1)(vi)(A) through (D) of this section.

(A) Average mud rate (MR_r in equation W–41 to § 98.233), in gallons per minute. You may delay reporting of this data element if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42 to § 98.233) is applied is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average mud rate, in gallons per minute.

(B) Average concentration of natural gas in the drilling mud (X_n in equation W–41 to § 98.233), in parts per million. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average concentration of natural gas in the drilling mud in parts per million.

(C) Measured mole fraction for CH_4 in natural gas entrained in the drilling mud (GHG_{CH4} in equation W–41 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 mole fraction for CH_4 in natural gas entrained in the drilling mud.

(D) Calculated CH_4 emissions rate in standard cubic feet per minute ($ER_{s,CH4,r}$ in equation W–42 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42 to § 98.233) is applied is a wildcat or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the calculated CH_4 emissions rate in standard cubic feet per minute.

(viii) Annual CH_4 emissions, in metric tons CH_4, from well drilling mud degassing, calculated according to § 98.233(dd)(1).

(2) For each well for which you used Calculation Method 2 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(2)(i) through (iv) of this section.

(i) Well ID number.

(ii) Total number of drilling days (DD_p in equation W–44 to § 98.233).

(iii) The composition of the drilling mud: water-based, oil-based, or synthetic.

(iv) Annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated according to § 98.233(dd)(2).

(3) For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(3)(i) through (iv) of this section.

(i) Well ID number.

(ii) For the time periods you used Calculation Method 1 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(3)(ii)(A) through (G) of this section.

(A) Approximate total depth below surface, in feet.

(B) Target hydrocarbon-bearing stratigraphic formation to which the well is drilled.

(C) Total time that drilling mud is circulated in the well (T_r in equation W–41 to § 98.233 and T_p in equation W–43 to § 98.233), in minutes, beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore. You may delay reporting of this data element for a representative well if you indicate in the annual report that that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42 to § 98.233) is applied is a wildcat well or delineation well. You may delay reporting of this data element for any well if you indicate in the annual report that the well is a wildcat well or delineation well. 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 time that drilling mud is circulated in the well, in minutes.

(D) The composition of the drilling mud: water-based, oil-based, or synthetic.

(E) If the well is not a representative well, Well ID number of the representative well used to derive the CH_4 emission rate used to calculate CH_4 emissions for this well.

(F) If the well is a representative well, report the information specified in paragraphs (dd)(3)(ii)(F)(*1*) through (*4*) of this section.

(*1*) Average mud rate (MR_r in equation W–41 to § 98.233), in gallons per minute. You may delay reporting of this data element if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42 to § 98.233) is applied is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average mud rate, in gallons per minute.

(*2*) Average concentration of natural gas in the drilling mud (X_n in equation W–41 to § 98.233), in parts per million. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average concentration of natural gas in the drilling mud in parts per million.

(*3*) Measured mole fraction for CH_4 in natural gas entrained in the drilling mud (GHG_{CH4} in equation W–41 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. 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 mole fraction for CH_4 in natural gas entrained in the drilling mud.

(*4*) Calculated CH_4 emissions rate in standard cubic feet per minute ($ER_{s,CH4,r}$ in equation W–42 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W–42 to § 98.233) is applied is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the calculated CH_4 emissions rate in standard cubic feet per minute.

(G) Annual CH_4 emissions, in metric tons CH_4, from well drilling mud degassing, calculated according to § 98.233(dd)(1).

(iii) For the time periods for each well for which you used Calculation Method 2 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(3)(iii)(A) through (C) of this section.

(A) Total number of drilling days (DD_p in equation W–44 to § 98.233).

(B) The composition of the drilling mud: water-based, oil-based, or synthetic.

(C) Annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated according to § 98.233(dd)(2).

(iv) Total annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated from summing the annual CH_4 emissions calculated from § 98.233(dd)(3)(iii)(E) and § 98.233(dd)(3)(iv)(C).

(ee) *Crankcase vents.* You must indicate whether your facility performs any crankcase venting from reciprocating internal combustion engines. For all reciprocating internal combustion engines with crankcase vents, you must report the information specified in paragraph (ee)(1) of this section for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments). For each reciprocating internal combustion engine that you conduct measurements as specified in § 98.233(ee)(1), you must report the information specified in paragraph (ee)(2) of this section. For reciprocating internal combustion engines with CH_4 emissions calculated as specified in § 98.233(ee)(2), you must report the information specified in paragraph (ee)(3) of this section for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) The information and number of reciprocating internal combustion engines with crankcase vents as specified in paragraphs (ee)(1)(i) through (v) of this section, as applicable. If a reciprocating internal combustion engine with crankcase vents was vented directly to the atmosphere for part of the year and routed to a flare during another part of the year, then include the engine in each of the applicable counts specified in paragraphs (ee)(1)(iii) and (iv) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of reciprocating internal combustion engines with crankcase vents.

(iii) The total number of reciprocating internal combustion engines with crankcase vents that operated and were vented directly to the atmosphere.

(iv) The total number of reciprocating internal combustion engines with crankcase vents that operated and were routed to a flare.

(v) The total number of reciprocating internal combustion engines with crankcase vents that were in a manifolded group containing a compressor vent source with emissions reported under paragraph (o) or (p) of this section.

(2) Reciprocating internal combustion engines with crankcase vents that calculate emissions according to § 98.233(ee)(1) must report the information specified in paragraphs (ee)(2)(i) and (ii) of this section, as applicable.

(i) For each measurement performed on a crankcase vent, report the information specified in paragraphs (ee)(2)(i)(A) through (F) of this section.

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) Unique name or ID for the reciprocating internal combustion engine.

(C) Measurement date.

(D) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(E) Measured flow rate, in standard cubic feet per hour.

(F) If the measurement is for a manifolded group of crankcase vent sources, indicate the number of reciprocating internal compressor engines that were operating during measurement.

(ii) Annual CH_4 emissions from the reciprocating internal combustion engine crankcase vent, in metric tons CH_4.

(3) Reciprocating internal combustion engines with crankcase vents that calculate emissions according to § 98.233(ee)(2) must report the information specified in paragraphs (ee)(3)(i) through (iv) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Total number of reciprocating internal combustion engines with crankcase vents that were operational at some point in the calendar year at the well-pad site, gathering and boosting site, or facility, as applicable.

(iii) Total time that the reciprocating internal combustion engines with crankcase venting were operational in the calendar year, in hours (''T'' in equation W–46 to § 98.233).

(iv) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(ee)(2).

■ 18. Amend § 98.237 by adding paragraph (g) to read as follows:

§ 98.237 Records that must be retained.

* * * * *

(g) For each situation when you fail to fully conform with all cited provisions in either § 98.233(n)(1)(i) or (ii) for a period of 15 consecutive days and you utilized the Tier 3 default destruction and combustion efficiency values, you must document these periods when the non-conformance began, and the date when full conformance was re-established.

■ 19. Effective July 15, 2024, amend § 98.238 by adding definitions

''Centralized oil production site,'' ''Gathering and boosting site,'' ''Gathering compressor station,'' ''Gathering pipeline site,'' and ''Well-pad site'' in alphabetical order to 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. A *centralized oil production site* is a type of gathering and boosting site for purposes of this subpart.

* * * * *

Gathering and boosting site means a single gathering compressor station as defined in this section, centralized oil production site as defined in this section, gathering pipeline site as defined in this section, or other fence-line site within the onshore petroleum and natural gas gathering and boosting industry segment.

* * * * *

Gathering 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. A *gathering compressor station* is a type of gathering and boosting site for purposes of this subpart.

Gathering pipeline site means all of the gathering pipelines within a single state. A *gathering pipeline site* is a type of gathering and boosting site for purposes of this subpart.

* * * * *

Well-pad site means all equipment on or associated with a single well-pad. Specifically, the well-pad site includes all equipment on a single well-pad plus all equipment associated with that single well-pad.

* * * * *

■ 20. Amend § 98.238 by:

■ a. Removing the definition ''Acid gas removal vent emissions'' a;

■ b. Adding definitions ''Acid gas removal unit (AGR) vent emissions,'' ''Atmospheric pressure storage tank,'' and ''Automated liquids unloading'' in alphabetical order;

■ c. Revising the definitions ''Compressor mode'' and ''Compressor source;''

■ d. Adding definitions ''Crankcase venting,'' ''Drilling mud,'' ''Drilling mud degassing,'' ''Enclosed combustion device,'' and ''Equivalent stratigraphic interval'' in alphabetical order;

■ e. Removing the second definition ''Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements'';

■ f. Revising the definitions ''Flare stack emissions'' and ''Forced extraction of natural gas liquids'';

■ g. Revising the definitions ''Gathering and boosting system'' and ''Gathering and boosting system owner or operator''; and

■ h. Adding definitions ''In vacuum service,'' ''Manual liquids unloading,'' ''Mud rate,'' ''Nitrogen removal unit (NRU),'' ''Nitrogen removal unit vent emissions,'' ''Other large release event,'' ''Produced water,'' ''Routed to combustion,'' ''Target hydrocarbon-bearing stratigraphic formation,'' ''Transmission company interconnect M&R station,'' ''Well blowout,'' and ''Well release'' in alphabetical order.

The additions and revisions read as follows:

§ 98.238 Definitions.

* * * * *

Acid gas removal unit (AGR) vent emissions mean the acid gas separated from the acid gas absorbing medium (*e.g.*, an amine solution) and released with methane and other light hydrocarbons to the atmosphere.

* * * * *

Atmospheric pressure storage tank means a vessel (excluding sumps) operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (*e.g.*, wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof.

Automated liquids unloading means an unloading that is performed without manual interference. Examples of automated liquids unloadings include a timing and/or pressure device used to optimize intermittent shut-in of the well before liquids choke off gas flow or to open and close valves, continually operating equipment that does not require presence of an operator such as rod pumping units, automated and unmanned plunger lifts, or other unloading activities that do not entail a physical presence at the well-pad,

* * * * *

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.

* * * * *

Crankcase venting means the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine. This does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process (*e.g.*, closed crankcase ventilation system, closed breather system) or if the vent blow-by is routed to another closed vent system.

* * * * *

Drilling mud means a mixture of clays and additives with water, oil, or synthetic materials. While drilling, the drilling mud is continuously pumped through the drill string and out the bit to cool and lubricate the drill bit, and move cuttings through the wellbore to the surface.

Drilling mud degassing means the practice of safely removing pockets of free gas entrained in the drilling mud once it is outside of the wellbore.

* * * * *

Enclosed combustion device means a flare that uses a closed flame.

* * * * *

Equivalent stratigraphic interval means the depth of the same stratum of rock in the Earth's subsurface.

* * * * *

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 in and of itself 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.

* * * * *

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production or one or more other gathering and boosting systems and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells or one or more other gathering and boosting systems to a downstream endpoint, typically a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

* * * * *

In vacuum service means equipment operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

* * * * *

Manual liquids unloading means an unloading when field personnel attend to the well at the well-pad, for example to manually plunge a well at the site using a rig or other method, to open a valve to direct flow to an atmospheric tank to clear the well, or to manually shut-in the well to allow pressure to build in the well-bore. Manual unloadings may be performed on a routine schedule or on ''as needed'' basis.

* * * * *

Mud rate means the pumping rate of the mud by the mud pumps, usually measured in gallons per minute (gpm).

* * * * *

Nitrogen removal unit (NRU) means a process unit that separates nitrogen from natural gas using various separation processes (*e.g.*, cryogenic units, membrane units).

Nitrogen removal unit vent emissions means the nitrogen gas separated from the natural gas and released with methane and other gases to the atmosphere.

* * * * *

Other large release event means any planned or unplanned 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 other than under § 98.233(y) 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 hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, 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(a) through (h), (j) through (s), (w), (x), (dd), or (ee) by the threshold in § 98.233(y)(1)(ii). *Other large release events* do not include blowdowns for which emissions are calculated according to the provisions in § 98.233(i).

* * * * *

Produced water means the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

* * * * *

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).

* * * * *

Target hydrocarbon-bearing stratigraphic formation means the stratigraphic interval intended to be the primary hydrocarbon producing formation.

* * * * *

Transmission company interconnect M&R station means a metering and pressure regulating stations with an inlet pressure above 100 psig located at a point of transmission pipeline to transmission pipeline interconnect.

* * * * *

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.

* * * * *

■ 21. Remove tables W–1A, W–1B, W–1C, W–1D, and W–1E to subpart W of part 98 and add table W–1 to subpart W of part 98 in numerical order to read as follows:

TABLE W–1 TO SUBPART W OF PART 98—DEFAULT WHOLE GAS POPULATION EMISSION FACTORS

Industry segment	Source type/component	Emission factor (scf whole gas/hour/unit)
Population Emission Factors—Pneumatic Device Vents and Pneumatic Pumps, Gas Service [1]		
• Onshore petroleum and natural gas production	Continuous Low Bleed Pneumatic Device Vents [2]	6.8
• Onshore petroleum and natural gas gathering and boosting	Continuous High Bleed Pneumatic Device Vents [2]	21
	Intermittent Bleed Pneumatic Device Vents [2]	8.8
	Pneumatic Pumps [3]	13.3
• Onshore natural gas processing	Continuous Low Bleed Pneumatic Device Vents [2]	6.8
• Onshore natural gas transmission compression	Continuous High Bleed Pneumatic Device Vents [2]	30
• Underground natural gas storage	Intermittent Bleed Pneumatic Device Vents [2]	2.3
• Natural gas distribution		
Population Emission Factors—Major Equipment, Gas Service [1]		
• Onshore petroleum and natural gas production	Wellhead	8.87
• Onshore petroleum and natural gas gathering and boosting	Separator	9.65
	Meters/Piping	7.04
	Compressor	13.8
	Dehydrator	8.09
	Heater	5.22
	Storage Vessel	1.83
Population Emission Factors—Major Equipment, Crude Service		
Onshore petroleum and natural gas production	Wellhead	4.13
	Separator	4.77
	Meters/Piping	12.4
	Compressor	13.8
	Dehydrator	8.09
	Heater	3.2
	Storage Vessel	1.91
Population Emission Factors—Gathering Pipelines, by Material Type [4]		
Onshore petroleum and natural gas gathering and boosting	Protected Steel	0.93
	Unprotected Steel	8.2
	Plastic/Composite	0.28
	Cast Iron	8.4

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] Emission factor is in units of "scf whole gas/hour/device."
[3] Emission factor is in units of "scf whole gas/hour/pump."
[4] Emission factors are in units of "scf whole gas/hour/mile of pipeline."

■ 22. Revise table W–2 to subpart W of part 98 to read as follows:

TABLE W–2 TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS

Equipment components	Emission factor (scf whole gas/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—Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting—All Components, Gas Service			
Valve	9.6	5.5	16
Flange	6.9	4.0	11
Connector (other)	4.9	2.8	7.9
Open-Ended Line [1]	6.3	3.6	10
Pressure Relief Valve	7.8	4.5	13
Pump Seal	14	8.3	23
Other [2]	9.1	5.3	15
Leaker Emission Factors—Onshore Petroleum and Natural Gas Production—All Components, Oil Service			
Valve	5.6	3.3	9.2
Flange	2.7	1.6	4.4
Connector (other)	5.6	3.2	9.1

TABLE W–2 TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS—Continued

Equipment components	Emission factor (scf whole gas/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)
Open-Ended Line	1.6	0.93	2.6
Pump [3]	3.7	2.2	6.0
Other [2]	2.2	1.0	2.9

[1] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors when using the population emission factor approach as specified in § 98.233(o)(10)(iv) or (p)(10)(iv).
[2] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).
[3] The pumps component type in oil service includes agitator seals.

■ 23. Remove tables W–3A and W–3B to subpart W of part 98 and add table W–3 to subpart W of part 98 in numerical order to read as follows:

TABLE W–3 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS

Industry segment	Source type/component	Emission factor (scf total hydrocarbon/ hour/component)
Population Emission Factors—Storage Wellheads, Gas Service		
Underground natural gas storage	Connector	0.01
	Valve	0.1
	Pressure Relief Valve	0.17
	Open-Ended Line	0.03

■ 24. Remove tables W–4A and W–4B to subpart W of part 98 and add table W–4 to subpart W of part 98 in numerical order to read as follows:

TABLE W–4 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS

Equipment components	Emission factor (scf total hydrocarbon/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—Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression—Compressor Components, Gas Service			
Valve [1]	14.84	9.51	24.2
Connector	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter	19.33	12.39	31.6
Other [2]	4.1	2.63	6.70
Leaker Emission Factors—Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression—Non-Compressor Components, Gas Service			
Valve [1]	6.42	4.12	10.5
Connector	5.71	3.66	9.3
Open-Ended Line	11.27	7.22	18.4
Pressure Relief Valve	2.01	1.29	3.28
Meter	2.93	1.88	4.79
Other [2]	4.1	2.63	6.70
Leaker Emission Factors—Underground Natural Gas Storage—Storage Station, Gas Service			
Valve [1]	14.84	9.51	24.2
Connector (other)	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter and Instrument	19.33	12.39	31.6

TABLE W–4 TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS—Continued

Equipment components	Emission factor (scf total hydrocarbon/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)
Other[2]	4.1	2.63	6.70
Leaker Emission Factors—Underground Natural Gas Storage—Storage Wellheads, Gas Service			
Valve[1]	4.5	3.2	7.35
Connector (other than flanges)	1.2	0.7	1.96
Flange	3.8	2.0	6.21
Open-Ended Line	2.5	1.7	4.08
Pressure Relief Valve	4.1	2.5	6.70
Other[2]	4.1	2.5	6.70

[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(d)(7) for onshore natural gas processing, § 98.232(e)(8) for onshore natural gas transmission compression, and as specified in § 98.232(f)(6) and (8) for underground natural gas storage.

■ 25. Remove tables W–5A and W–5B to subpart W of part 98 and add table W–5 to subpart W of part 98 in numerical order to read as follows:

TABLE W–5 TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS

Industry segment	Source type/component	Emission factor (scf methane/hour/component)
Population Emission Factors—LNG Storage Compressor, Gas Service		
LNG storage LNG import and export equipment.	Vapor Recovery Compressor[1]	4.17
Population Emission Factors—Below Grade Transmission-Distribution Transfer Station Components and Below Grade Metering-Regulating Station[2] Components, Gas Service[3]		
Natural gas distribution	Below Grade T–D Transfer Station	0.30
	Below Grade M&R Station	0.30
Population Emission Factors—Distribution Mains, Gas Service[4]		
Natural gas distribution	Unprotected Steel	5.1
	Protected Steel	0.57
	Plastic	0.17
	Cast Iron	6.9
Population Emission Factors—Distribution Services, Gas Service[5]		
Natural gas distribution	Unprotected Steel	0.086
	Protected Steel	0.0077
	Plastic	0.0016
	Copper	0.03
Population Emission Factors—Interconnect, Direct Sale, or Farm Tap Stations[2 3]		
Onshore natural gas transmission pipeline	Transmission Company Interconnect M&R Station	166
	Direct Sale or Farm Tap Station	1.3
Population Emission Factors—Transmission Pipelines, Gas Service[4]		
Onshore natural gas transmission pipeline	Unprotected Steel	0.74
	Protected Steel	0.041
	Plastic	0.061
	Cast Iron	27

[1] Emission Factor is in units of "scf methane/hour/compressor."
[2] Excluding customer meters.
[3] Emission Factor is in units of "scf methane/hour/station."

[4] Emission Factor is in units of "scf methane/hour/mile."
[5] Emission Factor is in units of "scf methane/hour/number of services."

■ 26. Remove tables W–6A and W–6B to subpart W of part 98 and add table W–6 to subpart W of part 98 in numerical order to read as follows:

TABLE W–6 TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS

Equipment components	Emission factor (scf methane/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 and LNG Import and Export Equipment—Storage Components and Terminals Components, LNG Service			
Valve	1.19	0.23	1.94
Pump Seal	4.00	0.73	6.54
Connector	0.34	0.11	0.56
Other [1]	1.77	0.99	2.9
Leaker Emission Factors—LNG Storage and LNG Import and Export Equipment—Storage Components and Terminals Components, Gas Service			
Valve [2]	14.84	9.51	24.2
Connector	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter and Instrument	19.33	12.39	31.6
Other [3]	4.1	2.63	6.70
Leaker Emission Factors—Natural Gas Distribution—Transmission-Distribution Transfer Station [4] Components, Gas Service			
Connector	1.69	....	2.76
Block Valve	0.557	....	0.91
Control Valve	9.34	....	15.3
Pressure Relief Valve	0.27	....	0.44
Orifice Meter	0.212	....	0.35
Regulator	0.772	....	1.26
Open-ended Line	26.131	....	42.7

[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) and § 98.232(h)(7) and (8).
[4] Excluding customer meters.

■ 27. Revise table W–7 to subpart W of part 98 to read as follows:

TABLE W–7 TO SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR INTERNAL COMBUSTION EQUIPMENT

Internal combustion equipment type	Emission factor (kg CH_4/mmBtu)
Reciprocating Engine, 2-stroke lean-burn	0.658
Reciprocating Engine, 4-stroke lean-burn	0.522
Reciprocating Engine, 4-stroke rich-burn	0.045
Gas Turbine	0.004

[FR Doc. 2024–08988 Filed 5–13–24; 8:45 am]

BILLING CODE 6560–50–P