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40 CFR Part 98
Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2011–0512; FRL–9918–95–OAR]

RIN 2060–AR96

Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing revisions and confidentiality determinations for the petroleum and natural gas systems source category and the general provisions of the Greenhouse Gas Reporting Rule. These revisions include changes to certain calculation methods, amendments to certain monitoring and data reporting requirements, clarification of certain terms and definitions, and corrections to certain technical and editorial errors that have been identified during the course of implementation. This action also finalizes confidentiality determinations for new or substantially revised data elements contained in these amendments and revises the confidentiality determination for one existing data element.

DATES: This final rule is effective on January 1, 2015.

ADDRESSES: All documents in the docket are listed in the *http://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, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Docket, EPA/DC, 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: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343–9263; fax number: (202) 343–2342; email address: *GHGReportingRule@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Rule Web site, *http://www.epa.gov/ghgreporting/.* To submit a question, select Help Center, followed by ''Contact Us.''

Worldwide 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 action will be posted on the EPA's Greenhouse Gas Reporting Rule Web site at *http://www.epa.gov/ghgreporting/index.html.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. This final rule revises certain calculation methods, monitoring, and data reporting requirements and finalizes confidentiality determinations for the petroleum and natural gas systems source category and the general provisions of the Greenhouse Gas Reporting Rule (40 CFR part 98). The Administrator determined that 40 CFR part 98 is subject to the provisions of Clean Air Act (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''). Entities affected by this final rule are owners and operators of petroleum and natural gas systems that directly emit greenhouse gases (GHGs), which include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS	Examples of affected facilities
Petroleum and Natural Gas Systems	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.
	221210	Natural gas distribution.
	486210	Pipeline transportation of natural gas.

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. Types of facilities other than those listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A and 40 CFR part 98, subpart W. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

What is the effective date? The final rule is effective on January 1, 2015. Section 553(d) of the Administrative Procedure Act (APA), 5 U.S.C. Chapter 5, generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**. The EPA is issuing this final rule under section 307(d)(1) of the Clean Air Act, which states: ''The provisions of section 553 through 557 * * * of Title 5 shall not, except as expressly provided in this section, apply to actions to which this subsection applies.'' Thus, section 553(d) of the APA does not apply to this rule. The EPA is nevertheless acting consistently with the purposes underlying APA section 553(d) in making this rule effective on January 1, 2015. Section 5 U.S.C. 553(d)(3) allows an effective date less than 30 days after publication ''as otherwise provided by the agency for good cause found and published with the rule.'' As explained below, the EPA finds that there is good cause for this rule to become effective on January 1, 2015, even though this may result in an effective date fewer than 30 days from date of publication in the **Federal Register**.

While this action is being signed prior to December 1, 2014, there is likely to be a significant delay in the publication of this rule as it contains complex equations and tables and is relatively long. As an example, the EPA Administrator signed the Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems proposed rule on February 7, 2014, but the proposed rule was not published in the **Federal Register** until March 10, 2014 (79 FR 13394). The purpose of the 30-day waiting period prescribed in 5 U.S.C. 553(d) is to give affected parties a reasonable time to adjust their

behavior and prepare before the final rule takes effect.

To employ the 5 U.S.C. 553(d)(3) ''good cause'' exemption, an agency must balance the necessity for immediate implementation against principles of fundamental fairness which require that all affected persons be afforded a reasonable amount of time to prepare for the effective date of its ruling.[1] Where, as here, the final rule will be signed and made available on the EPA Web site more than 30 days before the effective date, but where the publication is likely to be delayed due to the complexity and length of the rule, the regulated entities are afforded this reasonable amount of time. This is particularly true given that many of the revisions being made in this package provide flexibilities to sources covered by the reporting rule, or otherwise relieve a restriction. We balance these circumstances with the need for the amendments to be effective by January 1, 2015; a delayed effective date would result in regulatory uncertainty, program disruption, and an inability to have the amendments (many of which clarify requirements, relieve burden, and/or are made at the request of the regulated facilities) effective for the 2015 reporting year. Accordingly, we find good cause exists to make this rule effective on January 1, 2015, consistent with the purposes of 5 U.S.C. 553(d)(3).

Judicial Review. Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit (the Court) by January 26, 2015. 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. Section 307(d)(7)(B) of the CAA also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the 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 to us 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 a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, 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.

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

AGR—acid gas removal
APA—Administrative Procedure Act
API—American Petroleum Institute
BAMM—best available monitoring methods
CAA—Clean Air Act
CBI—confidential business information
CFR—Code of Federal Regulations
CH_4—methane
CO_2—carbon dioxide
CO_2e—carbon dioxide equivalent
EIA—Energy Information Administration
EPA—U.S. Environmental Protection Agency
FERC—Federal Energy Regulatory Commission
FR—Federal Register
GHG—greenhouse gas
GOR—gas to oil ratio
HHV—higher heating value
hp—horsepower
ICR—information collection request
ID—identification
IR—infrared
LNG—liquefied natural gas
mmBtu—million British thermal units
MMscf—million standard cubic feet
N_2O—nitrous oxide
NAICS—North American Industry Classification System
NESHAP—National Emission Standards for Hazardous Air Pollutants
NGL—natural gas liquids
NOD—not-operating-depressurized
NSPS—New Source Performance Standards
NTTAA—National Technology Transfer and Advancement Act
O&M—operation and maintenance
OMB—Office of Management and Budget
psig—pounds per square inch gauge
QA/QC—quality assurance/quality control
REC—reduced emissions completion
RFA—Regulatory Flexibility Act
scf—standard cubic feet
U.S.—United States
UMRA—Unfunded Mandates Reform Act of 1995
WWW—worldwide web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

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I. Background

A. Organization of This Preamble

Section I of this preamble provides background information regarding the origin of the final amendments. This section also discusses the EPA's legal authority under the CAA to promulgate and amend 40 CFR part 98 of the Greenhouse Gas Reporting Rule (hereinafter referred to as ''Part 98'') as well as the legal authority for making confidentiality determinations for the data to be reported. Section II of this preamble contains information on the final revisions to Part 98, subpart W (Petroleum and Natural Gas Systems) (hereinafter referred to as ''subpart W''), including a summary of the major comments that the EPA considered in

[1] *Omnipoint Corp.* v. *FCC,* 78 F3d 620, 630 (D.C. Cir. 1996), quoting *U.S.* v. *Gavrilovic,* 551 F.2d 1099, 1105 (8th Cir. 1977).

the development of this final rule. Section III 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 a revised confidentiality determination for one existing data element. Section IV of this preamble discusses the impacts of the final amendments to subpart W. Finally, Section V of this preamble describes the statutory and executive order requirements applicable to this action.

B. Background on This Action

On October 30, 2009, the EPA published Part 98 for collecting information regarding GHGs from a broad range of industry sectors (74 FR 56260). The 2009 rule, which finalized reporting requirements for 29 source categories, did not include the Petroleum and Natural Gas Systems source category. A subsequent rule was published on November 30, 2010, finalizing the requirements for the Petroleum and Natural Gas Systems source category at 40 CFR part 98, subpart W (75 FR 74458) (hereinafter referred to as ''the subpart W 2010 final rule''). Following promulgation, the EPA finalized several actions revising subpart W (76 FR 22825, April 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 80554, December 23, 2011; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014).

On March 10, 2014, the EPA proposed the ''Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' (79 FR 13394) to make revisions to certain provisions of subpart W, including the clarification and correction of certain calculation methods, monitoring, and reporting requirements for which errors were identified during the course of implementation. At that time, the EPA also proposed confidentiality determinations for new and substantially revised (*i.e.,* requiring additional or different data to be reported) data elements contained in the proposed amendments, as well as a revised confidentiality determination for one existing data element. The public comment period for these proposed rule amendments ended on April 24, 2014.

In this action, the EPA is finalizing certain revisions to the subpart W calculation, monitoring, and reporting requirements with some changes made in response to public comments and one clarifying edit, as proposed, to a definition in the general provisions (Part 98, subpart A) that applies to subpart W reporters. Responses to comments submitted on the proposed amendments can be found in Sections II, III, and IV of this preamble as well as in the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512.

C. Legal Authority

The EPA is finalizing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 final GHG reporting rule (74 FR 56260, October 30, 2009), CAA section 114(a)(1) provides the EPA broad authority to require the information to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out a wide variety of CAA provisions. See the preambles to the proposed (74 FR 16448, April 10, 2009) and final GHG reporting rule (74 FR 56260, October 30, 2009) for further information.

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 and a revised confidentiality determination for one existing data element, required by these amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information that qualifies for confidential treatment. The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA.

D. How do these amendments apply to 2014 and 2015 reports?

These amendments are effective on January 1, 2015. Thus, beginning on January 1, 2015, facilities must follow the revised methods in subpart W, as amended, to calculate emissions occurring during the 2015 calendar year. The first annual reports of emissions calculated using the amended requirements will be those submitted by March 31, 2016, covering the 2015 calendar year. For the 2014 calendar year, reporters will continue to calculate emissions and other relevant data for the reports that are submitted according to the requirements in Part 98 that are applicable to the 2014 calendar year (*i.e.,* the requirements in place until the effective date of this final rule). For this reason, we determined that it was not appropriate to revise Table A–7 to subpart A of Part 98 to reflect the revised reporting requirement section references in this final rule. For the 2011 through 2014 calendar years, subpart W reporters must report any data that are inputs to emissions equations according to the requirements in 40 CFR 98.3(c)(vii) and in Table A–7 to subpart A of Part 98 following the requirements in Part 98 that are applicable for that calendar year. For more information on the reporting of 2011 through 2014 data that are inputs to emissions equations, see 79 FR 63750 (October 24, 2014).

As noted in Section II.D of this preamble, we are providing short-term transitional best available monitoring methods (BAMM) for reporters for emission sources that are subject to new monitoring or measurement requirements as part of these final revisions. These reporters have the option of using BAMM from January 1, 2015, to March 31, 2015, without seeking prior EPA approval for certain parameters that cannot reasonably be measured according to the monitoring and quality assurance/quality control (QA/QC) requirements of 40 CFR 98.234. Reporters also have the opportunity to request an extension for the use of BAMM from April 1, 2015, through December 31, 2015; those owners or operators must submit a request to the EPA by January 31, 2015.

II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment

The EPA is finalizing technical corrections, clarifying revisions, and other amendments to subpart W. These final amendments improve the quality and consistency of the collected data, and many of the changes are in response to feedback received from stakeholders during program implementation. These final amendments include changes to clarify or simplify calculation methods for certain sources at a facility; revisions to units of measure, terms, and definitions in certain equations to provide consistency throughout the rule, provide clarity, or better reflect facility operations; revisions to reporting requirements to clarify and align more closely with the calculation methods and to clearly identify the data that must be reported; and other revisions identified as a result of working with the affected sources.

Sections II.A through II.E of this preamble describe the corrections and other amendments that we are finalizing in this rulemaking. Section II.A describes revisions which provide consistency throughout subpart W, including revisions to definitions. Section II.B describes the final revisions to calculation methods and reporting requirements for the emission source types identified in subpart W. Section II.C describes the final revisions to the

missing data procedures of subpart W. Subpart II.D provides a summary of the final amendments to the best available monitoring requirements. Finally, Section II.E describes the final additions of new data elements and revisions to reporting requirements. The amendments described in each section are followed by a summary of the major comments on those amendments and the EPA's responses. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and the EPA's responses.

In addition to the specific revisions or amendments discussed in this section of the preamble, the EPA is finalizing minor technical revisions to subpart W. These revisions improve readability, create consistency in terminology, and/or correct typographical or other errors in subpart W to improve the final rule. These final revisions are further explained in the memorandum, ''Minor Technical Corrections to Subpart W, Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule'' and the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512.

A. Summary of Final Revisions To Provide Consistency Throughout Subpart W

This section includes minor cascading revisions that affect multiple requirements of subpart W. Sections II.A.1 through II.A.3 describe the amendments we are finalizing in this rulemaking and, if major comments were received, provide a summary of the major comments and the EPA's responses.

1. Consistency in Units of Measure for Emissions Reporting

The EPA is amending 40 CFR 98.236 to revise the reporting of GHG emissions from units of metric tons of carbon dioxide equivalent (CO_2e) of each reported GHG to metric tons of each reported GHG. Specifically, we are revising the units of emissions reported in 40 CFR 98.236 to require reporting in metric tons of methane (CH_4), carbon dioxide (CO_2), and nitrous oxide (N_2O), as applicable, instead of reporting each gas in metric tons of CO_2e. The cumulative GHG emissions in units of metric tons of CO_2e across all pollutants will also be reported as required in the general provisions at 40 CFR 98.3(c)(4)(i). These changes increase consistency between the reporting requirements for subpart W and the rest of Part 98, which generally requires the reporting of metric tons of individual GHGs. The EPA received only supportive comments to these revisions. The final amendments remove a reference to CO_2e in the introductory paragraph of 40 CFR 98.236(a) that was inadvertently retained in the proposal. Otherwise, these revisions are finalized as proposed.

2. Onshore Production Source Category Definition

a. Summary of Final Revisions

We are finalizing, with minor changes from proposal, amendments to the source category definition of ''onshore petroleum and natural gas production'' at 40 CFR 98.230(a)(2) to clarify the emission sources covered for purposes of GHG reporting. As proposed, we are adding references to engines, boilers, heaters, flares, and separation and processing equipment, and we are removing references to gravity separation equipment and auxiliary non-transportation-related equipment for being redundant with other sources specified in the definition. In this final rule, we are not including the reference to ''maintenance and repair equipment'' that was included in the proposed rule after considering public comments indicating confusion regarding that proposed text. Thus, the first sentence of 40 CFR 98.230(a)(2) reads, ''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).''

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to the source category definition of ''onshore petroleum and natural gas production.'' See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and the EPA's responses.

Comment: Two commenters supported part of the proposed revisions to the source category definition of ''onshore petroleum and natural gas production'' at 40 CFR 98.230(a)(2). These commenters supported the removal of the term ''auxiliary non-transportation related equipment'' but objected to the addition of the term ''maintenance and repair equipment.'' One commenter asserted that based on the current rule language, maintenance and repair equipment is not included in the onshore production industry segment because this equipment is not directly used in the production, extraction, recovery, lifting, stabilization, separation, or treating of petroleum and natural gas. Two commenters pointed to the description of stationary or portable fuel combustion equipment in 40 CFR 98.232(c)(22), which includes only emissions from equipment that is ''integral to the extraction, processing, or movement of oil or natural gas.'' These commenters asserted that maintenance and repair equipment is not integral. The commenters stated that the proposed rule expands the definition, which places an undue burden on industry because emissions from maintenance and repair equipment, such as welding machines and pressure washers, are small relative to integral equipment like prime movers, and the equipment is frequently moved between well sites and tracking is difficult. The commenters requested that the EPA remove the term ''maintenance and repair equipment'' from the final definition.

Response: The EPA recognizes that, by specifically including reference to maintenance and repair equipment within the parenthetical, some reporters may misinterpret that to mean all maintenance and repair equipment, regardless of whether or not that equipment is actually used in the production, extraction, recovery, lifting, stabilization, and separation or treating of petroleum and/or natural gas. This was not our intent. To reduce the potential for confusion, we are removing the reference to ''maintenance and repair equipment'' from the source category definition for the onshore petroleum and natural gas production segment in this final rule. However, the EPA notes that the parenthetical list is not an all-inclusive list (''. . . including but not limited to . . .'') and, as noted at 40 CFR 98.232(c)(22), if the facility has maintenance and repair equipment that is integral to the continued production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas, then it would be covered by the onshore petroleum and natural gas production segment.

With respect to the need to determine combustion emissions from maintenance and repair equipment, 40 CFR 98.232(c)(22) requires emissions ''. . . from stationary or portable fuel combustion equipment that cannot move under its own power or drive train, and that is located at an onshore petroleum and natural gas production facility . . .'' to be reported. 40 CFR 98.232(c)(22) further specifies that ''[s]tationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: Well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers and process heaters.'' The list provided in 40 CFR 98.232(c)(7)(22) is not open-ended and few pieces of ''maintenance and repair equipment'' would qualify as ''stationary or portable equipment'' for which combustion emissions must be calculated and reported. If the maintenance and repair equipment have applicable combustion emissions, reporters must report the emissions from this equipment provided that it includes external combustion sources with rated heat capacity greater than 5 million British thermal units (mmBtu) per hour or internal fuel combustion sources with rated heat capacity greater than 1 mmBtu per hour (or 130 horsepower (hp)), as specified in 40 CFR 98.233(z).

3. Definition of Sub-Basin Category

a. Summary of Final Revisions

The EPA is finalizing, as proposed, revisions to the definition of sub-basin category at 40 CFR 98.238. Specifically, we have defined sub-basin category as ''a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight gas reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with greater than 0.1 millidarcy permeability and tight gas reservoirs with less than or equal to 0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce only from high permeability gas, shale gas, coal seam, or other tight gas reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids (with or without gas) and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight gas reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.''

b. Summary of Comments and Responses

The EPA received only supportive comments regarding these revisions, therefore, there are no changes from proposal to the final rule based on these comments.

B. Summary of Final Revisions to Calculation Methods and Reporting Requirements

The final amendments described in this section include technical revisions and corrections to the calculation and reporting requirements of subpart W. In general, these revisions provide greater flexibility and potentially reduce burden to facilities, and they increase the clarity and congruency of the calculation and reporting requirements.

These final amendments also include organizational revisions to the reporting requirements in 40 CFR 98.236. These revisions restructure 40 CFR 98.236 to more closely align the reporting requirements with the calculation methods, clarify the data elements to be reported, and improve data utility. As proposed, we are reorganizing the reporting section by source type and, for each industry segment, listing which source types must be reported. We are also finalizing the addition of new data elements which would improve the quality of the data reported. These additional data elements are discussed in Section II.E of this preamble.

The final amendments to the calculation and reporting requirements in subpart W are described in this section by emission source type (*e.g.,* natural gas pneumatic device venting, acid gas removal vents, etc.). The amendments for each source type are followed by a summary of the major comments, if any, on those amendments and the EPA's responses. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and the EPA's responses. Additional minor corrections, including minor edits to the calculation requirements of the final rule, are included in the memorandum, ''Minor Technical Corrections to Subpart W, Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule'' in Docket Id. No. EPA–HQ–OAR–2011–0512. Further information on the final changes to the reporting section may be found in the memorandum, ''Final Revisions to the Subpart W Reporting Requirements in the 'Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket Id. No. EPA–HQ–OAR–2011–0512.

1. Natural Gas Pneumatic Device Venting

a. Summary of Final Revisions

We are finalizing revisions to Equation W–1 in 40 CFR 98.233(a) to sum the natural gas pneumatic device venting emissions across all types of pneumatic devices with minor revisions. We are revising the summation symbol to remove the ''i'' at the bottom of the summation symbol, which was inadvertently included with the summation symbol. This revision is needed to clarify that the summation is across different types of pneumatic devices (designated by ''t'') and not across different GHGs (designated by ''i''). We are finalizing revisions to 40 CFR 98.233(a)(1), (a)(2), and (a)(3) as proposed to simplify how ''$Count_t$'' of Equation W–1 (total number of natural gas pneumatic devices of type ''t'') must be calculated each year as new devices are added. For the onshore petroleum and natural gas production industry segment, reporters continue to have the option in the first two reporting years to estimate ''$Count_t$'' using engineering estimates. The EPA is also finalizing the reporting requirements with minor revisions from proposal. Specifically, the EPA is clarifying that certain reporting requirements in 40 CFR 98.236(b)(1) and (2) should be reported by device type. These revisions clarify our original intent and address public comments received.

b. Summary of Comments and Responses

Comment: One commenter noted that it appears that the EPA is removing the requirement to report information separately for each pneumatic controller type (continuous high bleed, continuous low bleed, intermittent bleed) and is instead requesting that all information from all three categories be lumped together in the proposed revisions to 40

CFR 98.236(b). According to the commenter, this seems like a backwards step in data collection and, given the current high interest in pneumatic controllers in oil and gas sector studies and by the EPA in technical white papers on the oil and gas sector, it seems illogical for the EPA to stop collecting this device-type-specific information. The commenter also noted a discrepancy between the proposed rule text at 40 CFR 98.236(b), which says ''you must report the information specified in paragraphs (b)(1) through (b)(4) of this section'' while the memorandum entitled ''Revisions to the Subpart W Reporting Requirements as proposed in the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' says ''you must report the information specified in paragraphs (b)(1) through (b)(4) of this section for each device type.''

Response: The EPA agrees with the commenter that certain reporting elements in 40 CFR 98.236(b) should be reported by device type. We removed the phrase ''for each device type'' from paragraph 40 CFR 98.236(b) prior to proposal because the reporting elements in paragraphs (b)(3) and (b)(4) are aggregate emissions across the three device types (''. . . combined, calculated using Equation W–1''). It was not our intent to collect aggregated data regarding the number of pneumatic devices. For example, the reporting element in paragraph 40 CFR 98.236(b)(2) specifically indicates that the reporting element is ''T_t'' in Equation W–1, which is specific to the type of pneumatic device. To address this issue, we are revising paragraphs (b)(1)(i), (b)(1)(ii)(A) and (B), and (b)(2) to indicate that these reporting elements must be reported for each type of pneumatic device. These data will allow the EPA to verify the aggregate emissions calculated using Equation W–1 and perform more detailed analysis of emissions by device type.

2. Acid Gas Removal Vents

a. Summary of Final Revisions

For acid gas removal (AGR) vents, we are finalizing several technical revisions as proposed and adding minor clarifying revisions to address public comments received. We are finalizing minor clarifying edits to 40 CFR 98.233(d) as proposed to clearly label each calculation method and to clarify provisions by providing references to equations where appropriate. We are also finalizing the proposed revisions to the parameters ''Vol_{CO2}'' in Equation W–3 and parameters ''Vol_I'' and ''Vol_O'' in Equation W–4A and W–4B to clarify that the volumetric fraction used should be the annual average. As proposed, we are specifying in 40 CFR 98.233(d)(8) that reporters may use sales line quality specifications for CO_2 in natural gas only if a continuous gas analyzer is not available.

In response to public comments, we are making four minor corrections and clarifying revisions to the calculation and reporting requirements for AGR units. First, we are removing an errant proposed requirement in 40 CFR 98.236(d)(10) to calculate annual mass emissions ''at standard conditions.'' Second, in response to a comment that the sub-basin identification (ID) reporting requirement in 40 CFR 98.236(d)(1)(vi) is unclear when an AGR unit treats gas from wells in more than one sub-basin, we are revising the data element to require reporting of the sub-basin ID ''that best represents the wells supplying gas to the unit.'' Third, in response to comments on the proposed missing data procedures for AGR units (proposed 40 CFR 98.235(a), we are adding the clause ''. . . for each quarter that the AGR unit is operating . . .'' in paragraphs 40 CFR 98.233(d)(6), (7), and (8)(ii) to clarify that quarterly samples are only required to be collected for quarters when the unit is operated. Fourth, in response to a comment on the proposed confidentiality determinations for AGR units, we are correcting the reporting requirements for the amount of CO_2 from AGR units that is recovered and transferred outside the facility (40 CFR 98.236(d)(1)(iv)); the requirement to report this quantity ''under subpart PP'' was inadvertently omitted from the proposed rule. See Section II.C of this preamble for additional discussion of changes to the missing data procedures related to AGR units, and see Section III.B of this preamble for additional discussion of the confidentiality determination for the data element related to reporting the amount of CO_2 recovered and transferred outside the facility.

b. Summary of Comments and Responses

The EPA did not receive any major comments on the proposed revisions to the calculation and reporting requirements for AGR units. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

3. Dehydrators

a. Summary of Final Revisions

The EPA is clarifying that Calculation Method 1 in 40 CFR 98.236(e)(1) is not applicable to desiccant dehydrators. We proposed this clarification by including the word ''absorbent'' to describe the types of dehydrators for which Calculation Method 1 applies. We received comment that the term ''absorbent dehydrators'' was not a common term used by industry and was not defined in the rule. We are finalizing amendments to both 40 CFR 98.236(e)(1) and (e)(3) to clarify our original intent that Calculation Method 1 is applicable to glycol (liquid absorbent) dehydrators and that emissions from desiccant dehydrators of any size should be determined using Calculation Method 3 in 40 CFR 98.236(e)(3). We are finalizing revisions as proposed to clarify that the 0.4 million standard cubic feet (MMscf) per day throughput relates to the natural gas throughput of the dehydrator for determining the applicability of Calculation Method 1. We are finalizing revisions to clarify the calculation methods for dehydrators to provide for the adjustment of emissions vented to a vapor recovery system as proposed. We are finalizing clarifications to the calculation of emissions when vented to a flare with minor revisions to those proposed. Specifically, we are including reference to 40 CFR 98.233(e)(5) in paragraph (e)(6)(i) in the event a portion of the dehydrator vent emissions are recovered and a portion are vented to a flare. Finally, we are finalizing, as proposed, clarification to the reporting requirements in 40 CFR 98.236(e)(2) for glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscf per day to account for scenarios in which a dehydrator may be vented to more than one emission point (*e.g.,* with one vent routed to a flare and one vent routed to vapor recovery).

b. Summary of Comments and Responses

Comment: One commenter objected to the term ''absorbent dehydrator.'' The commenter stated that this is not a term used by industry, is not defined in the rule, and may cause confusion with desiccant dehydrator requirements as they use an absorbent. The commenter recommended the term ''glycol dehydrator'' be used rather the proposed ''absorbent dehydrator'' term.

Response: The EPA agrees with the commenter in that desiccant dehydrators use a solid absorbent, so the term ''absorbent dehydrator'' is

ambiguous. We considered amending the descriptive clause to ''liquid absorbent'' dehydrators; however, based on available information, liquid absorbent systems use glycol and the term glycol dehydrators is already used to describe the dehydrators for which Calculation Method 2 is applicable. Therefore, to clarify our original intent, we are replacing the proposed ''absorbent dehydrator'' term with the term ''glycol dehydrator'' in the first sentence in 40 CFR 98.236(e)(1). We are also revising the first sentence in 40 CFR 98.233(e)(3) to begin as follows: ''For dehydrators of any size that use desiccant, you must calculate emissions . . .'' These edits clarify our original intent and address the commenter's concerns regarding the proposed ''absorbent dehydrator'' term.

4. Well Venting for Liquids Unloading

a. Summary of Final Revisions

As proposed, the EPA is revising the calculation and reporting requirements for well venting from liquids unloading. These revisions include allowances for annualizing venting data for facilities that calculate emissions using a recording flow meter (Calculation Method 1 at 40 CFR 98.233(f)(1)); revisions to Calculation Method 1 at 40 CFR 98.233(f)(1) and reporting requirements at 40 CFR 98.236 to separate the calculation and reporting of emissions from wells that have plunger lifts and wells that do not have plunger lifts; and clarification of the term ''SP_p'' in Equation W–8 (40 CFR 98.233(f)(2)) to specify that, if casing pressure is not available for each well, reporters may determine the casing pressure using a ratio of the casing pressure to tubing pressure from a well in the same sub-basin where the casing pressure is known.

b. Summary of Comments and Responses

The EPA received supportive comments for the proposed revisions and did not receive major comments opposing the proposed revisions to the calculation and reporting requirements for well venting from liquids unloading. The EPA is not making any changes to the proposed amendments in the final rule as a result of public comments. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

5. Gas Well Completions and Workovers

a. Summary of Final Revisions

The EPA is finalizing several definitions pertinent to gas well completions and workovers. The EPA is finalizing amendments to 40 CFR 98.238 to add definitions for ''reduced emissions completion'' and ''reduced emissions workover'' with minor revisions from the proposed definitions. The proposed definitions of these terms implied that there would be no direct releases to the atmosphere. Public comments indicated that this phrase was too restrictive and we have revised the definition to clarify that a ''reduced emissions completion'' or a ''reduced emissions workover'' will have de minimis venting to the atmosphere and may have short periods of flaring. The EPA is finalizing as proposed the definition of ''well completions'' in 40 CFR 98.6 of subpart A to delete the term ''re-fracture'' as this term applies to an already producing well and is considered a well workover, not a well completion, for the purposes of part 98.

We are also revising the reporting requirements for gas well completions and workovers to differentiate between different well type combinations in each sub-basin category, as proposed. A well type combination is a unique combination of the following factors: Vertical or horizontal, with flaring or without flaring, and reduced emissions completion (REC)/workover or no REC/workover.

As proposed, we are revising Equation W–10A, the time variable ''T_p'' in Equation W–10A and W–10B, the calculation section at 40 CFR 98.233(g) and (h), and Equation W–13 in 40 CFR 98.233(h) and adding new Equation W–13B in 40 CFR 98.233(h). We are revising 40 CFR 98.233(g)(1) and (g)(2) as proposed to clarify measurement requirements. We are also finalizing revisions as proposed for the parameter ''$PR_{s,p}$'' in Equations W–10A and W–10B and Equation W–12 to clarify that the first 30 day average production flow rate is the average taken after completions of newly drilled gas wells or workovers.

The final rule also corrects two errors in the proposed reporting requirements in 40 CFR 98.236(g)(5)(i) so that the final reporting requirements are consistent with the variables used in the revised Equation W–10A. First, the final rule uses the term ''flowback'' instead of ''backflow.'' Second, instead of requiring reporting of the ''cumulative backflow time,'' which is an artifact of requirements in the subpart W 2010 final rule, the final 40 CFR 98.236(g)(5)(i) requires reporting of the cumulative gas flowback time from when gas is first detected until sufficient quantities are present to enable separation (''$T_{p,i}$'' in Equation W–10A) and the cumulative flowback time after sufficient quantities of gas are present to enable separation (''$T_{p,s}$'' in Equation W–10A).

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed amendments to gas well completions and workovers. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: Two commenters asserted that the proposed rule significantly increases the burden by expanding the definition of well type in 40 CFR 98.233(g)(2) to differentiate between the scenarios of with or without flaring and with REC/workover or without REC/workover. The commenters stated that expanding the well type definition increases the maximum number of measurement combinations to be reported from 10 (five formation types and two well types) to 40 (five formation types and eight well types). Additionally, one commenter stated that it is difficult for reporters to identify and plan for which wells to measure, because the reporter cannot predict whether a well will need a flare or a vent until after beginning the actual flowback. The commenter noted that implementation of 40 CFR part 60, subpart OOOO, will sharply reduce, but not eliminate, the number of flowbacks where gas is not flared and/or RECs are not performed; therefore, these scenarios will still be present and would need to be measured. Another commenter requested that the EPA reconsider splitting the reporting and measurement categories for well completions and workovers because reporters have established data collection and management systems based on the existing well types. The commenter stated that the proposed changes would double or quadruple the number of required measurements or calculations, input data management, and reporting requirements. One commenter supported the changes in the data collection, stating that disaggregated data will help distinguish emissions by well type and control technology, facilitate a deeper understanding of the factors affecting oil and gas sector emissions, and improve the data for use in the Inventory of U.S. Greenhouse Gas Emissions and Sinks.

Response: In the final rule, the EPA is maintaining the requirement to measure emissions separately per sub-basin and well type combination instead of aggregations of these distinct operational practices. As some commenters noted, the disaggregated

data will improve data quality for emissions from gas well completions and workovers with hydraulic fracturing. We disagree with some of the commenters that the new requirements will impose a significant additional burden on reporters. The EPA expects that operational practices will generally be the same in a given sub-basin and considers it unlikely that a reporter would conduct drilling activities for a given sub-basin in all the different well type combinations of vertical or horizontal, with flaring or without flaring, and REC/workover or no REC/workover. For example, gas well hydraulic fracturing focused on horizontal drilling in a shale gas formation in a county using reduced emissions completions and flaring would constitute one category. As one commenter noted, owners or operators of gas wells must comply with 40 CFR part 60, subpart OOOO. While some of the other categories may be present for some reporters, compliance with subpart OOOO will result in most reporters being in the category of reduced emissions completions with flaring. Additionally, subpart W provides flexibility by allowing reporters to determine flowback rates using engineering calculations provided in Equations W–11A or W–11B.

Comment: One commenter asked whether the proposed definition for REC was intended to be consistent with the definition used in 40 CFR part 60, subpart OOOO. The commenter requested that if this is the EPA's intent, then the definition should be expanded to clarify that there may be some degree of venting during some portion of the flowback period. The commenter stated that the proposed Part 98 definition does not acknowledge that flowback is vented, and that the definition should include clarification. The commenter noted that, as proposed, the definition of ''reduced emissions completion'' would result in no RECs reported due to the phrase ''no direct release to the atmosphere.'' In addition, the commenter stated that the subpart W definition does not provide for flaring to occur on wells with RECs. The commenter requested that the EPA modify the definition for reduced emission completions to harmonize with the revised calculation approach for completions and workovers with hydraulic fracturing, which addresses the small amount of venting during initial flowback and provides for flaring associated with well completions and workovers.

Response: We agree with the commenter that there can be a small amount of venting during the initial flowback, and that in some situations flaring is conducted. In the final rule we are revising the definitions of ''reduced emissions completion'' and ''reduced emissions workover'' to clarify the venting and flaring activities that may occur.

6. Blowdown Vents

a. Summary of Final Revisions

The EPA is finalizing, with some modifications, the proposed revisions to include a compressibility term in Equations W–14A and W–14B for calculating emissions from blowdown vents and also in Equations W–33 and W–34 to convert volumetric emissions at actual conditions to standard conditions. The EPA proposed to allow reporters to use a compressibility factor of 1 under certain temperature and pressure conditions, otherwise a site-specific compressibility factor must be calculated and used for each blowdown event or conversion to standard conditions. Commenters indicated that these requirements posed a significant burden on reporters without significantly improving the calculated emissions. After considering the public comments, we are finalizing the inclusion of the compressibility term in Equations W–14A, W–14B, W–33 and W–34, but we are optionally allowing reporters to use a default value of 1 or a site-specific compressibility factor regardless of the temperature and pressure conditions.

The EPA is finalizing the equipment type categories and the reporting requirements for blowdown vents with minor modifications to those proposed. In the final rule, we have incorporated the term ''equipment or event type'' rather than simply ''equipment type'' where appropriate to include reference to emergency shutdown blowdown activities. We clarified the ''emergency shutdown'' category to include all emergency shutdown blowdown emissions regardless of equipment type. We also revised the category proposed as ''station piping'' to be ''facility piping'' to be more applicable to the onshore natural gas processing and liquefied natural gas (LNG) import and export equipment industry segments; we also clarified the distinction between ''facility piping'' and ''pipeline venting.'' We also revised the category proposed as ''all the other blowdowns greater than or equal to 50 cubic feet'' category to ''all other equipment with a physical volume greater than or equal to 50 cubic feet'' to clarify it is the physical volume of the equipment, not the blowdown volume (converted to standard conditions), to which the 50 cubic feet threshold applies.

The EPA is also adding an optional calculation method (40 CFR 98.233(i)(3)) for blowdown emissions for situations where a flow meter is in place and including associated reporting requirements in 40 CFR 98.236. If a flow meter is in place to measure emissions, the emissions are reported on a facility basis and would not be aggregated by emission type per 40 CFR 98.236(i)(2). These revisions are finalized with minor revisions to clarify that reporters may use flow meters for some blowdown stacks and use equipment or event type calculations for other blowdown vent stacks at the same facility.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to blowdown vent emissions. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: Three commenters opposed the proposed mandatory use of a compressibility factor (Z) in equations W–14A, W–14B, W–33, and W–34. The commenters stressed that requiring the calculation of Z places a significant burden on industry without producing a substantive benefit in terms of increased data and emissions accuracy. One commenter also claimed that the inclusion of a mandatory compressibility factor would result in inconsistencies with prior year reports. The three commenters supported allowing the optional use of a compressibility factor that would not impose new burdens but would provide greater flexibility to reporters. One commenter asserted that some companies already use a compressibility term in their blowdown emission calculations, and some reporters have existing company algorithms and programs used to track blowdown venting and calculations emissions that account for compressibility. Another commenter stated that mandating the use of the compressibility factor in the blowdown vent calculations would require changes to these existing systems and increase implementation costs. The commenters argued that the EPA has not considered or justified these costs.

One commenter noted that the proposed conditions for using the compressibility term would require the calculation of Z for nearly all equipment blowdown calculations at transmission and storage facilities. The commenter stated that transmission pipelines

typically operate in the range of about 500 to about 1,000 pounds per square inch gauge (psig), therefore the proposed rule would require a calculated value of Z for most, if not all, transmission segment blowdown emission calculations. One commenter asserted that the EPA has not demonstrated that inclusion of the compressibility factor will significantly or cost-effectively reduce the overall uncertainty of the blowdown vent emission estimates. The commenter disagreed with the EPA's assessment of uncertainty and argued that the potential uncertainty introduced by failure to use a compressibility factor is only on the order of 10 percent.

Response: The EPA evaluated the commenters' concerns and is changing the requirements from proposal. We have revised the final rule to allow reporters the option to use a default compressibility factor or a site-specific factor instead of being required to use a site specific factor for specific temperature and pressure ranges. We maintain that the accuracy of the emission calculation is improved if a compressibility factor is included. However, we also recognize the commenters' concern that, for many reporters, programs and algorithms are already in place that do not include the site-specific factor in the calculations, and any revision would incur additional burden and cost in updating the programs and algorithms. We agree with the commenters' suggestion to allow the optional use of site-specific compressibility factors. This approach allows for improved accuracy for facilities that have processes in place to determine site-specific compressibility factors, while not increasing the burden to facilities that do not. Therefore, in this final rule, reporters may use either a default value of 1 or a site-specific compressibility factor regardless of the temperature or pressure range of the system.

Comment: Several commenters supported the use of equipment type categories for aggregating and reporting blowdown emissions, but one of these commenters stated that the rule should allow reporters to optionally report emissions by unique blowdown volumes. Two commenters requested clarification of several of the blowdown categories. First, the commenters recommended that the seven categories be called ''equipment/event types'' to more accurately describe the ''emergency shutdown'' category. The commenters suggested that the EPA clarify that emergency shutdown blowdown emissions should always be categorized under the ''emergency shutdown'' category, regardless of the type of equipment that is blown down and that the EPA should clarify the distinction between ''station piping'' (*i.e.,* within the compressor station boundary) and ''pipeline venting'' (*i.e.,* pipe external to the compressor station that is vented within the station boundary). Finally, the commenters recommended that the category ''all other blowdowns greater than or equal to 50 cubic feet'' should be ''all other equipment with a physical volume greater than or equal to 50 cubic feet.'' One commenter also recommended that the EPA include clarification that, if a blowdown event results in emissions across multiple equipment types and the emissions cannot be apportioned to the different equipment types, then the reporter may categorize the emissions to the equipment type that represents the largest portion of the emissions from the blowdown event.

Response: The EPA disagrees with the one commenter's suggestion to make the blowdown categories optional. The EPA, as well as other commenters, have agreed that the requirement reduces burden and simplifies the rule. Providing the categories as optional to reporters would result in inconsistencies in the reported data and may limit the EPA's ability to compare and review information between reporters. The EPA agrees with the commenters that further clarification would be helpful regarding the categories for reporting blowdown emissions. In the final rule, we have incorporated the term ''equipment or event type'' when referring to all seven categories to more clearly include emergency shutdown blowdown activities. We also revised the emergency shutdown category to indicate that this category includes emergency shutdown blowdown emissions regardless of equipment type. In reviewing the commenters' suggested clarification of station piping and pipeline venting, we found that the nomenclature was very specific to onshore natural gas transmission compression industry segment, but blowdown emissions may also be reported for the onshore natural gas processing and LNG import and export equipment industry segments. Therefore, we have revised the ''station piping'' category to be ''facility piping.'' We have also clarified that station piping refers to ''piping within the facility boundary other than physical volumes associated with distribution pipelines'' and that pipeline venting refers to ''physical volumes associated with distribution pipelines vented within the facility boundary.'' We also revised the category proposed as ''all the other blowdowns greater than or equal to 50 cubic feet'' category to ''all other equipment with a physical volume greater than or equal to 50 cubic feet'' to clarify it is the physical volume of the equipment, not the blowdown volume (converted to standard conditions), to which the 50 cubic feet threshold applies. Finally, we are incorporating the commenter's suggestion to specify that if a blowdown event results in emissions across multiple equipment types and the emissions cannot be apportioned to the different equipment types, then the reporter may categorize the emissions to the equipment type that represents the largest portion of the emissions from the blowdown event. We note that the phrase ''equipment type'' is correct here because this assignment would only be necessary if the blowdown event is not associated with an emergency shutdown.

Comment: One commenter recommended that the rule should clearly indicate that both the method for determining emissions from blowdown vent stacks using a flow meter and the method for determining emissions from blowdown vent stacks according to equipment type can be used for different blowdown emission sources at a given facility. The commenter also recommended that the rule clearly indicate that, when a flow meter is used, that it is not necessary to categorize emissions by equipment type.

Response: The EPA has evaluated the commenter's suggestions and agrees that the changes would clarify the rule. In the final rule, the EPA is clarifying in 40 CFR 98.233(i) that the facility may use the equipment/event type method for some blowdown vent stacks and use the flow meter for other blowdown vent stacks. We are also clarifying the reporting requirements in 40 CFR 98.236(i) to accommodate reporting when both calculation methods are used. Facility owners or operators must report by the equipment/event type categories for the blowdown stack vents that use the equipment or event type calculation method and they must report the cumulative emissions for all blowdown vent stacks that use flow meters to determine blowdown emissions.

Comment: Two commenters recommended a change to the emissions calculations for blowdown volumes. The commenters asserted that the current order of calculations for blowdown vents is incorrect. The commenters noted that gases in the same equipment can have very different compositions, and that the

presumptions in the proposed rule, which would apply the same gas composition to all equipment types, would not represent actual emissions. The commenters suggested that emissions be summed into equipment types after applying applicable gas compositions (*i.e.,* after application of 40 CFR 98.233(u) and (v)) to each individual unique physical volume.

Response: The EPA evaluated the order of the emissions calculations for blowdown volumes presented in the proposed rule and agrees that, for certain industry segments, the order of calculations would introduce inaccuracies and create confusion over which gas compositions to use in the calculation. For certain industry segments, such as onshore natural gas transmission compression and LNG import and export equipment, the order of the summation does not introduce inaccuracies because the gas composition is expected to be the same in all equipment at the facility. Therefore, in the final rule, the EPA has revised the order of calculations to first require that the CH_4 and CO_2 volumetric and mass emissions be calculated for each physical volume (*e.g.,* the inlet volume) associated with each equipment or event category. The total annual CH_4 and CO_2 mass emissions must then be calculated for each equipment or event category by summing the CH_4 and CO_2 mass emissions for all unique physical volumes associated with the equipment or event category. These changes allow reporters to apply the appropriate gas composition for each physical volume prior to aggregating emissions by equipment or event type. However, the final rule also allows reporters in the onshore natural gas transmission compression and LNG import and export equipment sectors to elect to sum their natural gas volumetric emissions first and then apply composition data to determine CH_4 and CO_2 volumetric and mass emissions since the composition data is expected to be the same for all volumes.

7. Onshore Production Storage Tanks

a. Summary of Final Revisions

We are finalizing revisions to the introductory text at 40 CFR 98.233(j) with minor modifications to those proposed to clarify the calculation methods that must be used for onshore production storage tanks. We are also finalizing amendments to 40 CFR 98.233(j)(6), with minor modifications to those proposed. We received comment that the proposed revisions to 40 CFR 98.233(j)(6) appeared to expand the applicability of this requirement to all tanks rather than tanks with an annual average daily throughput of 10 barrels per day or more. This was an inadvertent error. Therefore, we are clarifying in this final rule, both in the 40 CFR 98.233(j) introductory text and 40 CFR 98.233(j)(4), that you must calculate emissions from dump valve leakage only if you use Calculation Method 1 or Calculation Method 2. We are also revising the parameter ''E_n'' in Equation W–16 from the proposed rule to remove the reference to Calculation Method 3, which was erroneously included in the proposed rule.

In reviewing the comments received on the proposed rule, we noted inconsistencies in Calculation Method 2 between the calculation method described in 40 CFR 98.233(j)(2) and the implementation of that method as described in paragraphs (j)(2)(i) and (j)(2)(ii). In the proposed rule, we attempted to consolidate within Calculation Method 2 the calculation methods for storage tanks receiving oil directly from the production well without passing through a wellhead separator and storage tanks receiving oil from a wellhead separator. The introductory text in the proposed paragraph (j)(2) references composition at the separator temperature and pressure, which is appropriate if there is a separator, but it also requires use of either paragraphs (j)(2)(i) and (j)(2)(ii), both of which describe composition at the wellhead, which is only appropriate if there is not a separator. Therefore, we are revising Calculation Method 2 to more clearly designate that the composition at separator temperature and pressure should be used if the storage tank receives oil after passing through a separator and to use the wellhead composition if the tank receives oil directly from the well.

We are finalizing the amendments to the reporting requirements for onshore production storage tanks as proposed (except as described in Section III.A. of this preamble).

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to onshore production storage tanks. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: Two commenters objected to proposed revisions in 40 CFR 98.233(j)(6) that appeared to expand the reporting of emissions from stuck dump valves to all tanks, including those with throughput less than 10 barrels per day. One commenter considered this expansion in reporting to be burdensome and costly, given the investments already made to manage data collection in response to the original rule.

Response: We agree with the commenters that the calculation methods in (j)(6), as proposed, would apply to all storage tanks that have dump valves that are not closing properly, while Equation W–16 previously did not consider emissions from storage tanks with throughput less than 10 barrels per day. It was not the EPA's intent to require reporting of emissions from stuck dump valves to storage tanks with a throughput less than 10 barrels per day. Therefore, we are clarifying in 40 CFR 98.233(j) and 40 CFR 98.233(j)(6) that you must calculate emissions from dump valve leakage only if you use Calculation Method 1 or Calculation Method 2 (applicable for storage tanks with a throughput of 10 barrels per day or more). We are also revising the parameter ''E_n'' in Equation W–16 from the proposed rule to remove the reference to Calculation Method 3, which was erroneously included in the proposed rule.

8. Transmission Storage Tanks

a. Summary of Final Revisions

We are finalizing revisions to the provisions for transmission storage tanks in 40 CFR 98.233(k) with minor modification to those proposed to reorder the calculations in response to comments received. We are finalizing the amendments to the reporting requirements for transmission storage tanks with minor revisions to correct section number references to the reordered paragraphs in 40 CFR 98.233(k) and other editorial revisions in response to comments received.

b. Summary of Comments and Responses

Comment: One commenter noted that the order of the requirements in 40 CFR 98.233(k) were confusing and should be changed to match the actual calculation progression. The commenter noted that cross-references in the reporting section at 40 CFR 98.236(k) will need to be revised if the calculation order is revised.

Response: We reviewed the proposed calculation order and agree with the commenter that the calculation order should be clarified. We moved the calculations for determining annual emissions proposed at 40 CFR 98.233(k)(2)(iii) and (k)(2)(iv) to a new paragraph 40 CFR 98.233(k)(4) and renumbered the flare calculation

paragraph from (k)(4) to (k)(5). We made corresponding revisions to the cross-references in 40 CFR 98.236(k).

9. Associated Gas Venting and Flaring

a. Summary of Final Revisions

In order to improve data quality and avoid over-estimating emissions, the EPA is finalizing revisions to Equation W–18 (40 CFR 98.233(m)(3)) to add the term ''$SG_{p,q}$'' as proposed to account for situations where part of the associated gas from a well goes to a sales line while another part of the gas is flared or vented. The EPA is not finalizing the addition of the proposed term ''$ERE_{p,q}$'' for emissions reported under other sources, because the overlap in emissions reported elsewhere has been determined by the EPA to be negligible and because commenters have identified these emissions as potentially burdensome to track. The EPA is also finalizing revisions as proposed to the term ''$GOR_{p,q}$'' and the emission result ''$E_{s,n}$'' in Equation W–18 to specify that the gas-to-oil ratio (GOR) and the result of the calculation are calculated at standard conditions rather than actual conditions.

The EPA also proposed to add a definition for the term ''Associated gas venting or flaring'' to clarify what is included in this source. We are finalizing these amendments as proposed.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to associated gas venting and flaring. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: One commenter disagreed with the addition of the term ''$ERE_{p,q}$'' to equation W–18 for ''emissions reported elsewhere''. The commenter stated that including the term would significantly increase the burden, provide little increase in the accuracy of reported emissions, and, due to the difference in methods used to account for the equation parameters, may result in the calculation of negative volumes. The commenter recommended removing the term and revising the definition of the summation term for the equation to indicate that it applies to associated gas not reported elsewhere, consistent with the new definition for associated gas venting and flaring.

Response: The EPA included the term ''$ERE_{p,q}$'' in Equation W–18 of the proposed rule to harmonize with the proposed definition of ''associated gas venting or flaring,'' which was defined to exclude venting or flaring resulting from activities that are reported elsewhere, such as tank venting. Equation W–18 calculates associated gas emissions based on the gas-to-oil ratio (GOR) and volume of oil produced during the venting or flaring period. After considering the public comments, we determined that the potential for double-counting emissions using Equation W–18 with emissions reported elsewhere was minimal, particularly given the proposed definition of ''associated gas venting or flaring.'' For example, the EPA determined that the emissions as calculated using Equation W–18 are not expected to include or double-count emissions from onshore production storage tanks receiving oil from a separator at the wellhead. If onshore production storage tanks receive oil directly from the wellhead, these emissions are accounted for in the provisions for onshore production storage vessels, and these emissions would not constitute ''associated gas venting or flaring'' as defined in the proposal. Therefore, we concluded that the ''$ERE_{p,q}$'' term was not needed in Equation W–18. We are revising the proposed Equation W–18 to remove the ''$ERE_{p,q}$'' term, and we are finalizing the definition of ''associated gas venting or flaring'' as proposed.

10. Flare Stack Emissions

The EPA is finalizing revisions as proposed to simplify and clarify the calculation requirements for flare stack emissions in order to improve the accuracy of the collected data. As proposed, we are amending the calculation method for emissions from a flare stack to revise the calculations to standard conditions and to account for the fraction of emissions that are not combusted when sent to an unlit flare. The fraction of feed gas sent to an unlit flare is determined by using engineering estimates and process knowledge.

The EPA is finalizing amendments, as proposed, to include flare stack emissions to the list of sources for which emissions must be calculated for the onshore natural gas transmission compression, underground natural gas storage, LNG storage, and the LNG import and export equipment industry segments. The EPA did not receive major comments on these provisions and is not making any changes to the final rule as a result of public comments. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

11. Centrifugal and Reciprocating Compressors

a. Summary of Final Revisions

The EPA is finalizing amendments to the monitoring requirements for compressors with revisions to the proposed requirements. First, we are finalizing changes to the centrifugal and reciprocating compressor calculation sections (40 CFR 98.233(o) and (p)) to allow for the measurement of combined volumetric emissions from a manifolded group of compressor sources. In the proposed rule, reporters that had manifolded compressors were required to take at least three measurements per year and report the average of the measurements. In this final rule, we are requiring reporters to take a single measurement per year from manifolded compressors, which is commensurate with the measurement frequency for compressors that are not part of a manifold group of compressors. In the proposed rule, measurements from manifolded compressors were required to be taken before emissions are comingled with other non-compressor emission sources. We received comments that this requirement would often require new sampling ports in unsafe locations. In this final rule, we are changing this requirement to read as follows: ''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''.

The proposed rule inadvertently removed the use of acoustic device measurement for blowdown valve leakage for centrifugal and reciprocating compressors. It was not the EPA's intent to remove these provisions. As noted in the subpart W 2010 final rule and reiterated by commenters, the EPA has allowed the use of acoustic device measurement to address concerns regarding safety or inaccessibility issues for some vent measurements. As a result, we are allowing for quantification of emissions due to leaks from compressor blowdown valve leakage using an acoustic leak detection device. In this final rule, we are allowing the use of screening methods in 40 CFR 98.234(a) to determine whether quantitative emissions measurements are needed. We are finalizing the proposed reporting requirements for individual compressors and for manifolded compressors with minor changes intended to improve clarity.

We are also finalizing four definitions in 40 CFR 98.238 to support the addition of the calculation method for manifolded vents. We are finalizing the

definitions of ''compressor mode,'' ''manifolded compressor source,'' and ''manifolded group of compressor sources'' as proposed. The EPA received comments asserting that the fourth proposed definition for ''compressor source'' was unnecessarily vague. To address this concern, we are finalizing a revised definition of ''compressor source'' that includes detailed information regarding the types of emissions sources covered within the definition. We are finalizing the definition for ''compressor source'' to mean ''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, and wet seal oil degassing 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.''

For compressors that are routed to an operational flare, we are finalizing revisions as proposed to allow operators to calculate and report emissions with other flare emissions. As we proposed, reporters must still report certain compressor-related activity data for each compressor that is routed to an operational flare (as provided for in 40 CFR 98.236(o)(1) and (o)(2) and (p)(1) and (p)(2)).

The EPA is also finalizing several changes with regard to mode-specific measurements as proposed. We are finalizing as proposed the revisions to the requirements to measure each compressor in the not-operating-depressurized (NOD) mode at least once in any 3 consecutive calendar years provided that the measurement can be taken during a scheduled shutdown and, if there is no scheduled shutdown within three consecutive calendar years, the measurement must be made at the next scheduled depressurized compressor shutdown. We have included additional clarification in this final rule that a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available. We are not finalizing the proposed requirement to perform a measure for each operating mode once every three years.

We are also finalizing provisions, as proposed, that clarify that for reporters that elect to conduct ''as found'' measurements for individual compressor sources, all measurements from a single owner or operator may be used when developing an emission factor (using Equation W–24 or W–28 of 40 CFR 98.233) for each compressor mode-source combination. If the reporter elects to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator. Finally, we are restructuring and revising the centrifugal and reciprocating compressor sections (40 CFR 98.233(o) and 40 CFR 98.233(p)), as proposed, in order to improve clarity for reporters.

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to centrifugal and reciprocating compressors. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: Several commenters stated that the proposed rule did not address reporter concerns about measuring emissions from compressors. Several commenters requested that the EPA consider developing industry-wide emission factors to replace the current measurement-based approach in subpart W. One commenter requested that the EPA use data from outside studies and leverage the data collected from 2011 and 2012 to develop emissions factors and remove the annual measurement requirement after a reasonable timeframe. Another commenter requested that the EPA use emission factors that reflect the recently enacted New Source Performance Standards (NSPS) for the natural gas industry (40 CFR part 60, subpart OOOO). Two commenters suggested that reporter emission factors developed for individual compressors should be used when compressor sources are comingled with other non-compressor emission sources.

Response: The EPA appreciates the suggestions provided by the commenters and agrees that credible and accurate emission factors can provide a cost-effective means of calculating GHG emissions for purposes of reporting under Part 98. In particular, the EPA is willing to consider an emission factor approach under Part 98 for compressors.

As part of the development of the subpart W 2010 final rule, the EPA had previously considered using an emission factor approach for compressors. The EPA found that although a 1996 Gas Research Institute study on methane emissions from the natural gas industry provides much of the current knowledge on which emission factors from this sector are based, information on compressors was not necessarily reflective of current operational conditions for purposes of GHG reporting and therefore additional measurement data were needed in order to understand emissions related to specific modes of operation for compressors.

The EPA agrees that facilities have collected data under part 98 related to centrifugal and reciprocating compressors that can be used to inform an emission factor. However, the data which are inputs to emissions equations have not yet been reported to the EPA because they are deferred for reporting until 2015. The deferred reporting elements include the reporter-specific emission factors that are used to calculate emissions and the total time that a compressor is in a particular mode. The reporter-specific emission factors provide information on how measured data are applied to a reporter's other compressors that were not measured in a particular mode, and these factors are applied to all compressors for the total time each compressor is operated in each mode. Therefore the deferred data provide important information that could help inform the development of emission factors for each mode of operation. The EPA intends to analyze this deferred information after it is received in 2015. The EPA notes that the prevalence of BAMM in the reported data can affect cross-facility comparisons for developing emission factors, but the effect of BAMM cannot be fully analyzed until the inputs data are reported.

In addition, the data that will be reported under these final rule amendments will provide additional data that can inform the development of emission factors, such as information on the power output of the compressor driver. Furthermore, the compressor revisions that are being finalized in this rule will improve the quality of the reported data and address technical issues received from stakeholders during program implementation. The EPA also plans to review information that will be made available in the near future through outside studies.

The EPA is committed to working with stakeholders to review regulatory requirements, methods, and the quality of the information reported. The EPA looks forward to reviewing the deferred Part 98 data, data that will be reported under these revisions and data from

outside studies in order to determine if appropriate emission factors can be developed, and, if so, the EPA may revise the calculation and reporting requirements for compressors in a future rulemaking.

Comment: Several commenters objected to the requirements for measuring emissions from manifolded compressor sources. Two commenters asserted that the proposed rule fails to address issues that may preclude measurement from manifolded compressor sources (*e.g.,* unsafe to access and technically infeasible measurement locations, or vent gas from manifolded compressor sources that is comingled with gas from other emission sources) and two commenters noted that compressor vents are sometimes manifolded such that obtaining measurements of individual compressors is not possible; one of these commenters requested that these manifolded compressors be exempt from emissions measurements.

One commenter stated that the EPA has not addressed the burden associated with installing sampling ports on manifolded configurations. Another commenter objected to the proposed rule requirements specifying that manifolded compressor source emissions must be measured at a single point in the manifold downstream of all compressor inputs and where emissions cannot be comingled with other non-compressor emission sources; this commenter asserted that for compressor sources with emissions comingled with other sources, a sample port would need to be installed prior to the comingling of gases from the compressor sources and the non-compressor sources and could require the shutdown of all associated equipment.

Multiple commenters opposed the proposed requirements to conduct three measurements per year for manifolded compressors. One commenter claimed that the requirement to collect three measurements appears to be arbitrary and is not supported by 2011 or 2012 reported data. The commenter contended that the EPA has failed to explain how manifolded source-mode emissions data are expected to be different from other compressor source emissions data or why three measurements are expected to reduce measurement uncertainty associated with dissimilar measurements. Three commenters stated that the EPA did not address the cost and potential logistical problems associated with the mobilization of a test team two additional times per year (*i.e.,* total of three times a year) to conduct measurements on manifolded compressor sources. One commenter argued that the proposed requirements do not address concerns regarding the burden and costs associated with the installation of sample ports, or shutdown complications for port installation. One commenter argued that the EPA misrepresented the rule revision as a positive change beneficial to industry and a reduction in burden.

Response: The EPA disagrees with commenters who object to the need to independently categorize compressor source measurements from manifolded compressors; however, we acknowledge that some of the proposed clarifications inadvertently increased the stringency of the rule. The subpart W 2010 final rule included provisions that required the measurement of emissions from all vents, including emissions from individual compressors manifolded to common vents. The proposed rule changes do not alter that requirement and were intended to help current reporters to comply with subpart W.

The existing 2010 measurement requirements apply to the vent from the manifolded system without mention of co-mingled emission sources. We prefer and encourage measurements of manifolded compressors to be performed prior to co-mingling with other sources, as proposed. However, based on comments, we recognize that this may not be possible for certain installations. Therefore, we are not finalizing this provision as proposed. Instead, we are revising the requirement from the proposed rule so that the final rule reads as follows ''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''. We are also adding a reporting element for compressor measurements of manifolded systems to indicate whether the measurement location is prior to comingling with other non-compressor emission sources.

We proposed that reporters that had manifolded compressors be required to take at least three measurements per year and report the average of the measurements. In this final rule, we are requiring reporters to take a single measurement per year from manifolded compressors, which is commensurate with the measurement frequency for compressors that are not part of a manifolded group of compressors and consistent with the existing 2010 measurement requirements.

Comment: Three commenters requested that the EPA improve the definition of ''compressor source'' in 40 CFR 98.238 for clarity. One commenter contended that the proposed definition is not sufficiently clear to manage compliance and could lead to broad interpretation to sources not specifically called out in the rule. The commenter requested that the definition for ''compressor source'' be revised to specifically list the required sources.

Response: The EPA agrees with commenters that the proposed definition for ''compressor source'' could be read as potentially ambiguous and create confusion with regards to compliance with Part 98. Therefore, we are clarifying the definition of ''compressor source'' in this final rule to specify the applicability of the rule to specific compressor emission sources. We are finalizing the definition for ''compressor source'' to mean ''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, and wet seal oil degassing 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.'' These revisions clearly delineate the emission sources for which reporters must measure and account for emissions in the final rule.

Comment: Several commenters opposed the proposed requirements to measure compressors in the NOD mode once every 3 years, provided that a measurement can be taken during a scheduled shutdown. Three commenters requested that the EPA eliminate the requirement to measure compressors in the NOD mode in its entirety. One commenter argued that the proposed rule fails to provide sufficient justification to continue to require NOD mode measurements every three years. Another commenter argued that based on the monitoring data collected to date, the NOD mode compressor emissions are minimal, and the monitoring requirements are not cost effective. Another commenter stated that the measurements collected in 2011 and 2012 show that transmission and storage sources completed hundreds of measurements in the NOD mode, with about the same number of ''as found'' tests completed in shutdown mode as other modes.

Response: The EPA disagrees with commenters opposed to the proposed requirements to measure compressors in the NOD mode. The EPA established the requirements to measure compressors in the NOD mode once every 3 years as

part of the subpart W 2010 final rule. As the EPA previously noted (75 FR 18608, April 12, 2010), depending on operational practices, the various operating modes of centrifugal and reciprocating compressors may have significantly different emissions. The EPA noted at that time that unit isolation valves and compressor blowdown valves can have excessive leakage, especially when a compressor is not in operation. Following consideration of commenter input, the EPA finalized as part of the subpart W 2010 final rule these provisions to require measurements in the NOD mode once every 3 years.

The EPA reviewed the 2011, 2012 and 2013 reported emissions data for compressors and determined that compressor emissions from the NOD mode can contribute to a significant amount of the measured emissions for centrifugal compressors and reciprocating compressors. For more information, see the memorandum, ''Greenhouse Gas Reporting Rule: Technical Support for 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule'' in Docket Id. No. EPA–HQ–OAR–2011–0512. Therefore, we are not removing the requirement to measure emissions from compressors in the NOD mode in this final rule.

Comment: Several commenters stated that the EPA has not considered logistical issues in developing the requirements to measure compressors in the NOD mode once every 3 years, provided that a measurement can be taken during a scheduled shutdown. One commenter claimed that the proposed ''scheduled shutdown'' exception to the three-year requirement does not avoid the costs associated with mandatory testing in the NOD mode, such as out-of-sequence scheduling costs or the obligation to maintain records on compressor shutdown testing status. Two commenters stated that operators would likely force unit shutdowns while the measurement contractor is on site, which could result in the emissions of additional GHGs.

One commenter supported the proposed revision to allow the measurement to be taken during the next scheduled depressurized shutdown, however, the commenter asked that the scheduled shutdown not include instances when a scheduled compressor shutdown is only for a short duration, such that it is not possible to complete the measurement, or when a ''scheduled shutdown'' may occur without sufficient lead time to arrange for or mobilize a measurement team. Four commenters stressed that the proposed rule did not clearly define what constitutes a shutdown or ''scheduled shutdown.'' Another commenter noted that transmission compressors often start up and ''shutdown'' to meet demands; the commenter stated that it is not clear if this type of ''shutdown'' would be included under the proposed rule text. One commenter requested that the EPA provide a definition for the term ''scheduled shutdown'' that includes a shutdown of longer duration and likely associated with major maintenance and unit unavailability. Another commenter requested that the definition refer to a major maintenance outage that is scheduled months in advance, as opposed to a shutdown scheduled in direct response to a particular event (*e.g.,* in response to change in demand or operational disruption). One commenter argued that even if a scheduled shutdown refers to extended compressor shutdown for major maintenance, facilities would still face scheduling and logistical issues as well as increased costs.

One commenter responded to the EPA's request for comment on the option of requiring measurements in the NOD mode every five years rather than every three years. The commenter requested that the EPA extend the monitoring frequency to once every five years but noted that this change may not result in a unit being available at a specific time. The commenter suggested that emission factors be developed for the NOD mode as soon as feasible.

Response: The EPA is aware of commenter concerns regarding the need to shut down, purge, and blow down emissions from compressors in order to conduct emissions measurements. We are reducing the burden on facilities by augmenting the three-year measurement requirement to specify that reporters must take a measurement in the NOD mode within three years or at the next scheduled shutdown. If three consecutive calendar years occur without measuring the compressor in the NOD mode, then we are requiring that the NOD mode measurement must be made at the next scheduled depressurized compressor shutdown. We agree with commenters that indicated that the term ''scheduled shutdown'' was potentially nebulous and requires clarification. Therefore, we are clarifying in this final rule that a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. This may include maintenance such as replacement of compressor rod packing for reciprocating compressors or replacement of wet or dry seals in centrifugal compressors. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but remains available to meet increases in demand. These final revisions clarify that operators do not have to plan a shutdown of their equipment solely to take a measurement of their compressor in the NOD mode but may take the measurement as part of regular planned maintenance. These revisions also clarify that the compressor must be depressurized. These provisions will ensure that facilities have sufficient time to mobilize a test team and coordinate testing to occur during periods of planned shutdown. Therefore, this will reduce the need for reporters to schedule additional shutdowns outside of planned maintenance, reducing compliance costs. Although the EPA considered extending the period to collect measurements in the NOD mode to every 5 years, it would not necessarily alleviate reporter concerns regarding the need to schedule a shutdown solely for emissions measurements. As the EPA has previously noted in finalizing the subpart W 2010 final rule, three years is generally accepted as the period during which compressors would be shut down for regular maintenance. Therefore, we have determined that the final provisions provide an adequate extension for reporters for which the maintenance period extends beyond 3 years, while ensuring that the EPA collects the data in a timely manner as it comes available.

Comment: Two commenters objected to the proposed requirement to complete operating-mode measurements every three years or the next year that compressor operation exceeds 2,000 hours. These commenters stated that the EPA has not justified the need for or explained the benefit of this requirement in the proposed rule or the technical support document. Both commenters remarked that the subpart W measurement data currently reported includes hundreds of operating-mode tests completed within the first two years. One commenter stated that, at a minimum, the EPA should review and analyze 2011–2013 data to ascertain the need for such requirements. One commenter asserted that the proposed time interval has no basis. Two commenters stated that the proposed requirement would unnecessarily increase compliance costs in excess of EPA's presumed costs for completing measurements.

Multiple commenters requested that compressor measurements be completed

''as found'' without mandating mode-specific measurements. Three commenters noted that because the annual as-found measurements have already generated data in all three modes, further mode- and time-specific testing does not result in additional meaningful emissions data. The commenters urged that the proposed rule failed to justify the need for further mode- and time-specific testing requirements.

Response: The EPA proposed this change in order to ensure data for all compressor operating modes would be collected for all compressors. After considering comments and further reviewing the available reported data, the EPA concluded that additional mode specific measurements to ensure characterization of modes other than not-operating-depressurized mode are not necessary. Therefore, we are not finalizing the proposed requirement to perform a measure for each operating mode once every three years.

Comment: Five commenters objected to revisions in the proposed rule that appeared to eliminate the use of the acoustic method for blowdown valve leakage measurements for centrifugal compressors in operating-mode and for reciprocating compressors in operating mode or standby-pressurized-mode. The commenters noted that EPA had added a provision for leak rate quantification to the existing subpart W rule in response to comments on the re-proposed subpart W rule, in order to address concerns regarding safety or inaccessibility issues for some vent measurements. Commenters stated that the EPA had previously included this method to ensure safety in the collection of data from certain sources. One commenter noted that in the first three reporting years, many reporters have relied on the acoustic method for reciprocating compressor and centrifugal compressor measurements of isolation valve and blowdown valve leakage and condensate tank dump valve leakage. Several commenters requested that this method not be eliminated unless other alternative rule requirements, such as the use of an infrared camera for screening, are implemented.

Three commenters recommended that the EPA consider allowing the use of an infrared (IR) camera for screening vents that require measurement. These commenters requested that the rule include additional viable measurement methods and contended that an IR camera option would provide flexibility for reporters. One commenter noted that the IR camera could be used to screen for leaks from compressor isolation valves, blowdown valves, or rod packing released through a vent and identify whether vent measurement is needed. The commenter asserted that this method would be invaluable for screening vents that are unsafe or impractical to access. The commenter stated that several companies have received approval of BAMM requests to use the IR camera to screen these compressor sources for emissions.

Response: The EPA agrees with commenters that the acoustic device measurement method should not be eliminated from the final rule. During the revision of the centrifugal and reciprocating compressor calculation and monitoring requirements, the use of the acoustic device measurement for blowdown valve leakage for centrifugal and reciprocating compressors was erroneously removed. The EPA has previously allowed the use of acoustic device measurement to address concerns regarding safety or inaccessibility issues for some vent measurements, and we are aware that many reporters have relied upon acoustic device measurement to comply with the rule. The EPA understands the safety and inaccessibility concerns raised by commenters, and we did not intend to remove these provisions or to reduce flexibility for reporters in the proposed rule. In this final rule, we are maintaining provisions that allow for quantification of emissions due to leaks from compressor blowdown valve leakage using an acoustic leak detection device. Specifically, we have included these provisions in 40 CFR 98.233(o)(2)(i)(C) and 40 CFR 98.233(p)(2)(i)(C) of the final rule.

The EPA also agrees with the commenters' suggestion to allow for the use of optical gas imaging equipment or an infrared (IR) camera for compressor vent screening. The EPA has reviewed the methods in 40 CFR 98.234(a) and determined that these methods are appropriate for pre-screening for leakage from compressor vents. The use of an IR camera is currently allowed under subpart W to screen for dump valve leakage through tank vents in 40 CFR 98.233(k) and is a proven tool for identifying leakage from these emissions sources. Therefore, we have determined that it would be appropriate to allow the use of the methods in 40 CFR 98.234(a) for pre-screening of emissions from isolation valves, blowdown valves, or rod packing released through a vent, provided that sources conduct follow-up measurements if leaks are detected. The EPA agrees with commenters that this method would provide flexibility for reporters. We are finalizing provisions in 40 CFR 98.233(o)(2)(i)(D) and 40 CFR 98.233(p)(2)(i)(D) to allow the use of the methods in 40 CFR 98.234(a) to allow for pre-screening for leaks from compressor isolation valves, blowdown valves, or rod packing released through a vent. Reporters may use this method to identify whether further vent measurement is needed. If any emissions are detected, then reporters are required to use one of the methods currently specified in subpart W (acoustic leak detection device, calibrated bagging or high volume sampler, or temporary meter such as a vane anemometer) to quantify emissions. If no emissions are detected, the reporter would not be required to follow-up with a measurement to quantify emissions. We do not anticipate that these final revisions will negatively impact the quality of the data collected, as reporters will continue to use the existing measurement methods under subpart W to quantify emissions that are detected using the IR camera.

12. Natural Gas Distribution: Leak Detection Equipment and Emissions From Components

a. Summary of Final Revisions

The EPA is finalizing, with minor revisions from the proposed rule, amendments to revise Equations W–30A, W–30B, W–31, W–32A and W–32B to place the natural gas distribution facility meter/regulator run emission factors calculation in 40 CFR 98.233(q) instead of 40 CFR 98.233(r) while also clarifying that the emission factor is calculated separately for CO_2 and CH_4 and is on a meter/regulator run operational hour basis instead of a meter/regulator run component basis. The proposed rule inadvertently omitted appropriate provisions for calculating and reporting emissions from equipment leaks at above-grade transmission-distribution stations that are not surveyed during the reporting year as noted in the public comments received. Therefore, the EPA is finalizing minor revisions to Equations W–31 and W–32B as well as 40 CFR 98.233(q) introductory text, (q)(8)(ii) and (iii), and adding paragraph (q)(9) to specify how emissions from equipment leaks at above-grade transmission stations not surveyed during the reporting year are to be calculated. In the final rule, facilities must calculate annual emissions from above-grade transmission-distribution transfer stations surveyed during the calendar year using Equation W–30 of 40 CFR 98.233(q). The emissions are calculated in Equation W–30 on a per-component basis based on equipment leak survey results and emission factors for above-

grade transmission-distribution transfer station components listed in Table W–7. The results of the component-level annual emissions calculations using Equation W–30 are then used to develop the annual facility meter/regulator run population emission factors for CO_2 and CH_4 using Equation W–31. Paragraph 40 CFR 98.233(q)(8)(iii) was revised from proposal to provide more specificity on how the emission factors from Equation W–31 must be recalculated as additional equipment leak survey data become available from above-grade transmission-distribution transfer stations that use a multiple year equipment leak survey cycle. To calculate annual emissions from above-grade metering-regulating stations that are not above-grade transmission-distribution transfer stations and from all above-grade transmission-distribution transfer stations at facilities that use a multiple year equipment leak survey cycle must use the emission factors (calculated in Equation W–31) in the annual emissions calculation of Equation W–32B in 40 CFR 98.233(r). The primary difference from proposal is that the calculations for above-grade transmission-distribution transfer stations that elect to use a multiple year equipment leak survey cycle, which were inadvertently omitted, are now specified in the new paragraph at 40 CFR 98.233(q)(9). Completing the calculations for all above-grade transmission-distribution transfer stations allows for more unified reporting of the emissions for all above-grade transmission-distribution transfer stations 40 CFR 98.236(q).

As proposed, emissions from below-grade metering-regulating stations, below-grade transmission-distribution transfer stations, distribution mains, and distribution services are calculated using Equation W–32A of 40 CFR 98.233(r) using population emission factors listed in Table W–7.

The EPA is also finalizing the definition of ''meter/regulator run'' with minor revisions from the proposed rule. The revisions clarify that the term ''meter/regulator run'' refers only to components in the natural gas distribution industry segment. The final definition of ''meter/regulator run'' reads as follows: ''Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow, or both, in the natural gas distribution industry segment. At least one meter, at least one regulator, or any combination of both on a single run of piping is considered one meter/regulator run.''

b. Summary of Comments and Responses

This section summarizes the major comments and responses related to leak detection equipment and emissions from components for the natural gas distribution segment. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: One commenter noted that proposed text for 40 CFR 98.233(q)(8)(i) allows all distribution facility above-grade transmission-distribution transfer stations to be surveyed over multiple years up to a five-year cycle, while the emission calculation requirements of 40 CFR 98.233(q) and emission reporting requirements of 40 CFR 98.236(q)(2) only apply to equipment leaks at above-grade transmission-distribution stations surveyed during the reporting year. The commenter noted that emissions for equipment leaks at the above-grade transmission-distribution transfer stations not surveyed during the reporting year are not calculated or reported. The commenter suggested revising the associated text and equations to calculate these emissions using Equation W–32B and the emission factors calculated using Equation W–31.

Response: The commenter is correct that the proposed revisions inadvertently omitted provisions for calculating and reporting emissions from above-grade transmission-distribution transfer stations that were not surveyed in the first cycle of a multi-year cycle. In this final rule, natural gas distribution facilities may choose to conduct equipment leak surveys at all above-grade transmission-distribution transfer stations over multiple years, not exceeding a five year period. To account for annual emissions from above-grade transmission-distribution transfer stations that have not been surveyed in the current survey cycle (*i.e.,* whose emissions were not calculated using Equation W–30), we are revising the language proposed in 40 CFR 98.233(q)(8) and adding a paragraph (q)(9) to clarify that facilities must use the emission factors (calculated in Equation W–31) in the annual emissions calculation of Equation W–32B in 40 CFR 98.233(r). Additionally, we are revising the term ''$Count_{M,R}$'' in Equation W–32B to include meter/regulator runs at above-grade transmission-distribution transfer stations when required to be used according to the new paragraph at 40 CFR 98.233(q)(9). We are finalizing harmonizing edits to 40 CFR 98.236(q) and removing some reporting elements in 40 CFR 98.236(r) to clarify the applicability of the reporting requirements for equipment leaks at the above-grade transmission-distribution transfer stations and adding specific requirements for reporting elements when equipment leak surveys for above-grade transmission-distribution transfer stations are performed using multiple year cycles.

13. Calculation of GHG Emissions From Natural Gas Volume Emissions

a. Summary of Final Revisions

We are finalizing revisions as proposed to clarify onshore natural gas transmission compression, LNG storage, LNG import and export, and natural gas distribution facilities may use either site-specific composition or a default gas composition (95 percent CH_4 and 1 percent CO_2) to calculate GHG emissions from natural gas volume emissions at 40 CFR 98.233(u)(2)(iii), (v), (vi) and (vii). We are also finalizing analogous revisions to 40 CFR 98.233(u)(2)(iv) to clarify the option to use either site-specific composition data or a default gas composition (95 percent CH_4 and 1 percent CO_2) for underground natural gas storage facilities as well. The EPA requested comment on whether the use of site-specific composition data for calculating emissions should be required or optional. The EPA received comments supporting only the optional use of site-specific gas composition data; no commenters supported the mandatory use of site-specific gas composition data.

We are also finalizing several clarifications regarding the need to calculate emissions for certain equations in actual conditions based on public comments received. The EPA intended that the existing provision in 40 CFR 98.233(t) allowed for measurements to be made at standard conditions even when the equations specified actual conditions. However, we concluded that additional revisions could clarify this intent for reporters. First, we are finalizing revisions to the introductory text at 40 CFR 98.233 to read: ''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.'' Second, the introductory text at 40 CFR 98.236 is revised to read: ''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 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.''

b. Summary of Comments and Responses

Comment: Several commenters stated that requiring the conversion of gas flow rates from ''standard conditions'' to ''actual conditions'' when applying required estimation methodology is burdensome and overly complicated. These estimations then have to be converted back into standard conditions for reporting under the regulatory requirements. Since instrumentation used in the industry typically measures gas flow rates in standard conditions, the commenters requested the EPA to revise Equations W–3, W–4A, W–4B, W–7, W–17A, W–17B, W–34, W–39A, and W–39B to reflect that the measured gas volumes and/or estimated gas volumes used in these equations, and the resulting emissions, are in standard conditions to better meet reporting requirements and consistency.

Response: The EPA reviewed the existing provision in 40 CFR 98.233(t), which states that ''[i]f equation parameters in § 98.233 are already at standard conditions, which results in volumetric emissions at standard conditions, then paragraph (t) does not apply,'' and concluded that it effectively allows for measurement in either standard or actual conditions. However, in reviewing the calculation requirements in 40 CFR 98.233 and the reporting requirements in 40 CFR 98.236, we understand that additional clarity could be provided. We recognize that there are automated flow or volume measurement systems that automatically convert measurements to standard conditions. It was not our intent to require facilities to convert these data to actual conditions to fulfill the certain calculation and reporting requirements, then convert the volumes back to standard conditions prior to determining GHG mass emissions. We disagree with the commenters' suggestion that all of these equations should be expressed in standard conditions because not all facilities automatically correct the actual volumetric flow measured to standard conditions. Our intent was to provide an allowance to use either actual volumetric flow at the conditions present or volumetric flow corrected to standard conditions. In order to clarify this intent for reporters, we are finalizing revisions to the introductory text at 40 CFR 98.233 and 98.236 to clarify that use of systems that automatically correct to standard conditions is allowed. Specifically, the introductory text at 40 CFR 98.233 is revised to read, ''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.'' The introductory text at 40 CFR 98.236 is revised to read, ''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 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.''

Comment: Five commenters supported the option to use site-specific data while retaining the option to use the default methane and CO_2 composition values currently specified in subpart W. Four of these commenters stated that the use of site-specific composition data should not be mandatory. One commenter noted that compressor stations are normally not equipped with gas chromatographs for determination of site-specific gas composition; the commenter stated that mandatory reporting of site-specific gas composition would require the collection of extended gas analyses annually at each compressor station. Two commenters remarked that requiring mandatory use of site-specific composition data would result in increased costs and burden to reporters. Other commenters stated that the optional use of site-specific composition data adds flexibility for operators already using site gas quality data for other reporting purposes. Two commenters remarked that retaining the use of default composition values simplifies reporting without compromising GHG emission estimates for operators. These commenters noted that natural gas composition values downstream of natural gas processing facilities are much less variable than upstream operations.

Response: Paragraphs at 40 CFR 98.233(u)(2)(iii) through (vii) previously specified that these facilities ''may'' use the default composition, but they did not clearly specify the alternative to the default. In the proposed rule, we clarified that the alternative to the default was ''site specific engineering estimates based on best available data.'' The EPA specifically requested comment on whether the use of site-specific composition data for calculating emissions should be required or optional and solicited information on when a facility would not have site-specific composition data available. As the commenters noted, determining site-specific composition data based on measurement data would add burden to the industry, particularly where appropriate sampling and analysis equipment are not available. However, we note that the proposed language did not limit the site-specific composition to be based on site-specific measurement data, but rather ''site specific engineering estimates based on best available data.'' We agree with commenters that facilities should be allowed to use site-specific data when the data are available. We also agree with commenters that, when data are not available, the default values are reasonable alternatives for industries downstream of the processing plants. Therefore, after considering the information provided by commenters, the EPA is finalizing revisions in 40 CFR 98.233(u)(2)(iii) through (vii) to clarify that natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export, and natural gas distribution facilities may use either site-specific composition data (based on engineering estimates) or the default gas compositions.

14. Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions

1. Summary of Final Revisions

In this final rule, the EPA is clarifying that emissions and volume of fuel combusted must be reported for all internal combustion units that drive

compressors in 40 CFR 98.236. The EPA is revising this reporting requirement to be consistent with the emission estimation methods in 40 CFR 98.233(z)(4), which specify that the exemption from reporting emissions for internal combustion units with a rated heat input capacity less than or equal to 1 mmBtu per hour (130 hp) does not apply to internal fuel combustion sources that drive compressors. These revisions are finalized as proposed. We are also finalizing revisions to the description of the ''HHV'' term for Equation W–40 with minor revisions from the proposed rule. Specifically, we are finalizing that, for field gas or process vent gas, the reporter may use either the default higher heating value (HHV) or a site-specific HHV.

2. Summary of Comments and Responses

Comment: One commenter requested that the EPA modify the description of the term ''HHV'' used in Equation W–40 to allow the use of site-specific (measured) higher heating values for field gas or process vent gas, when the data are available, as an alternative to the currently specified default value. The commenter noted that allowing the use of site-specific HHV data would be similar to the proposed changes to allow site-specific GHG concentrations instead of default values.

Response: We agree with the commenter that the use of measured higher heating values should be allowed, when available. It was not our intent to mandate the use of the HHV default value but to allow its use when measurement data were not available. Therefore, we are finalizing the description of the ''HHV'' term in Equation W–40 to read as follows: ''Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For field gas or process vent gas, you may use either a default higher heating value of 1.235×10^{-3} mmBtu/scf or a site-specific higher heating value.''

C. Summary of Final Revisions to Missing Data Provisions

1. Summary of Final Revisions

The EPA is finalizing amendments to 40 CFR 98.235, with revisions from the proposed rule, to clarify the procedures for addressing missing data. We proposed various missing data procedures for different types or frequencies of measurement data. For AGR vents, we proposed that missing quarterly samples must use the average of the value of the last four quarterly samples. We received comments on how to implement this requirement when less than four quarters of data are available (*e.g.,* for new sources). Rather than establishing unique missing data procedures for this source, we are finalizing a requirement for these sources to use the ''before'' and ''after'' approach analogous to the missing data procedures proposed for continuous measurement data. Similarly, we are also finalizing, with minor revisions from proposal, the missing data requirements for measurement devices such as continuous flow monitors and composition analyzers to standardize these requirements to all measurements required by the rule except for annual measurement data. For stationary and portable combustion sources, we are finalizing amendments as proposed to require reporters to use the missing data procedures in subpart C of part 98.

As proposed, the EPA is finalizing amendments to allow the use of best engineering estimates for any parameter that cannot be reasonably measured or obtained according to the requirements in subpart W for up to 6 months from the facility's first date of subpart W applicability. We are also finalizing, with minor revisions from proposal, amendments to allow the use of best engineering estimates for any parameter that cannot be reasonably measured or obtained according to the requirements in subpart W for up to 6 months for facilities that are subject to subpart W and that acquire new sources from another facility that is not subject to reporting under subpart W. We originally proposed this amendment for new wells, but after reviewing the public comments received, we determined this allowance should be more broadly applied to any new emissions source acquired by the existing facility from another facility that is not subject to reporting under subpart W. Only data and calculations associated with those newly acquired sources fall under these provisions.

We are finalizing missing data provisions for annual and biannual (once every two year) measurements that are similar to the previous missing data requirements in 40 CFR 98.235 as provided in the subpart W 2010 final rule. These provisions require repeat of the estimation or measurement as soon as possible, with allowance to use measurements made after December 31 (in the subsequent year) as substitute values for the missing data in the reporting year.

We are not finalizing the reporting requirements for use of missing data procedures as proposed. In the proposed rule, we required missing data elements to be reported with significant specificity, including dates in which substitution values were used, equations in which the substitute value is used, a description of the circumstances that led to missing data, a description of the procedure used to develop the substitute value, the missing data procedure citation claimed, and a description of how missing data procedures will be avoided in the future. After reviewing public comments, we determined that reporting for missing data should more closely align with the requirements in other Part 98 source categories as guided by the requirements in 40 CFR 98.3(c)(8). We are finalizing reporting requirements to identify the data element for which missing data procedures were used and the number of hours (or required measurements) for which missing data procedures were used. We are also finalizing recordkeeping requirements regarding the use of missing data procedures to include some of the detail of the proposed reporting requirements. Specifically, reporters that use missing data procedures are required to keep a record listing the emission source type, a description of the circumstance that resulted in the need to use missing data procedures, the missing data provisions in 40 CFR 98.235 that apply, the calculation or analysis used to develop the substitute value, and the substitute value.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to missing data provisions. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: Several commenters recommended that if BAMM is eliminated as proposed, then the missing data provisions should be expanded to include all case-specific monitoring circumstances for which the EPA has previously reviewed and approved BAMM requests from 2011 through 2014, including (1) vent lines that cannot be safely or feasibly measured and where acoustic device measurement is not an option; (2) equipment and piping configurations that cannot be easily modified without incurring significant expense and operational delays; and (3) compressor measurement data in a specific mode.

Response: The EPA has considered the implications of removing BAMM requirements and commenters' concerns. Although the EPA indicated in the preamble to the proposed rule

that missing data procedures may provide clarity for reporters who may have unintentionally missed collecting required data, the missing data procedures are not intended to replace BAMM or to be used by reporters as BAMM. In the final rule, the EPA is finalizing multiple revisions to the rule that address commenter concerns related to BAMM. See Section II.D of this preamble for further discussion on BAMM.

Comment: Four commenters suggested that missing data procedures be expanded beyond ''activity data'' specified in 40 CFR 98.235(g) to include emissions from locations that are required to be directly measured and other data such as temperature and pressure. The commenters asserted there are situations where standard measurement procedures cannot be conducted and alternatives are necessary. These commenters asked the EPA to clarify whether activity data include the data elements similar to those used in Equation W–6 (*e.g.,* atmospheric pressure; pressure of the gas being discharged; percent of packed vessel volume that is gas; and the number of dehydrator openings in the calendar year). Other commenters asked that the missing data provisions specifically account for compressor vent and rod packing measurements. These commenters indicated it is not clear whether the EPA intended to include these measurements in 40 CFR 98.235(g).

Response: Activity data referred to in 98.235(g) includes data that are not measured, such as counts of the number of dehydrator openings in the calendar year. The provisions proposed in 40 CFR 98.233(g) were intended to cover only activity data values used in emissions calculations that could not be determined using the methods in 40 CFR 98.233; it does not refer to values that are required to be measured. In our proposed revisions of the missing data provisions, the EPA inadvertently omitted missing data procedures for measurements conducted annually, such as compressor measurements, or biannually, such as flow measurements of well venting for liquids unloading and flowback determinations for gas well venting during completions and workovers with hydraulic fracturing. It was our intent to maintain the existing missing data procedures for these data elements, which entails re-measurement of the emissions source. The EPA expects all reporters to comply with annual measurement requirements as specified in 40 CFR 98.233, unless the missing data provisions for new facilities or newly acquired sources apply. However, the EPA agrees with the commenters that missing data procedures are needed for the annual measurements to accommodate a variety of issues that may arise during sampling and analysis, including sample breakage during shipping, equipment malfunction during analysis. Therefore, we have included in this final rule specific missing data procedures for all estimation and measurements that are required to be performed annually or biannually. These provisions are the same as the previous missing data requirements in 40 CFR 98.235 as provided in the subpart W 2010 final rule. These provisions require repeat of the estimation or measurement as soon as possible, with allowance to use measurements made after December 31 (in the subsequent year) as substitute values for the missing data in the reporting year.

Comment: One commenter recommended a clarification of the missing data provisions for transmission storage tanks in 40 CFR 98.235(b). The commenter pointed out that although the provisions indicated that leakage for the entire year should be assumed, it does not provide a leak rate. The commenter suggested that the provisions allow for the use of a default rate equal to the leak rate threshold of 3.1 standard cubic feet (scf) per hour defined in 40 CFR 98.234(a)(5).

Response: The commenter is correct in noting that the measured emissions rate is critical to the calculation and that the proposed missing data procedures in 40 CFR 98.235(b) could be improved for calculating the emissions. The EPA disagrees that the default value of 3.1 scf per hour referenced by the commenter should be used. The value of 3.1 scf per hour in 40 CFR 98.234(a)(5) is the minimum level of a leak that can be detected with the acoustic leak detection device. If a leak is present, the leak can have a much higher flow rate than this value. In this case, assigning a default leak rate may grossly underestimate the emissions. As noted previously in this preamble section, the EPA has included in this final rule specific missing data procedures for all estimation and measurements that are required to be performed annually. These provisions require repeat of the estimation or measurement as soon as possible, with allowance to use measurements made after December 31 (*e.g.,* in the subsequent year) as substitute values for the missing data in the reporting year.

Comment: Some commenters suggested 40 CFR 98.235(e) should be revised to allow best engineering estimates for the first reporting year for facilities that become newly subject to subpart W. One commenter pointed out that a late year event (*e.g.,* unexpected blowdown in December) could result in a facility becoming newly subject to the rule. Two commenters asserted that 6 months was not sufficient and that a facility would require the use of best engineering estimates for the initial reporting year because the previously not subject facility would not have been collecting all data required for subpart W reporting. These commenters argued that these provisions should be available to both newly affected facilities and subject facilities with new emissions sources. Similarly, other commenters requested that 40 CFR 98.235(f) be broadened for all subpart W emission sources (rather than just wells) for the scenario where there is a change (*e.g.,* new source, new acquisition) at a subject facility, and the reporter cannot reasonably acquire necessary data. One commenter provided an example of adding new compression capacity on-line late in the year at a transmission or storage facility to meet demands in the winter months. The commenter stressed that it would be difficult and overly burdensome to require vent measurements from newly installed compressors. Another commenter requested that 40 CFR 28.235(f) be applicable to newly acquired wells whether or not the well was subject to subpart W previously.

Response: The EPA contends that 6 months is enough time for a newly subject facility to begin using the methods required in 40 CFR 98.233. The reporting rule general provisions at 40 CFR 98.2(h) recommend that facilities reassess applicability (including revising any relevant emissions calculations) whenever there is any change that could cause a facility to meet the applicability requirements of Part 98. Therefore, facilities which currently operate just under the reporting threshold for subpart W are aware of what changes would likely cause the facility to become subject to subpart W and should have an understanding of the calculation reporting requirements; although reporters may not be aware when an unexpected blowdown will occur, they would know whether an unexpected blowdown could cause them to be subject. The reporting rule general provisions at 40 CFR 98.3(b)(3) also state that if a facility becomes subject, the first annual report must cover the month during which the change that caused them to exceed the applicability limit occurred and the remainder of the year. Therefore, the facility does not

have to report measurements on the preceding months when no measurements were conducted. We have clarified 40 CFR 98.235(f) to specify that these missing data procedures apply to source types that were acquired from another company and were not previously subject to subpart W. These sources may require sampling ports to be installed or other modifications to accommodate measurements required in 40 CFR 98.233.

The EPA agrees that the proposed provisions in 40 CFR 98.235(e) and (f) should be extended to all subpart W emission sources, because issues that make it unreasonable to perform measurements for new wells may also exist for other subpart W emission sources. Therefore, we are finalizing these provisions to more broadly apply to ''sources'' rather than ''wells.''

The EPA disagrees that the proposed provisions in 40 CFR 98.235(f) should be extended to sources acquired from other companies that were previously subject to subpart W. The reporting rule general provisions in 40 CFR 98.4(h) provide for changes in owners and operators and provide that such owner or operator shall be responsible for the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier. Therefore, reporters are responsible for gathering data in a timely manner for acquired sources. Also, for sources acquired from companies that were previously subject to subpart W, any necessary sampling ports or other modifications would have previously been made to the equipment to accommodate measurement. Because facilities typically spend several months planning the acquisition and installation of new equipment, we anticipate that any issues can be addressed during this time, before the equipment begins to operate.

While we are not extending the missing data provisions proposed in 40 CFR 98.235(e) and (f) to facilities already subject to subpart W, we acknowledge that there are special cases where new compressors can be added to an existing facility and it may not be possible to perform an ''as found'' measurement of that new compressor source during the calendar year, for example, if the compressor is installed in late December. To address this issue, we have revised the proposed amendments for compressors at 40 CFR 98.233(o)(1)(i) and (p)(1)(i) to not require annual measurements of compressors installed after annual compressor measurements have already been conducted for all existing compressors at the facility. If not all of the existing compressors at the facility have been measured, then there is no additional burden associated with identifying and scheduling a testing crew for measuring the newly installed compressor. However, if a facility has already conducted their annual compressor measurements, requiring measurement of emissions for the newly installed compressor would impose a significant additional burden and may not be logistically possible within the calendar year. Therefore, in today's final rule, an annual measurement of a newly installed compressor would not be required if annual compressor measurements have already been conducted for all existing compressors at the facility. In this case, no missing data provisions are needed or are applicable for these newly installed compressors.

Comment: Several commenters took issue with the provisions in 40 CFR 98.235(h) and portions of related reporting requirements in 40 CFR 98.236(bb). The commenters objected to reporting a description of the unique or unusual circumstance that led to missing data use and a description of how the owner or operator will avoid the use of missing data in the future. The commenters argued that this would create an unneeded burden on reporters, go beyond the requirements of a reporting program, and are an overreach of the EPA's authority. Other industries subject to Part 98 are not required to this level of detail. One commenter also asserted that aggregation of missing data values is appropriate.

Response: Reporting elements for the missing data provisions are necessary for the EPA to understand what missing data substitute values were used; however, we agree with the commenter that the level of detail required in the proposed reporting requirements could become burdensome, especially for continuously monitored parameters. We reviewed the reporting requirements associated with the use of missing data procedures in the general provision 40 CFR 98.3(c)(8) and other subparts in Part 98. Although we disagree that the proposed missing data reporting requirements go beyond the requirements of a reporting program or is an overreach of the EPA's authority, we recognize that missing data can occur, such as due to calibration checks that indicate an instrument needs to be recalibrated. After considering the proposed reporting requirements in light of the comments received and the reporting provisions in other subparts, we determined that revisions were needed to the proposed missing data reporting requirements. In this final rule, we are requiring reporting of the use of missing data procedures following the general provision requirements in 40 CFR 98.3(c)(8), except we are providing for the reporting of number of times missing data procedures were used for an element that is not based on continuously monitored parameters.

Comment: One commenter noted that the missing data procedures proposed in 40 CFR 98.235(a) should be amended to accommodate new AGR vents that may not have four previously taken samples available. Another commenter indicated that 40 CFR 98.235(d) poses a problem where ''before'' or ''after'' values are not available for a data element that requires measurement. The commenter asserted that instances where a ''before'' or ''after'' value is not available for substitution require additional flexibility to enable compliance. The commenter provided, as an example, a situation where information from a third-party equipment operator, such as a third-party operated dehydrator, is not received and no data are available to substitute. The commenter also noted that there may be instances where a well completion in a sub-basin category/county/well-type combination is a single unique well and the measurement equipment necessary to measure flowback or calculate flowback malfunctions. The commenter argued that in this case, a reporter will not have ''before'' data to substitute.

Response: With respect to the missing data procedures for AGR vents, we agree with the commenter that additional clarification is needed, particularly to address new AGR vents that do not have four previous quarterly samples. In considering potential clarifications for the missing data procedures for AGR vents in light of the various scenarios of data availability, the missing data procedures for this source mirrored the procedures proposed in 40 CFR 98.235(d). Furthermore, we determined that the use of the average of a ''before'' and ''after'' sample would provide as good an estimate of the missing data as the average of four ''before'' samples. Therefore, we are generalizing the proposed missing data procedures in 40 CFR 98.235(d) to apply to all measurements that are required to be performed quarterly or more frequently.

The provisions proposed at 40 CFR 98.235(d) include specific provisions that can be used to determine the missing value in the absence of a ''before'' or ''after'' measurement. We find that the proposed procedures are reasonable for any data element that is

required to be monitored quarterly or more frequently. The proposed provisions of 40 CFR 98.235(d) are not meant to address measurement data that are required annually or biannually or situations such as the supply of information by third-party vendors. Reporters should know what information is needed for the annual reports. If reporters elect to use third-party vendors for certain services, the information needed for the annual reports may be specified in the third-party contract or agreement to ensure the necessary information is provided. We are not including any missing data provision in the final rule to allow for use of third-party operators that do not provide the required information needed for determining the emissions from dehydrators or other emissions sources.

D. Summary of Final Amendments to Best Available Monitoring Methods

1. Summary of Final Revisions

In this final rule, the EPA is removing all prior provisions in 40 CFR 98.234(f) for BAMM as proposed, but we are also adding transitional BAMM provisions for the 2015 calendar year after considering public comments. Specifically, we are revising 40 CFR 98.234(f) to provide short-term transitional BAMM for reporters who are subject to new monitoring or measurement requirements as part of these final amendments. Reporters have the option of using BAMM from January 1, 2015, to March 31, 2015, for certain parameters that cannot reasonably be measured according to the monitoring and QA/QC requirements of 40 CFR 98.234. Specifically, the transitional 2015 BAMM provisions cover the following data:

- Well-related measurement data that cannot reasonably be measured for well venting for liquids unloading and gas well venting during well completions and workovers with hydraulic fracturing, from wells not previously measured.
- Reciprocating compressor blowdown valve, isolation valve, and rod packing venting from manifolded vents, when conducting ''as found'' measurements according to revised 40 CFR 98.233(p)(4) or (p)(5).
- Centrifugal compressor blowdown valve, isolation valve, and wet seal oil degassing venting from manifolded vents, when conducting ''as found'' measurements according to revised 40 CFR 98.233(o)(4) or (o)(5).

For these parameters, reporters have the option to use BAMM from January 1, 2015, to March 31, 2015, without seeking prior EPA approval. Reporters will also have the opportunity to request an extension for the use of BAMM beyond March 31, 2015; those owners or operators must submit a request to the Administrator by January 31, 2015. The EPA is not providing transitional BAMM for these revised requirements beyond December 31, 2015. The provision of 3 months of automatic transitional BAMM will allow reporters to prepare for data collection while automatically being able to use BAMM, which is consistent with BAMM schedules in prior Part 98 rulemakings. This additional time for reporters to comply with the revised monitoring methods in subpart W will allow facilities to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions.

We are also removing and reserving 40 CFR 98.234(g). As described in the preamble to the proposed rule, we intended to remove and reserve this section but the removal of this section was not included in the regulatory text. These removed provisions are specific to the 2011 and 2012 reporting years, and the removal of this provision does not impact the reporting requirements for subsequent reporting years.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to best available monitoring methods. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: Three commenters supported the removal of BAMM for natural gas distribution facilities beginning in the 2015 calendar year. One commenter stated that replacing BAMM with explicit reporting requirements for petroleum and natural gas systems will reduce transaction costs, improve compliance, improve access to information about the oil and gas sector, and increase confidence in the rule. A second commenter believed that by clarifying the reporting emissions from natural gas distribution facilities, there should be no need to use BAMM after January 1, 2015. A third commenter pointed out that BAMM was originally a transitional tool, and other industry-specific subparts of Part 98 have eliminated BAMM. The commenter stated that the use of BAMM in 2012 created difficulties in comparing data across facilities and understanding discrepancies between GHG and other inventories. The commenter supported the addition of expanded missing data procedures and compliance pathways for facilities to use in the future. The commenter suggested that if operators require more flexibility than the ones EPA has proposed, that flexibility should be incorporated through a rulemaking effort rather than BAMM requests.

Eight commenters disagreed with the removal of BAMM beginning in the 2015 calendar year. Several commenters stated that eliminating BAMM would compromise compliance of impacted sources, especially in instances when it is not feasible to obtain a required measurement or where a direct measurement may be unsafe. These commenters requested the ongoing availability of BAMM or a revision of the missing data procedures for those instances where a reporter demonstrates a legitimate need.

Commenters pointed out that access to alternative methods is necessary for regulations. Some of the commenters pointed out that the EPA has allowed alternative compliance and monitoring methods in other regulatory programs (*e.g.,* NSPS in 40 CFR part 60, National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR part 63, and the Acid Rain Program in 40 CFR part 75) and urged the EPA to create a replacement, such as robust missing data provisions, for BAMM if it is eliminated. Other commenters stated that subpart W includes additional and more complex measurements than other Part 98 source categories. Some commenters expressed the importance of BAMM for sources that subsequently become subject to GHG reporting or where unpredictable future events occur. One commenter considered the flexibility of alternative methods to be important in the development of new technology and asked that the EPA should consider allowances in those cases. The commenter provided example scenarios in which the commenter stated that BAMM or an alternative method should be required, although the scenarios are not necessarily ''unique or unusual,'' such as vent lines that are unsafe to access and are unable to be assessed with an acoustic device, operating modes that are rarely used, and facilities where a late year addition of a new source precludes the ability to gather data.

Another commenter explained that future changes in operation or equipment may cause the facility to exceed the reporting threshold or create circumstances in which emission points meet the subpart W criteria, though that may not be known until the facility is surveyed. The commenter stated that

there may be time to resolve the situation before the monitoring deadline, but BAMM or a robust missing data provision would be needed. Two commenters asked that BAMM be allowed for newly acquired wells that were previously reported by prior owners and wells that have never reported, as both situations require the same level of effort to comply.

Three commenters requested at least a 6-month transitional BAMM following the final rule. The commenters requested adequate time to implement changes following the final rule. One commenter stated that a transitional BAMM of 6 months would allow flexibility to reporters, provide time for clarifications, allow for the development for the required systems, and accommodate issues regarding situations beyond the facility's control which require BAMM. Another commenter stated that developing processes for monitoring data or activities that have never before been subject to federal or state reporting may take significant time and effort. The commenter pointed out that until the final rule has been issued, reporters will not be able to determine what is required and will not know if BAMM is needed. Another commenter stated that if BAMM is not extended, small operators without the resources to quickly implement the rule would be unfairly disadvantaged.

Response: The EPA has considered the concerns raised by commenters in the development of this final rule. We are removing the prior BAMM requirements in 40 CFR 98.234(f) because we have determined that these provisions, which applied broadly to circumstances in which data collection methods did not meet safety regulations, were technically infeasible, or were counter to state, local, or federal regulations, are no longer necessary to comply with the final rule. As one commenter noted, BAMM was originally included in Part 98 as a transitional tool, and all other industry-specific subparts of Part 98 have eliminated BAMM from their monitoring options. The revisions in this final rule will resolve the need for BAMM for the scenarios mentioned above for subpart W and can, therefore, bring this subpart into alignment with the monitoring provisions in other industry-specific subparts by removing the current BAMM provisions. In the development of this final rule, the EPA reviewed BAMM request submittals for the 2014 reporting year. In our review, the EPA found that the sources with the most frequent BAMM requests included centrifugal compressors, reciprocating compressors, blowdown vent stacks, and combustion emissions, which are addressed in this rulemaking. The most common concerns raised in BAMM requests were associated with technical infeasibility including concerns related to having to shut down a facility to install access ports to conduct compressor measurements. Other concerns related to compressors routed to a flare, manifolded lines, and compressor vents that were unsafe or inaccessible to measure. As discussed in Section II.B.10 of this preamble, we are making several revisions in this final rule that will allow for the testing of these compressor vents. First, we are clarifying that operators do not have to shut a facility down for the sole purpose to test a compressor in its non-operating mode, but that the measurement must be made at the next scheduled shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. These provisions reduce the burden on reporters to schedule a shutdown solely for the purposes of conducting measurements. The EPA has also provided the option for facilities to conduct continuous measurements using a permanent meter. Next, we are providing for reporters to conduct a single annual ''as found'' measurement for manifolded compressors routed to a common vent, in lieu of a measurement for each individual compressor manifolded to the common vent. We are also allowing the use of an IR camera for pre-screening of emissions from blowdown valves on compressors in operating mode or standby-pressurized mode and for isolation valves on compressors in not-operating-depressurized mode. The option to use an IR camera to screen for emissions, in addition to the current allowance for use of an acoustic measurement device, eases the burden on facilities with inaccessible or unsafe-to-measure valves. Finally, for compressors routed to a flare, we are finalizing provisions to allow operators to calculate and report emissions with other flare emissions. In this case, reporters are no longer required to sample compressors routed to a flare individually.

The EPA is also addressing the most common scenarios for which BAMM was previously requested for other emission sources. For example, for blowdown vent emissions, the EPA previously approved BAMM requests for reporting data by unique physical volume. In this final rule, we are revising the reporting of blowdown emissions to aggregate emissions by equipment type, as discussed in Section II.B.6 of this preamble. Similarly, for well venting for liquids unloading, the final rule allows for annualizing of venting data to account for situations where it was not feasible to gather vent hours or the number of unloadings from all controllers on January 1 or December 31, and it provides alternatives to determining the shut-in pressure required in Equation W–8. We have incorporated revisions in this final rule to address BAMM concerns for onshore production tanks and well completions and workovers. Additionally, we are finalizing missing data procedures that add clarity and specificity in how to treat and report missing data, including continuous measurements, periodic measurements and activity data. These missing data procedures are not intended to replace BAMM, however, they provide clarity for reporters who may have unintentionally missed collecting required data. These missing data procedures would also apply to facilities for which changes in operation or equipment may cause the facility to exceed the reporting threshold or result in creating circumstances in which emission points meet the subpart W criteria, as well as for newly acquired sources that were not previously reported under subpart W. We also note that there have been previous BAMM requests in which facilities noted technical concerns including instances where equipment modifications or installations were necessary. By the 2015 reporting year, facilities will have had four years to implement any necessary changes in order to fully comply with subpart W, which we have determined to be sufficient time to make any equipment modifications or installations. Therefore, we are not including BAMM provisions for these scenarios in this final rule.

Regarding the comment that other regulatory programs allow alternative compliance and monitoring methods, the EPA acknowledges that the provisions of NSPS and NESHAP allow facilities to request alternative monitoring and testing methods. However, the NSPS and NESHAP provisions typically require that specific monitoring methods be used (*e.g.* EPA Method 18 for gas compositional analysis), and they do not allow facilities to use alternative monitoring and testing methods without the method first being approved by the EPA. The EPA has provided a great deal of flexibility in the methods allowed in subpart W, such as certain provisions that allow the use of standard methods published by consensus-based standard organizations and that allow the use of

industry standard practice. Given the flexibility in the methods allowed under Part 98, we do not agree with the commenters.

Although we are removing the current BAMM provisions of 40 CFR 98.234(f), the final rule introduces new short-term transitional BAMM provisions for certain parameters for the 2015 calendar year. The EPA agrees with commenters that some facilities may need to obtain the necessary equipment to conduct measurements as required under the revised calculation methods in this final rule. Thus, under the final rule, reporters have the option of using BAMM for certain parameters that cannot be reasonably measured according to the monitoring and QA/QC requirements of 40 CFR 98.234. For example, we are revising the emission estimation methods for well completions and workovers from wells with hydraulic fracturing to separate reporting by well completions and workovers and by the sub-basin and well-type combination. In some cases, we expect reporters will be required to measure existing wells of a well-type combination for which they have not previously reported separately. In this case, reporters have the option to use BAMM for well-related data (*i.e.,* initial and average flowback rates for Calculation Method 1 or pressures upstream and downstream of the choke for Calculation Method 2). Other situations where the final rule provides an option to use BAMM in the 2015 calendar year are for determining vented gas flow when using Calculation Method 1 to estimate emissions from liquids unloading, and for determining vented emissions from compressor sources that are manifolded.

In some cases, although we are revising emissions calculation methods in the final rule, we are not providing the BAMM option because the underlying measurement methods have not changed. For example, although we have separated the calculation of emissions from completions and workovers from wells without hydraulic fracturing in 40 CFR 98.233(h), reporters are still collecting the same well data and measurements. We are not providing BAMM in this case or in similar cases where reporters would not be required to change their data collection methods.

We are not providing the BAMM option for parameters in revised calculation methods where the rule already provides alternatives to direct measurements. For example, the final rule requires facilities in the onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import export industry segments to report emissions from flares based on using the calculation methods for flare stacks. BAMM is not needed in this case because 40 CFR 98.233(n)(1) specifies that flare gas flow may be estimated using engineering calculations based on process knowledge, company records, and best available data. Similarly, 40 CFR 98.233(n)(2) specifies that as an alternative to using a continuous gas composition analyzer on the flare gas, a reporter in the four industry segments now required to report flare emissions may use a representative composition determined by engineering calculation based on process knowledge and best available data. The BAMM option also is not being provided for activity data such as completion or workover counts and venting or operating time because the final rule does not specify monitoring equipment that must be used for measuring these parameters.

The final rule allows reporters to use BAMM for the specified parameters during the January 1, 2015 to March 31, 2015 time period without seeking prior EPA approval. By automatically allowing BAMM until March 31, 2015, this schedule allows additional time following the publication of the final rule for reporters to prepare for data collection and install the necessary monitoring equipment. The final rule also provides for reporters the option to request an extension for the use of BAMM beyond March 31, 2015, but no further than December 31, 2015. Reporters who request an extension must submit a request to the Administrator by January 31, 2015, and demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2015, to receive approval to use BAMM beyond March 31, 2015. In these cases, the Administrator will only approve BAMM for the parameters specified in Section II.D.1 of this preamble. We anticipate that the number of BAMM requests approved for the 2015 calendar year will be limited and will not greatly impact the quality of the data collected in 2015.

E. Summary of Final Additions of New Data Elements and Revisions to Reporting Requirements

1. Summary of Final Revisions

We are finalizing the addition of several data elements to 40 CFR 98.236, with revisions from the proposed rule based on review of comments and other considerations. Although the EPA received comments objecting to the proposed addition of these data elements, these new data elements are based on data that are already collected by the reporter or are readily available to the reporter. The reporting of these data elements will improve the quality of the data reported, improve the verification of reported emissions, and reduce the amount of correspondence with reporters that is associated with follow-up and revision of annual reports.

After proposal, we determined that some proposed data elements could be removed to lessen reporter burden. For offshore production facilities, the final rule requires reporting of the total quantity of oil handled at the offshore platform, which includes the quantity from blended oil/condensate streams; this reporting element replaces the proposed requirements to report the amount of oil and the amount of condensate separately. Additionally, we are not finalizing the proposed requirements to report the model name, description, and installation year for each compressor.

As a result of comments received on the proposed rule, we are adding requirements to report two data elements for centrifugal and reciprocating compressors. Affected facilities with centrifugal or reciprocating compressors will be required to indicate whether the measured volume of flow from the compressor includes blowdown emissions, according to 40 CFR 98.236(o)(4)(iii) and 40 CFR 98.236 (p)(4)(iii), respectively.

2. Summary of Comments and Responses

This section summarizes the major comments and responses related to the addition of new reporting requirements in 40 CFR 98.236(aa). See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: One commenter questioned the proposal's requirements to report information that does not address emissions but instead requires ancillary information such as compressor ratings. The commenter considered these new measurement and reporting requirements to go beyond the authority of the EPA under CAA Sections 114 and 208, making the changes arbitrary and capricious if finalized. The commenter considered the proposed reporting requirement changes to be an overreach for an emissions reporting program and points out that 40 CFR 98.236(aa) in particular appears to be using Part 98 as a vehicle to construct detailed profile of

the oil and gas production sector. The commenter considered the proposed changes to unnecessarily expand the measurements and reporting requirements from the existing Part 98 and points out examples.

Multiple commenters provided examples of data elements that they stated are not within the scope of Part 98 because they are not directly related to emissions quantification or are redundant: For transmission storage tank vent stack, whether scrubber dump leakage is occurring for the underground storage vent—§ 98.236(k)(l)(iii); year compressor was installed—§ 98.236(p)(1)(xiv); compressor model name and description—§ 98.236(p)(1)(xv); date of last rod packing—§ 98.236(p)(1)(xvi); average time surveyed components were found leaking and operational—§ 98.236(q)(2)(iii); average upstream pipeline pressure, psig—§ 98.236(aa)(4)(iv); average downstream pipeline pressure, psig—§ 98.236(aa)(4)(v); quantity of gas injected into storage—§ 98.236(aa)(5)(i); quantity of gas withdrawn from storage—§ 98.236(aa)(5)(ii); number of compressors—§ 98.236(aa)(4)(ii); total compressor power rating for all compressors combined, hp—§ 98.236(aa)(4)(iii); and total storage capacity for underground natural gas storage facilities—§ 98.236(aa)(5)(iii).

One commenter stated that the EPA should explain or justify the need for addition of these data elements. Multiple commenters stated that the new reporting requirements are not relevant for quantifying emissions and developing this information in order to report represents a substantial burden.

Response: The EPA disagrees with commenters that the proposed data elements are beyond the authority of the EPA under CAA section 114. CAA section 114 authorizes the EPA to gather the information under this rule. Specifically, section 114 provides for the gathering of information from direct sources of GHG emissions, as long as that information is for purposes of carrying out any provision of the CAA. CAA section 208 applies to mobile sources, which are not covered by subpart W.

The additional reporting requirements included in this final rule provide production, capacity, and operational information for sources subject to subpart W and are similar to the data collected under other subparts of Part 98. These data elements are useful for the verification of existing data. For example, production, capacity, or operational information may be used to normalize the data collected and adequately characterize emissions sources. Therefore, the EPA is finalizing these reporting requirements as proposed, with minor clarifications. Further information on the final changes to the reporting section may be found in the memorandum, ''Final Revisions to the Subpart W Reporting Requirements in the ''Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule'' in Docket Id. No. EPA–HQ–OAR–2011–0512.

III. Confidentiality Determinations

A. Summary of Final Confidentiality Determinations for New or Revised Subpart W Data Elements

In the proposed rule, we assigned new or revised data elements to the appropriate direct emitter data categories created in the 2011 Final CBI Rule based on the type and characteristics of each data element. For data elements the EPA assigned to a direct emitter category with a categorical determination, the EPA proposed that the categorical determination for the category be applied to the proposed new or revised data element. For data elements assigned to the ''Unit/Process 'Static' Characteristics that Are Not Inputs to Emission Equations'' and ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' we proposed confidentiality determinations on a case-by-case basis taking into consideration the criteria in 40 CFR 2.208, consistent with the approach used for data elements previously assigned to these two data categories. We also proposed individual confidentiality determinations for 11 new or substantially revised data elements without making a data category assignment and we proposed to revise the confidentiality determination for one existing subpart W data element. Refer to the preamble to the proposed rule (79 FR 13394, March 10, 2014) for additional information regarding the proposed confidentiality determinations.

With consideration of the data provided by commenters, the EPA is finalizing the confidentiality determinations as proposed for all but 7 of the new and substantially revised data elements that were proposed. Specifically, the EPA is finalizing the proposed decision to require each of the new data elements and the one existing data element for which we revised the confidentiality determination be designated as ''not CBI'', with the exception of seven new data elements for which we have subsequently identified potential confidentiality concerns, as discussed in this section. The seven data elements with revised confidentiality determinations apply to onshore natural gas plants and natural gas transmission facilities.

For onshore natural gas plants, the EPA has revised the determination for the following four data elements: The quantity of natural gas received at the gas processing plant in the calendar year (reported under 40 CFR 98.236(aa)(3)(i)), the quantity of processed (residue) gas leaving the gas processing plant (reported under 40 CFR 98.236(aa)(3)(ii)), the quantity of natural gas liquids (NGL) (bulk and fractionated) received (reported under 40 CFR 98.236(aa)(3)(iii)), and the quantity of NGL (bulk and fractionated) leaving the plant (reported under 40 CFR 98.236(aa)(3)(iv)). In the proposal, we indicated that we designated the annual quantity of natural gas received at a gas plant and the annual quantity of residue gas leaving a gas plant to be ''not CBI'' because the average annual flow and plant utilization rate are published on the Energy Information Administration's (EIA's) Web site and are already in the public domain. However, upon reexamination we determined that reporting to EIA of the amount of natural gas received is less frequent than that required under subpart W and we have not identified any reliable public sources of the quantity of residue gas produced. Thus, we have decided to maintain the annual quantity of natural gas received at gas plants and the annual quantity of processed (residue) gas leaving gas plants as confidential.

We indicated in the proposal that the two NGL data elements were aggregated values for all NGL received and all NGL supplied by a natural gas processing plant. We also explained that this information would not cause competitive harm to reporters because the data for individual NGL products (which would be likely to cause competitive harm) would not be disclosed. While most plants receive and supply several different NGL products, we have identified a few plants that receive and/or supply only one NGL product. For example, some plants remove only ethane from the natural gas received. For this subset of plants, the quantity to be reported under subpart W is identical to the quantity reported under subpart NN, which the EPA determined to be CBI (see 76 FR 30782, May 26, 2011). Thus, the EPA has decided not to make a confidentiality determination for 40 CFR 98.236(aa)(3)(iii) and (aa)(3)(iv).

The confidentiality status of these data elements will be evaluated on a case-by-case basis, in accordance with the existing CBI regulations in 40 CFR part 2, subpart B, upon receipt of a public request for these data elements.

For the natural gas transmission sector, the EPA has revised the confidentiality determination in this action for three data elements: The quantity of gas transported through a compressor station (reported under 40 CFR 98.236(aa)(4)(i)) and the average upstream and downstream pressures (reported under 40 CFR 98.236(aa)(4)(iv) and (v), respectively). We proposed that these data elements be designated as ''not CBI.'' We noted that the natural gas transmission sector was heavily regulated by the Federal Energy Regulatory Commission (FERC) and state commissions due to a lack of competition between companies. We further noted that FERC controls pricing, sets rules for business practices, and is responsible for approving the location, construction, and operations of companies operating in this sector. However, we received comments from this industry sector noting that FERC Order 636 had introduced greater competition to this sector and that some companies charge customers less than the FERC approved rates because of competitive market pressures. The three data elements identified above would provide information on the quantity of gas transported by a specific pipeline. This information may potentially cause competitive harm to some pipeline companies operating in more competitive market areas. Since the determination would depend on the particular market conditions for each company, the EPA was not able to make a determination for these data elements that would apply for all reporters. Thus, the EPA has decided not to make a confidentiality determination for 40 CFR 98.236(aa)(4)(i), (iv) and (v). The confidentiality status of these data elements will be evaluated on a case-by-case basis, in accordance with the existing CBI regulations in 40 CFR part 2, subpart B, upon receipt of a public request for these data elements.

The EPA received several comments questioning the proposed determination that several new or revised data elements should be treated as non-confidential. Specifically, we received comments requesting that the EPA classify certain data elements associated with exploratory wells (delineation and wildcat wells) as CBI for a period of at least 24 months from the start of exploration. These comments and the EPA's responses are summarized in Section III.B of this preamble. Based on consideration of these comments and consistent with the EPA's previous decisions related to exploratory wells under Part 98 (79 FR 63750, October 24, 2014), the EPA is revising the final rule to provide reporters with the option to delay reporting of 12 data elements for two reporting years in situations where exploratory wells are the only wells in a sub-basin. For a given sub-basin, in situations where wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the required measurement, the following data elements associated with the delineation or wildcat well may be delayed for two reporting years: (1) Cumulative flowback time for each sub-basin (40 CFR 98.236(g)(5)(i)); (2) measured flowback rate for each sub-basin (40 CFR 98.236(g)(5)(ii)); (3) average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring (40 CFR 98.236(h)(1)(iv)); (4) average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring (40 CFR 98.236(h)(2)(iv)); (5) if using Calculation Method 1 or 2 for atmospheric storage tanks, the total annual gas-liquid separator oil volume that is sent to atmospheric storage tanks in the sub-basin, in barrels; (6) if using Calculation Method 3 for atmospheric storage tanks, the total annual oil throughput that is sent to atmospheric tanks in the basin (40 CFR 98.236(j)(2)(i)(A)); (7) if oil well testing is not performed where emissions are not vented to a flare, the average flow rate in barrels of oil per day for well(s) tested (40 CFR 98.236(l)(1)(iv); (8) if oil well testing is performed where emissions are vented to a flare, the average flow rate in barrels of oil per day for well(s) tested (40 CFR 98.236(l)(2)(iv)); (9) if gas well testing is performed where emissions are not vented to a flare, average annual production rate in actual cubic feet per day for well(s) tested (40 CFR 98.236(l)(3)(iii)); (10) if gas well testing is performed where emissions are vented to a flare, average annual production rate in actual cubic feet per day for well(s) tested. (40 CFR 98.236(l)(4)(iii)); (11) volume of oil produced in the calendar year during the time periods in which associated gas was vented or flared (40 CFR 98.236(m)(5)); and (12) total volume of associated gas sent to sales in the calendar year during time periods in which associated gas was vented or flared (40 CFR 98.236(m)(6))).

Six of the 12 data elements for which reporting may be delayed by 2 years are inputs to emission equations and the EPA provided the same option in the EPA's previous decisions related to exploratory wells under Part 98 (79 FR 63750, October 24, 2014). Five of the 12 data elements are inputs only when the applicable data are related to a single well (40 CFR 98.236(g)(5)(i), (h)(1)(iv), (h)(2)(iv), (m)(5), and (m)(6)), and one data element is never an input (40 CFR 98.236(j)(2)(i)(A)). The EPA decided to treat all early disclosure concerns related to exploratory wells consistently throughout subpart W by providing the option to delay reporting by 2 years to all 12 data elements. For the six data elements that are not always inputs, the finalized confidentiality determinations of ''not CBI'' apply in situations where the data elements are not an input to an equation. Specifically, the ''not CBI'' determination applies to all situations that involve multiple non-exploratory wells or a mix of exploratory and non-exploratory wells, and the ''not CBI'' determinations also will apply to data elements related to multiple exploratory wells once the data are reported to the EPA following the 2 year delay. For the situations when the data elements are used as inputs to equations, the EPA is assigning them to the ''Inputs to Emission Equations'' data category and is not making confidentiality determinations for these data.

In response to public comments, the EPA has added eight new data elements related to compressors as reporting requirements and has assigned them to the ''Unit/Process 'Static' Characteristics That Are Not Inputs to Emission Equations'' data category. Two of the new data elements require reporters to indicate whether compressor blowdown emissions are included in the measured volume of flow from compressor sources that are monitored continuously. Four of the new data elements require reporters to indicate whether measurements for manifolded groups of compressor sources are located prior to or after comingling with non-compressor emissions. These six data elements apply to both centrifugal compressors and reciprocating compressors, and they are located in 40 CFR 98.236(o)(3)(i)(F), (o)(4)(iii), (o)(4)(iv), (p)(3)(i)(F), (p)(4)(iii), and (p)(4)(iv). For each centrifugal and reciprocating compressor equipped with blind flanges, the other two new data elements require reporters to provide the dates when the blind flanges were in place, and these elements are located in 40 CFR 98.236(o)(1)(x) and (p)(1)(xii). All eight of the new data elements are the same type of data as other data elements included in this category in

the March 2014 proposal such as the data element that requires reporters to indicate whether any compressor source emissions are routed to a flare. Like other data elements in this category, the new data elements do not vary with time or with the operation of the compressor. Additionally, the new data elements describe only an aspect of the compressor design and emissions handling technique that reveals no sensitive information that would be likely to cause substantial harm to any type of natural gas facility. The March 2014 proposal addressed the same type of data elements. We conclude that it is appropriate to assign the data elements to this data category and finalize our determination that these data elements are ''not CBI'' in this action.

The EPA has determined that we inadvertently omitted proposing confidentiality determinations for 12 new data reporting elements. The measured scrubber dump valve leak rate vented directly to atmosphere (40 CFR 98.236(k)(2)(ii)), the measured scrubber dump valve leak rate vented to flare (40 CFR 98.236(k)(3)(ii)), and the annual CO_2 and CH_4 emissions from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations (40 CFR 98.236(r)(2)(v)(A) and (r)(2)(v)(B), respectively) are data representing emissions to the atmosphere. The March 2014 proposal addressed numerous similar elements and assigned them to the ''Emissions'' data category, which has a categorical confidentiality determination of ''not CBI.'' We conclude that it is appropriate to assign the four previously omitted data elements to the ''Emissions'' data category and finalize our determination that these data elements are ''not CBI'' in this action.

Five of the new data elements for which we did not propose confidentiality determinations in the proposed rule are similar to data elements that were assigned to the ''Unit/Process Operating Characteristics That are Not Inputs to Emission Equations'' data category. For example, the type of control device for emissions from glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscf per day (40 CFR 98.236(e)(2)(iii)) is the same as the data element in 40 CFR 98.236(e)(3)(i) for reporting the type of control device used to control emissions from dehydrators that use desiccant. The number of atmospheric tanks in the sub-basin that did not control emissions with flares (40 CFR 98.236(j)(2)(ii)(B)) and the number of atmospheric tanks in the sub-basin that controlled emissions with flares (40 CFR 98.236(j)(2)(iii)(B)) are comparable to the data elements in 40 CFR 98.236(e)(2) and (e)(3) for the counts of dehydrators that vent to atmosphere, flare, vapor recovery, or other types of control devices. The duration of time that a scrubber dump valve leak occurred (40 CFR 98.236(k)(2)(iii)) and the duration of time that flaring of a scrubber dump valve leak occurred (40 CFR 98.236(k)(3)(iii)) are comparable to the data element in 40 CFR 98.236(j)(3)(ii) for the total time that dump valves on gas-liquid separators did not close properly. Furthermore, as we noted in the discussion of the confidentiality determination for 40 CFR 98.236(j)(3)(ii) in the preamble to the proposed rule, because the time period during which a dump valve is malfunctioning provides little insight into maintenance practices or the nature or cost of repairs that are needed, public disclosure of such information would not be likely to cause substantial competitive harm to reporters. The finalized confidentiality determinations for all of the data elements that are comparable to the five data elements that were inadvertently omitted from the analysis at proposal are ''not CBI.'' We conclude that it is appropriate to assign the five previously omitted data elements to the ''Unit/Process Operating Characteristics That are Not Inputs to Emission Equations'' data category and finalize our determination that these data elements are ''not CBI'' in this action.

Three of the new data elements for which we did not propose confidentiality determinations in the proposed rule are identical to other data elements that were included in the analysis at proposal. The centrifugal compressor name or ID (40 CFR 98.236(o)(2)(i)(A)), the centrifugal compressor source (40 CFR 98.236(o)(2)(i)(B)), and the unique name or ID for the leak or vent (40 CFR 98.236(o)(2)(i)(C)) are identical to the corresponding data elements for reciprocating compressors in 40 CFR 98.236(p)(2)(i)(A), (p)(2)(i)(B), and (p)(2)(i)(C). These data elements for reciprocating compressors were assigned to the ''Facility and Unit Identifier Information'' data category, and the final confidentiality determination for these data elements is ''not CBI.'' We conclude that it is appropriate to assign the three previously omitted data elements to the ''Facility and Unit Identifier Information'' data category and finalize our determination that these data elements are ''not CBI'' in this action.

As discussed in Section II.B.5 of this preamble, the final rule clarifies the reporting requirements for the time variable used in Equation W–10A (40 CFR 98.236(g)(5)(i)). Specifically, the final rule requires reporting of both cumulative gas flowback time values used in the revised Equation W–10A (''$T_{p,i}$'' and ''$T_{p,s}$''), whereas the proposed rule inadvertently retained the current reporting of the single value that is used in Equation W–10A from the subpart W 2010 final rule. At proposal, the data element was determined to be an input. However, it is an input only when one completion or workover has been conducted in a particular sub-basin and well type combination category. When data for completions or workovers for multiple wells are included in the calculation, it is a data element for which a confidentiality determination is required. The final data elements in 40 CFR 98.236(g)(5)(i) are similar to the data element in 40 CFR 98.236(h)(2)(iii) for reporting the total number of hours of venting during completions without hydraulic fracturing. We assigned the data element in 40 CFR 98.236(h)(2)(iii) to the ''Unit/Process Operating Characteristics That are Not Inputs to Emission Equations'' data category and proposed a confidentiality determination of ''not CBI'' because the cumulative venting time for multiple completions or workovers would not disclose information on individual wells and is not likely to cause substantial competitive harm. For the same reasons, we conclude that it is appropriate to assign the data elements in 40 CFR 98.236(g)(5)(i), in the cases where they are not inputs to equations (*i.e.,* when data for more than one well are used in Equation W–10A), to the ''Unit/Process Operating Characteristics That are Not Inputs to Emission Equations'' data category and finalize our determination that these data elements are ''not CBI'' in this action. In the situations where these data elements are used as an input to an equation, we are assigning them to the ''Inputs to Emission Equations'' data category and not making a confidentiality determination for these data.

In the final rule, the EPA has also edited for clarity numerous reporting elements based on public comments. Portions of 40 CFR 98.236 also were rearranged to improve clarity in the final rule. These edits did not change the type of data to be reported and, thus, the confidentiality determinations do not need to be reassessed. All of the changes are documented in the Memorandum ''Final Revisions to the Subpart W Reporting Requirements in the 'Greenhouse Gas Reporting Rule:

2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket Id. No. EPA–HQ–OAR–2011–0512.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed categorical assignments and confidentiality determinations. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses. See the memorandum ''Final Data Category Assignments and Confidentiality Determinations for Data Elements (excluding inputs to emission equations) in the 'Greenhouse Gas Reporting Rule: 2014 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of final data category assignments and confidentiality determinations, and a discussion of changes since proposal.

Comment: Two commenters disagreed with the EPA's statement that the natural gas transmission industry is ''inherently uncompetitive'' or ''less competitive than other industries.'' One commenter pointed out that although interstate natural gas pipeline rates are established on a cost-of-service basis by FERC, the FERC-issued Order 636 has fostered a competitive culture by unbundling pipeline merchant and transportation services. The commenter argued that pipelines face multiple forms of competition which affect service offerings and prices, including: Competition with alternative fuels, competition between gas supply basins, and competition among pipelines. The commenter argued that pipelines sometimes charge customers less than the FERC-approved maximum tariff rate due to competitive market conditions. Another commenter stated that they operate in markets in which other natural gas pipeline companies regularly compete for pipeline business through discounting and other competitive market practices. Both commenters stated that the release of specific operational data could result in substantial harm to a pipeline operator's competitive position.

Response: The EPA agrees with commenters that Order 636 did increase competition. We note, however, that many of the data elements are already publicly available from other sources. The number of compressors (reported under 40 CFR 98.236(aa)(4)(ii)) and the total compressor power rating (reported under 40 CFR 98.236(aa)(4)(iii)) are also available to the public through state and federal construction and operating permits and FERC. The quantity of gas injected into underground storage (reported under 40 CFR 98.236(aa)(5)(i)), the quantity of gas withdrawn from underground storage (reported under 40 CFR 98.236(aa)(5)(ii)), the quantity of LNG injected into storage (reported under 40 CFR 98.236(aa)(8)(ii)), the quantity of LNG withdrawn from storage (reported under 40 CFR 98.236(aa)(8)(ii), the total underground storage capacity (reported under 40 CFR 98.236(aa)(5)(iii)) and the total LNG storage capacity (reported under 40 CFR 98.236(aa)(8)(iii)) are reported annually to the EIA on forms EIA–176 (Annual Report of Natural and Supplemental Gas Supply) and EIA–191 (Monthly Underground Gas Storage Report). The EIA publishes this data on their Web site.[2] Since these data elements are already in the public domain, they are not entitled to confidential treatment under 40 CFR 2.208. We are therefore finalizing as proposed the determination that these data elements are ''not CBI.''

We have not identified any reliable public sources for the following data elements: The quantity of gas transported through a compressor station (reported under 40 CFR 98.236(aa)(4)(i)) and the average upstream and downstream pressures (reported under 40 CFR 98.236(aa)(4)(iv) and (v), respectively). These data elements provide information on the quantity of gas transported by a specific pipeline and disclosure of this data may potentially cause competitive harm to some pipeline companies operating in more competitive market areas. Since the determination would depend on the particular market conditions for each company, the EPA was not able to make a determination for these data elements that would apply for all reporters. Thus, the EPA has decided not to make a confidentiality determination for 40 CFR 98.236(aa)(4)(i), (iv) and (v). The confidentiality status of these data elements will be evaluated on a case-by-case basis, in accordance with the existing CBI regulations in 40 CFR part 2, subpart B, upon receipt of a public request for these data elements.

Comment: One commenter supported classifying as CBI, information in 40 CFR 98.236(d)(1)(iv) on whether any CO_2 emissions from the AGR unit are recovered and transferred outside the facility. The commenter stated that the data element is directly linked to multiple data elements associated with industrial CO_2 production plants and import/exporter of CO_2 that have been previously determined to be CBI under subpart PP (Suppliers of Carbon Dioxide).

Response: The EPA has reviewed the data element referenced by the commenter. The EPA notes that 40 CFR 98.236(d)(1)(iv) includes two data elements. First, reporters must indicate whether CO_2 emissions are recovered from the AGR units and transferred offsite (as proposed). Second, reporters must supply the quantity of CO_2 emissions that are collected and transferred offsite. The second data element in the proposed rule inadvertently removed text stating that reporters should report this information under subpart PP. It would be redundant to report the quantity of CO_2 emissions that are collected and transferred offsite under both subpart PP and subpart W. In this final rule, we are providing that if any CO_2 emissions from the AGR unit were recovered and transferred outside the facility, then the facility must report the annual quantity of CO_2 that was recovered and transferred outside the facility under subpart PP.

Thus, the proposed rule only included one new data element (''Whether any CO_2 emissions are recovered and transferred outside the facility'') for which a confidentiality determination was proposed. The EPA has determined that the data element is not the same data element as reported under subpart PP. Therefore, we are finalizing as proposed our determination that the data element is ''not CBI.'' The EPA disagrees with the commenters' assertion that the proposed determination for ''whether CO_2 emissions are recovered from the AGR units and transferred offsite'' is inconsistent with the determination made for data elements reported under subpart PP. None of the data elements reported under subpart PP are similar to this data element. The determinations for subpart PP were made with regard to quantities of CO_2 from production wells and to the quantities of CO_2 collected and transferred offsite from industrial production facilities. Furthermore, this data element reveals only that the facility has an AGR unit (currently publicly available in permits) and that CO_2 is collected as a byproduct and transferred offsite. Since the CO_2 is only a by-product of the process, the EPA has determined that disclosure of this information would not cause substantial competitive harm.

Comment: Five commenters requested that the EPA review confidentiality

[2] See the EIA Natural Gas Annual Respondent Query System at *http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7.*

determinations for consistency with data elements that are found in both subpart NN and subpart W. Several of these commenters provided citations in subpart NN for data elements that have been given a determination of CBI which also appear in 40 CFR 98.236(aa)(3)(i) through 40 CFR 98.236(aa)(3)(vii) in the proposed rule with a ''non-CBI'' determination.

Response: The EPA has reviewed the confidentiality determinations for subparts W and NN and has determined that two data elements in subpart NN have confidentiality determinations that are inconsistent with those proposed for subpart W. The first is the quantity of natural gas withdrawn from storage in a calendar year (reported under 40 CFR 98.236(aa)(5)(i)), which was proposed to be ''not CBI'' for all underground storage operators. Under subpart NN, local distribution companies report the volume of natural gas withdrawn from on-system storage and the annual volume of LNG withdrawn from storage and vaporized for delivery on the distribution system (40 CFR 98.406(b)(3)), for which we previously made a determination of CBI. However, review of publicly available data undertaken during the preparation of the proposal for this action found that gas withdrawals from underground storage are reported to the EIA on form EIA–176 (Annual Report of Natural And Supplemental Gas Supply and Disposition). As we noted in the proposal, the EIA considers all information submitted on EIA–176 to be non-proprietary information and publishes the quantity of natural gas withdrawn from storage on their Web site. Since the quantity of natural gas withdrawn from storage is publicly available, this data element is not entitled to confidential treatment under the provisions in 40 CFR 2.208. The EPA notes that this final rule relates to calculation and reporting requirements for subpart W and not subpart NN, and therefore inconsistencies with respect to subpart NN are not addressed by this rule.

The second data element is the quantity of gas received at a gas processing plant (reported by natural gas processing plants under 40 CFR 98.236(aa)(3)(i)), which we proposed as ''not CBI.'' Plants that fractionate natural gas into its constituent NGL are required to report the volume of natural gas received by their plant for processing (see 40 CFR 40 CFR 98.406(a)(3)). In a previous notice, we determined that the data element required by 40 CFR 98.406(a)(3) was entitled to confidential treatment under 40 CFR 2.208 because it provided information regarding raw material consumption that we believed was not already in the public domain and could potentially cause competitive harm if disclosed. During the preparation of the proposal for this action, the EPA found that detailed plant-level information is reported by all natural gas plants to the EIA on Schedule A of form EIA–757 (Natural Gas Processing Plant Survey) once every 3 years. The information reported includes the annual average natural gas flow in million cubic feet per day entering a natural gas plant (including plants that also fractionate natural gas). EIA considers the information on annual average natural gas flows entering a plant to be non-proprietary information that it makes available to the public. However, because the information reported to EIA is on a different frequency than that required under subpart W, we have determined that the quantity of natural gas received at a gas processing plant under 40 CFR 98.236(aa)(3)(i) is entitled to confidential treatment under the provisions of 40 CFR 2.208. These data provide detailed information regarding the quantities of natural gas processed that would be likely to cause competitive harm if disclosed as it provides sensitive information on market share. Thus, in this final action we are changing the determination for 40 CFR 98.236(aa)(3)(i) from ''not CBI'' to ''CBI.''

The other data elements specifically mentioned by commenters are either not the same as those reported under subpart NN or they have determinations that are consistent with those in subpart NN. For example, commenters noted that the quantity of NGL (bulk and fractionated) received (reported under 40 CFR 98.236(aa)(3)(iii) and the quantity of NGL (bulk and fractionated) leaving the plant (reported under 40 CFR 98.236(aa)(3)(iv)) are the same as the data elements reported under 40 CFR 98.406(a)(2) and (a)(1), respectively. However, the commenters are mistaken. Under subpart W, the data elements reported are actually aggregated totals for all NGL products received and all NGL products supplied. Under subpart NN, facilities report the quantities of each individual product. The subpart NN data elements were previously determined to be entitled to confidential treatment because they provide detailed information regarding the quantities of individual products that would be likely to cause competitive harm if disclosed as it provides sensitive information on market share. Since the NGL data reported under subpart W is in an aggregated form, the quantities of individual products is not disclosed and therefore does not pose the same risk of causing competitive harm to the reporters. The only exception is in situations where the plant is known to receive or supply only one NGL product. In these situations, the EPA has decided not to make a confidentiality determination for 40 CFR 98.236(aa)(3)(iii) and (aa)(3)(iv).

Comment: One commenter expressed concern about reporting information on exploratory wells in subpart W, especially when the wells are located in step-out areas where no prior reporting exists for a given sub-basin (including vertical or horizontal wells). The commenter explained that the problem occurs when an exploratory well is the sole well in a sub-basin (including vertical or horizontal wells) and is not reported in combination with other wells, thereby shielding any individual well's contribution. The commenter noted that its concerns are related to the timing of releasing the information to the public, as the commenter stated that the information is most sensitive if it is made available too early during the exploration or initial development stages. The commenter stated that the success of a well in exploratory areas could be inferred if detailed data are provided to the public too soon during the exploration and assessment period. The commenter provided an example of such an occurrence: An exploratory well completed in December of the reporting year, data reported to the EPA by end of March of the following year and then released by the EPA to the public within a few months during the same year. The commenter stated that early release of data regarding operating characteristics of such wells, including post-flowback flaring/venting volumes, could cause competitive harm if made publicly available too early.

The commenter noted that Federal law and State codes allow companies to designate as confidential the data obtained from exploratory wells, especially in new discovery areas or areas that are being explored for development. The commenter further noted that the original intent of State oil and gas commissions to allow withholding of select drilling and production information from early release to the public was to allow competitive exploration by searching for new pockets of oil or gas and experimenting with new tools and techniques. The commenter stated that releasing data on such wells through Part 98—despite the fact that they are held confidential by other regulatory bodies—could cause substantial

competitive harm and lead to a loss of investment value. The commenter explained that competitive harm could occur if the public could obtain detailed high-resolution operational information on a well-by-well basis and on a daily or weekly basis.

The commenter requested that the EPA categorically determine that all information associated with exploratory wells, with the exception of well ID and location, be classified as CBI for a period of at least 24 months from the start of exploration. The commenter recommended either of two suggested approaches under Part 98: (1) Companies would report all data to the EPA as mandated by subpart W, but the EPA would hold the reported data as CBI and not include it in its public data release for at least 24 months (this could be accomplished by a flagging system (or a ''radio button'') in the Electronic Greenhouse Gas Reporting Tool that could also allow for a short informative text on why that particular well information is to be maintained confidential); or (2) the EPA could set up a deferral system where initial data on exploratory wells will be well ID and location information and the remaining data would be backfilled by companies after a period of 24 months. The commenter added that neither option would require case-by-case review of companies' information, and both are consistent with the approach taken by state oil and gas commissions and are protective of companies' commercial investment interests. The commenter identified the following data elements as potentially sensitive when reported for exploratory wells:

- Sub-basin ID. (40 CFR 98.236(g)(1))
- Well type. (40 CFR 98.236(g)(2))
- Cumulative backflow time, in hours, for each sub basin. (40 CFR 98.236(g)(5)(i))
- Vented natural gas volume, in standard cubic feet, for each well in the sub-basin. (40 CFR 98.236(g)(6))
- Annual gas emissions, in standard cubic feet. (40 CFR 98.236(g)(7))
- For each sub-basin with gas well completions without hydraulic fracturing and without flaring, Sub-basin ID. (40 CFR 98.236(h)(1)(i))
- For each sub-basin with 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, in standard cubic feet per hour. (40 CFR 98.236(h)(1)(iv))
- For each sub-basin with gas well completions without hydraulic fracturing and with flaring, Sub-basin ID. (40 CFR 98.236(h)(2)(i))
- For each sub-basin with gas well completions without hydraulic fracturing and with flaring, average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour. (40 CFR 98.236(h)(2)(iv))
- At the basin level for atmospheric tanks where emissions were calculated using Calculation Method 3, the total annual oil throughput that is sent to atmospheric tanks in the basin, in barrels. (40 CFR 98.236(j)(2)(i)(A))
- If oil well testing is performed where emissions are not vented to a flare, the average flow rate in barrels of oil per day for well(s) tested. (40 CFR 98.236(l)(1)(iv))
- If oil well testing is performed where emissions are vented to a flare, the average flow rate in barrels of oil per day for well(s) tested. (40 CFR 98.236(l)(2)(iv))
- If gas well testing is performed where emissions are not vented to a flare, the average annual production rate in actual cubic feet per day for well(s) tested. (40 CFR 98.236(l)(3)(iii))
- If gas well testing is performed where emissions are vented to a flare, the average annual production rate in actual cubic feet per day for well(s) tested. (40 CFR 98.236(l)(4)(iii))
- If associated gas was vented or flared during the calendar year, Sub-basin ID. (40 CFR 98.236(m)(1))
- For each sub-basin, indicate whether any associated gas was vented without flaring. (40 CFR 98.236(m)(2))
- For each sub-basin, indicate whether any associated gas was flared. (40 CFR 98.236(m)(3))
- Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared. (40 CFR 98.236(m)(5))
- 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. (40 CFR 98.236(m)(6))
- Formation type. (40 CFR 98.236(aa)(1)(ii)(C))
- For each sub-basin category, the number of producing wells at the end of the calendar year. (40 CFR 98.236(aa)(1)(ii)(D))
- For each sub-basin category, the number of wells completed during the calendar year. (40 CFR 98.236(aa)(1)(ii)(G))
- For offshore production, the quantity of gas produced from the offshore platform in the calendar year for sales. (40 CFR 98.236(aa)(2)(i))

Response: The EPA reviewed the data elements identified by the commenter as having disclosure concerns for exploratory wells (delineation wells and wildcat wells). After further investigation in response to the comment received, review of state laws protecting these types of data, and consistent with the EPA's previous decisions related to exploratory wells under Part 98 (79 FR 63750, October 24, 2014), the EPA has determined that, in the following situations which were not specifically considered in the proposed rule, early public disclosure of some of the data elements associated with wildcat wells and/or delineation wells could reveal the well productivity, thereby resulting in the loss of investment value:

- For gas well completions or workovers with hydraulic fracturing, where wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the measurement;
- For gas well completions without hydraulic fracturing, where wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the measurement;
- For onshore production storage tanks, where wildcat wells and/or delineation wells are the only wells in a sub-basin or basin;
- For well testing, where wildcat wells and/or delineation wells are the only wells in a sub-basin that are tested;
- For associated gas venting and flaring, where wildcat wells and/or delineation wells are the only wells in a sub-basin;

The data elements that could reveal well productivity for wildcat and/or delineation wells in the applicable situations listed above are as follows:

- Cumulative flowback time, in hours, for each sub basin. (40 CFR 98.236(g)(5)(i))
- For the measured well(s), the flowback rate, in standard cubic feet per hour, for each sub-basin. (40 CFR 98.236(g)(5)(ii))
- For each sub-basin with 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, in standard cubic feet per hour. (40 CFR 98.236(h)(1)(iv))
- For each sub-basin with gas well completions without hydraulic fracturing and with flaring, average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour. (40 CFR 98.236(h)(2)(iv))
- At the sub-basin level for atmospheric tanks where emissions were calculated using Calculation Method 1 or 2, the total annual gas-

liquid separator oil volume that is sent to atmospheric storage tanks, in barrels. (40 CFR 98.236(j)(1)(iii))

• At the basin level for atmospheric tanks where emissions were calculated using Calculation Method 3, the total annual oil throughput that is sent to atmospheric tanks in the basin, in barrels. (40 CFR 98.236(j)(2)(i)(A))

• If oil well testing is performed where emissions are not vented to a flare, the average flow rate in barrels of oil per day for well(s) tested. (40 CFR 98.236(l)(1)(iv))

• If oil well testing is performed where emissions are vented to a flare, the average flow rate in barrels of oil per day for well(s) tested. (40 CFR 98.236(l)(2)(iv))

• If gas well testing is performed where emissions are not vented to a flare, the average annual production rate in actual cubic feet per day for well(s) tested. (40 CFR 98.236(l)(3)(iii))

• If gas well testing is performed where emissions are vented to a flare, the average annual production rate in actual cubic feet per day for well(s) tested. (40 CFR 98.236(l)(4)(iii))

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

• 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. (40 CFR 98.236(m)(6))

These 12 data elements are themselves a very small subset of data elements collected in subpart W. Further, wildcat and delineation wells represent a relatively small percentage of the wells being reported under Part 98 for these data elements. As a result, in the interim period before these data are reported to the EPA, the EPA will be able to verify the majority of the emissions using data elements that will be reported to the EPA. For the 12 data elements that may be delayed for 2 years, the EPA will verify emissions using other data reported to the EPA, and will conclude verification upon receipt of the data. The EPA agrees with the commenter that a two year delay of reporting is sufficient to prevent early public disclosure of these data and will provide sufficient time for the reporter to thoroughly conduct an assessment of the well. Given the results of this evaluation, the EPA determined that, for these 12 data elements, in those cases where a reporter has delineation wells or wildcat wells in cases where wildcat wells and/or delineation wells in a sub-basin and these wells meet one of the five situations described above, reporters should be provided an option to delay reporting of the given data element for two reporting years starting in 2015. In such cases, if the two-year delay in reporting is used, the reporter must report the following information in the current reporting year: indicate for each delayed reporting element that one of the five situations listed above is true (*e.g.,* for gas well completions or workovers with hydraulic fracturing, wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the measurement). In addition, when reporters report the delayed data elements to emission equations after the 2 year delay, they must also report the American Petroleum Institute (API) well ID numbers for the applicable wildcat and/or delineation wells in the sub-basin for which the reporting element was delayed. For example, if a delineation or wildcat well is completed in 2015 in a sub-basin that has only delineation or wildcat wells or these are the only wells for which measurements can be made, then the reporter may (1) elect to report these 12 data elements in their 2015 annual report submitted by March 31, 2016; or (2) elect to delay reporting of these data elements for up to two years. If the reporter elects to delay reporting, then the API well ID numbers for the wildcat and delineation wells in the sub-basin for which reporting has been delayed must be reported by March 31, 2016 and the data elements delayed from reporting must be reported no later than March 31, 2018.

The following data elements meet the definition of emission data in 40 CFR 2.301(a)(2)(i) because they are actual volumes of gas emitted by the facility: volume of natural gas vented (reported under 40 CFR 98.236(g)(6)) and annual gas emissions (reported under 40 CFR 98.236(g)(7)). Under CAA section 114(c), the EPA must make available emission data, whether or not such data are CBI. For these data elements that are assigned to the ''Emissions'' data category, the commenter did not claim or provide any justification for why these data elements do not meet the definition of emission data.

For the remaining data elements identified by the commenter as potentially sensitive with respect to delineation and wildcat wells, the EPA disagrees that public disclosure of these data elements in the time period following annual reporting would reveal well productivity, thereby resulting in the loss of investment value to the reporter. The sub-basin ID (reported under 40 CFR 98.236(g)(1), (h)(1)(i), (h)(2)(i), and (m)(1)) and number of wells can be discerned from the well IDs, which are publicly available for all wells and provide the location of the well and the name of the drilling company. Since the location of the well can be discerned from the well ID, the type of formation (reported under 40 CFR 98.236(aa)(1)(ii)(C)) can be determined through publicly available information such as U.S. Geological Survey reports. The well type (reported under 40 CFR 98.236(g)(2)), including whether hydraulic fracturing is used, can be inferred from the formation type. Similarly, although indicating whether the well vents or flares associated gas emissions (reported under 40 CFR 98.236(m)(2) and (m)(3)) identifies the well as an oil well, this information can also be concluded from the formation type, which, as previously mentioned, may be determined through publicly available information. The number of producing wells at the end of the calendar year (reported under 40 CFR 98.236(aa)(1)(ii)(D)) and the number of wells completed during the calendar year (reported under 40 CFR 98.236(aa)(1)(ii)(G)) are reported for sub-basins with production wells. Information regarding production wells is available from state databases. Since these data elements are either not sensitive or can be easily inferred from information already in the public domain, the EPA has determined that release of this information would not result in competitive harm.

IV. Impacts of the Final Amendments to Subpart W

A. Impacts of the Final Amendments

The final amendments to subpart W include technical corrections and revisions to the calculation, monitoring, and reporting requirements that do not significantly increase the burden of data collection and improve the accuracy of the data reported. In general, these revisions provide greater flexibility for reporters and increase the clarity and congruency of the calculation and reporting requirements. These final amendments do not impart significant additional burden to reporters and in some cases reduce burden to reporters and regulators.

First, the following revisions to the calculation and monitoring requirements of subpart W are anticipated to decrease the burden or have no impact on the burden relative to the burden to comply with the current rule:

• Allowing for the use of either site-specific composition data or a default gas composition for natural gas transmission compression, underground natural gas storage, LNG storage, LNG

import and export, and natural gas distribution facilities.

• For well venting from liquids unloading, allowing the measurement period to differ slightly from the standard calendar year combined with annualizing the resulting venting data for facilities that calculate emissions using a recording flow meter.

• Allowing for the option to use a site-specific compressibility factor for calculation of emissions from blowdown vents and for conversion of volumetric emissions at actual conditions to standard conditions.

• Revising calculation methods for onshore production storage tanks to require quantification of emissions from well pad gas-liquid separator liquid dump valves only if the dump valve is determined to not be closing properly.

• Including a term to account for situations where part of the associated gas from a well goes to a sales line while another part of the gas is flared or vented. The term is already being calculated elsewhere and/or can be estimated.

• Deciding against finalizing the addition of the term ''$ERE_{p,q}$'' for emissions reported under other sources; therefore, reporters will not be required to track these emissions.

• Removing vented compressor emissions routed to a flare from the compressor emissions total and retaining the requirement to report uncontrolled vented emissions from compressors.

• Addressing reporter concerns related to measuring centrifugal and reciprocating compressor emissions that are routed to a common vent manifold or flare header. Reporters were previously required to conduct emissions measurements for each individual compressor routed to the common vent. The final rule requires only a single annual emissions measurement at the common vent for groups of manifolded compressors. We are not finalizing the proposed requirement to conduct measurement of manifolded compressor source emissions before comingling with emissions from other sources.

• Revising requirements to conduct measurements in the not-operating-depressurized mode once every three years or at the next scheduled depressurized shutdown (for centrifugal compressors) or at the next scheduled shutdown when the compressor rod packing is replaced (for reciprocating compressors). We are not finalizing the proposed requirement to conduct testing in the operating-mode once every 3 years.

• Revising calculation methods for the natural gas distribution segment to clarify the calculation methodologies and reporting requirements for above grade metering-regulating stations.

• Removing the existing best available monitoring method (BAMM) provisions in 40 CFR 98.234(f) and providing transitional BAMM for the 2015 calendar year. Removing the existing provisions does not add to previous burden estimates for subpart W reporters; these estimates were prepared based on all reporters complying with the monitoring methods in 40 CFR 98.234 without BAMM. The transitional BAMM included in this final rule would allow facilities to obtain the necessary equipment to conduct measurements as required under the revised calculation methods in this final rule, and would not add to the burden estimates included in the proposed rule. (See further discussion in Section II.D of this preamble.)

• Providing for the use of optical gas imaging as a screening tool to detect emissions from reciprocating and centrifugal compressors; measurement to quantify the emissions is required only if the screening detects emissions.

• Providing clarified, specific missing data procedures that provide guidance for reporters when a measurement is inadvertently missed.

Second, the following revisions to the calculation, monitoring, and reporting requirements of subpart W slightly increase the burden relative to the burden to comply with the current rule:

• Revising the calculation and reporting requirements for completions and workovers to differentiate between completions and workovers with different well type combinations in each sub-basin category.

• Revising the calculation and reporting requirements for onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export to include emissions from flare stacks.

Finally, the following revisions to the reporting requirements for subpart W do increase the burden of data collection, but not significantly. As further discussed in Section II of this preamble, the EPA is finalizing the addition of 247 new data elements, while substantially revising 13 data elements and deleting 34 data elements that were required to be reported under Part 98. Although not previously required to be reported, many of these data elements are typically already collected by reporters, related to data that are already being reported, or are readily available to reporters. For example, some of the new reporting elements are required for use in subpart W equations used to calculate emissions and others are collected to differentiate between identical equipment types.

These final additions improve the quality of the data reported by removing ambiguity for the reporter and do not increase burden significantly, since the reporting elements are already available.

The EPA received multiple comments regarding the impacts of the proposed amendments. After evaluating these comments and reviewing other changes from proposal, the EPA revised the impacts assessment. The final amendments to subpart W are not expected to significantly increase burden. See the memorandum, ''Assessment of Impacts of the 2014 Final Revisions to Subpart W'' in Docket Id. No. EPA–HQ–OAR–2011–0512 for additional information.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the impacts of the proposed amendments to subpart W of Part 98. See the 2014 response to comment document in Docket Id. No. EPA–HQ–OAR–2011–0512 for a complete listing of all comments and responses.

Comment: Several commenters stated that the EPA significantly over-simplified the impacts and underestimated the burden associated with the proposed rule. Specifically, commenters expressed concern that EPA has significantly underestimated the additional time and cost burden of the expanded reporting requirements. One commenter considered the implementation cost to be underestimated by an order of magnitude or more, providing an estimate of an additional $150,000 per company or more to initially identify, collect, document and report the new data elements with another $100,000 per year. This commenter critiqued the ''Assessment of Impacts of 2014 Proposed Revisions to Subpart W'' and the information collection request (ICR) Supporting Statement and stated that many of the time and cost burdens should be much higher than the numbers included in these documents. The commenter stated that the cost estimates do not include management tasks including review of the proposed rule and final revisions, monitoring plan revisions, internal communications, coordination with technical staff, training, systems updates, or associated budgeting and planning. One concern was the assumption that 3 minutes would be required to find, document, and report each new data element. The

commenter pointed out that the estimate does not consider the level of effort required to determine who collects the data or how and where it is documented. Another commenter reported that their company had invested in a robust system to manage data collection and reporting according to the original rule requirements, and the revised changes would be burdensome and costly.

Response: Although the commenter did not elaborate on the assumptions used to calculate the $150,000 initial cost or the $100,000 annual cost, the EPA disagrees with the magnitude of these costs. Overall, the EPA has determined that the cost estimates provided by the commenters do not take into consideration the completion of one-time activities that occurred in the first year of data collection. In the EPA's cost estimates, we assumed the startup costs would be incurred during the first year of reporting, *i.e.,* the 2011 reporting year. These costs included the labor burden of planning, registration, and installing required equipment to comply with the rule, as well as the initial costs of developing a data tracking system.

The EPA maintains that allowing 3 minutes per data element is accurate. All new reporting elements are related to emission sources for which information is already being gathered and reported under subpart W. The new elements include such information as the name or ID of the emission source, measurement dates, installation dates, maintenance dates, equipment counts, measurement counts, operating hours, etc. Most, if not all, of these elements can be gathered at the same time as required measurements are being taken.

Comment: One commenter stated that the EPA cost analysis incorrectly assumes an incremental time of 10 minutes for a technician to conduct each additional compressor source measurement for manifolded compressors. The commenter stated that this estimate fails to consider the time required to move personnel and equipment from compressor to compressor and the cautious pace of work and work practices (*e.g.,* use of lanyard and/or other fall protection) for safely working at elevated locations. The commenter also pointed out that the measurement estimate appears to assume that the technician is working alone, reiterating that personnel do not work alone at elevated locations. The commenter further asserted that the EPA's burden estimate for compressor testing appears to include costs only for the testing contractor and does not include facility and company costs including scheduling, coordination, and test team support. The commenter stated that the proposed rule fails to account for costs associated with three separate measurements.

Response: The original burden estimate referenced by the commenter was an adjustment to the burden estimate for the subpart W 2010 final rule to reflect the proposed changes for manifolded compressors. For manifolded compressors, the EPA proposed that reporters may measure downstream of the manifold, in lieu of measuring each compressor source individually. Therefore, the measurement burden estimates assumed that the technician would be taking a single measurement at the manifold and that the level of effort associated with manifolded measurements are similar to the level of effort associated with measurements for individual compressors.

Additionally, in this final rule, we are specifying that ''as found'' measurements from manifolded compressors be taken one time per year instead of three separate measurements per year as proposed.

V. 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 not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

In addition, the EPA prepared an analysis of the potential costs and benefits associated with the final amendments to subpart W. This analysis is contained in the memorandum ''Assessment of Impacts of the 2014 Final Revisions to Subpart W.'' A copy of the analysis is available in the docket for this action (see Docket Id. No. EPA–HQ–OAR–2011–0512) and the analysis is briefly summarized in Section IV of this preamble.

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The ICR document prepared by the EPA has been assigned OMB control number 2060–0629 and EPA ICR tracking number 2300.15.

This action simplifies the existing reporting methods in subpart W, clarifies monitoring methods and data reporting requirements, and finalizes confidentiality determinations for reported data elements. The EPA is restructuring the reporting requirements for clarity and to align them with the calculation requirements by adding 247 new data elements, substantially revising 13 data elements, and deleting 34 data elements.

OMB has previously approved the information collection requirements for 40 CFR part 98 under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.,* and has assigned OMB control number 2060–0629 and EPA ICR tracking number 2300.12. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. Burden is defined at 5 CFR 1320.3(b).

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.

The information collection will result in an overall increase in annual burden of approximately 7,700 hours and $600,000. The estimated total projected cost and hour burden associated with reporting for subpart W are approximately $22,024,000 and 244,000 hours, respectively. For the hour burden, the estimated average burden hours per response is 53.7 hours, the frequency of response is once annually, and the estimated number of likely respondents is 2,885. These amendments to subpart W affect the labor costs, not the capital costs and operation and maintenance (O&M) costs. Therefore, the estimated total capital and start-up cost of monitoring equipment and related facility/process modifications annualized over the expected useful life of the equipment remains at $796,000 per year, and the total O&M cost remains at $1,690,000 per year. The total labor cost is $19,538,000 per year for all of subpart W.

C. Regulatory Flexibility Act (RFA)

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

This action (1) amends monitoring and calculation methodologies in subpart W; (2) amends reporting requirements; (3) assigns subpart W data reporting elements into CBI data categories; and (4) amends a definition in subpart A. After considering the economic impacts of these final rule amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by this final rule include small businesses in the petroleum and gas industry, small governmental jurisdictions and small non-profits. The EPA has determined that some small businesses would be affected because their production processes emit GHGs exceeding the reporting threshold.

This action includes final amendments that do not result in a significant burden increase on subpart W reporters. In some cases, the EPA is increasing flexibility in the selection of methods used for calculating GHGs, and is also revising certain methods that may result in greater conformance to current industry practices. In addition, the EPA is revising specific provisions to provide clarity on what information is being reported. These revisions would not significantly increase the burden on reporters while maintaining the data quality of the information being reported to the EPA.

Although this final rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless has tried to reduce the impact of this rule on small entities. As part of the process of finalizing the subpart W 2010 final rule, the EPA took several steps to evaluate the effect of the rule on small entities. For example, the EPA determined appropriate thresholds that reduced the number of small businesses reporting. In addition, the EPA supports a ''help desk'' for the rule, which is available to answer questions on the provisions in the rule. Finally, the EPA continues to conduct significant outreach on the GHG reporting rule and maintains an ''open door'' policy for stakeholders to help inform the EPA's understanding of key issues for the industries.

D. Unfunded Mandates Reform Act (UMRA)

This rule contains no federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Thus, this rule is not subject to the requirements of section 202 and 205 of the UMRA. This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This action (1) amends monitoring and calculation methodologies in subpart W; (2) amends reporting requirements, (3) assigns subpart W data reporting elements into CBI data categories; and (4) amends a definition in subpart A. The rule applies to few, if any, small governments. Therefore, this action is not subject to the requirements of section 203 of the UMRA.

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, as specified in Executive Order 13132. However, for a more detailed discussion about how Part 98 relates to existing state programs, please see Section II of the preamble to the final Part 98 rule (74 FR 56266, October 30, 2009).

Few, if any, state or local government facilities would be affected by the provisions in this rule. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, Executive Order 13132 does not apply to this action.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this action may have tribal implications. However, it will neither impose substantial new direct compliance costs on tribal governments, nor preempt Tribal law. This regulation would apply directly to petroleum and natural gas facilities that emit GHGs. Although few facilities that would be subject to the rule are likely to be owned by tribal governments, the EPA has sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final subpart W that was promulgated on November 30, 2010 (75 FR 74458). The EPA consulted with tribal officials early in the process of developing subpart W to permit them to have meaningful and timely input into its development.

For additional information about the EPA's interactions with tribal governments, see Section IV.F of the preamble to the re-proposal of subpart W published on April 12, 2010 (75 FR 18608), and Section IV.F of the preamble to the subpart W 2010 final rule published on November 30, 2010 (75 FR 74458).

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

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

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

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical

standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards. This action does not involve the use of any new technical standards. No changes are being finalized that affect the test methods currently in use for subpart W. Although the EPA is revising this final rule to allow for the use of additional measurement methods (optical gas imaging instrument) for pre-screening of compressor valve leakage, these revisions rely on existing technical standards in subpart W for similar emission sources. Therefore, the EPA is not considering the use of any new voluntary consensus standards.

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

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

The EPA has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. Instead, this rule addresses information collection and reporting procedures.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective on January 1, 2015.

List of Subjects in 40 CFR Part 98

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

Dated: November 13, 2014.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended 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 PROVISIONS

■ 2. Section 98.6 is amended by revising the definition of ''Well completions'' to read as follows:

§ 98.6 Definitions.

* * * * *

Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

* * * * *

Subpart W—PETROLEUM AND NATURAL GAS SYSTEMS

■ 3. Section 98.230 is amended by revising paragraph (a)(2) 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 CO_2 or natural gas injection.

* * * * *

■ 4. Section 98.232 is amended by:

■ a. Revising paragraphs (c)(11), (d)(1), and (e)(1);

■ b. Adding paragraph (e)(6);

■ c. Revising paragraph (f)(1) and adding paragraph (f)(4);

■ d. Revising paragraph (g)(1) and adding paragraph (g)(4);

■ e. Revising paragraph (h)(1) and adding paragraph (h)(5); and

■ f. Revising paragraphs (i)(1) through (i)(7).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

* * * * *

(c) * * *

(11) Reciprocating compressor venting.

* * * * *

(d) * * *

(1) Reciprocating compressor venting.

* * * * *

(e) * * *

(1) Reciprocating compressor venting.

* * * * *

(6) Flare stack emissions.

(f) * * *

(1) Reciprocating compressor venting.

* * * * *

(4) Flare stack emissions.

* * * * *

(g) * * *

(1) Reciprocating compressor venting.

* * * * *

(4) Flare stack emissions.

(h) ** * *

(1) Reciprocating compressor venting.

* * * * *

(5) Flare stack emissions.

(i) * * *

(1) Equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines at above grade transmission-distribution transfer stations.

(2) Equipment leaks at below grade transmission-distribution transfer stations.

(3) Equipment leaks at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(4) Equipment leaks at below grade metering-regulating stations.

(5) Distribution main equipment leaks.

(6) Distribution services equipment leaks.

(7) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in § 98.233(z).

* * * * *

■ 5. Section 98.233 is amended by:

■ a. Revising the introductory text;

■ b. Revising paragraphs (a) introductory text, (a)(1), and (a)(2) and adding paragraph (a)(4);

■ c. Revising paragraphs (c), (d), (e), (f), (g), (h), and (i);

■ d. Revising paragraphs (j) introductory text, (j)(1) introductory text, (j)(1)(vii) introductory text, and (j)(2);

■ e. Removing paragraphs (j)(3) and (j)(4);

■ f. Redesignating paragraphs (j)(5) through (j)(9) as paragraphs (j)(3) through (j)(7) and revising newly redesignated paragraphs (j)(3) through (j)(7);

■ g. Revising paragraphs (k), (l), (m), (n), (o), (p), (q), and (r);

■ h. Revising paragraphs (s)(2) introductory text, (s)(2)(i), (s)(3), and (s)(4);

■ i. Revising paragraphs (t) introductory text, (t)(1), and (t)(2);

■ j. Revising paragraphs (u) introductory text and (u)(2)(iii) through (vii);

■ k. Revising paragraphs (v), (w) introductory text, (w)(1), and (w)(3) introductory text;

■ l. Revising the parameters ''$Mass_{CO2}$,'' ''N,'' and ''V_v'' to Equation W–37 in paragraph (w)(3);

■ m. Revising the introductory text of paragraph (x) and paragraph (x)(1);

■ n. Revising the parameter ''S_{hl}'' to Equation W–38 in paragraph (x)(2);

■ o. Revising paragraph (z)(1);

■ p. Revising the parameters ''V_a,'' ''Y_{CO2},'' ''Y_j,'' and ''Y_{CH4}'' to Equations W–39A and W–39B in paragraph (z)(2)(iii);

■ q. Revising Equation W–40 in paragraph (z)(2)(vi) and the parameters ''$Mass_{N2O}$,'' ''Fuel,'' and ''HHV'' to Equation W–40 in paragraph (z)(2)(vi);

■ r. Removing the parameter ''GWP'' of Equation W–40 in paragraph (z)(2)(vi).

The revisions and additions 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 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1 of this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types ''t'' (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type ''t'' (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1) or (a)(2) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i), (iii), and (iv) of this section.

T_t = Average estimated number of hours in the operating year the devices, of each type ''t'', were operational using engineering estimates based on best available data. Default is 8,760 hours.

(1) For all industry segments, determine ''$Count_t$'' for Equation W–1 of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the devices, except as specified in paragraph (a)(2) of this section. The reported number of devices must represent the total number of devices for the reporting year.

(2) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine ''$Count_t$'' for Equation W–1 of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

* * * * *

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

* * * * *

(c) *Natural gas driven pneumatic pump venting.* (1) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under this paragraph (c).

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-2)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps.

EF = Population emissions factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W–1A of this subpart for onshore petroleum and natural gas production.

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 were operational using engineering estimates based on best available data. Default is 8,760 hours.

(2) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(d) *Acid gas removal (AGR) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or emitted through a flare, engine (*e.g.,* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant, using any of the calculation methods described in this paragraph (d), 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). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGR units.

(2) *Calculation Method 2.* 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 of this section.

$$E_{a,CO_2} = V_s * Vol_{CO_2} \qquad \text{(Eq. W-3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit 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_{CO2} = Annual average volumetric fraction of CO_2 content in vent gas flowing out of the AGR unit as determined in paragraph (d)(6) of this section.

(3) *Calculation Method 3.* If a CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equations W–4A or W–4B of this section. If inlet gas flow rate is known, use Equation W–4A. If outlet gas flow rate is known, use Equation W–4B.

$$E_{a,CO2} = V_{in} * \left[\frac{Vol_I - Vol_O}{1 - Vol_O} \right] \qquad \text{(Eq. W-4A)}$$

$$E_{a,CO2} = V_{out} * \left[\frac{Vol_I - Vol_O}{1 - Vol_I} \right] \qquad \text{(Eq. W-4B)}$$

Where:

$E_{a,\ CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR unit 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 unit in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

Vol_I = Annual average volumetric fraction of CO_2 content in natural gas flowing into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_o = Annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit as determined in paragraph (d)(8) of 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. 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:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) For Calculation Method 3, determine the gas flow rate of the inlet when using Equation W–4A of this section or the gas flow rate of the outlet when using Equation W–4B of this section for the natural gas stream of an AGR unit 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) For Calculation Method 2, 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 unit is operating to determine Vol_{CO2} in Equation W–3 of this section, according to the methods set forth in § 98.234(b).

(7) 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 unit is operating to determine Vol_I in Equation W–4A or W–4B of this section, according to the methods set forth in § 98.234(b).

(8) For Calculation Method 3, determine annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit using one of the methods specified in paragraphs (d)(8)(i) through (d)(8)(iii) of this section.

(i) If a continuous gas analyzer is installed on the outlet 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 gas stream for each quarter that the AGR unit is operating to determine Vol_O in Equation W–4A or W–4B of 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 sales line quality specification for CO_2 in natural gas.

(9) Calculate annual volumetric CO_2 emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Calculate annual mass CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if CO_2 emissions from the AGR unit are recovered and transferred outside the facility. Adjust the CO_2 emissions estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of CO_2 emissions recovered and transferred outside the facility.

(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. 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.

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day by using a software program, such as AspenTech HYSYS® or GRI–GLYCalc™, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. 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:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(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.

(xi) Wet natural gas composition. Determine this parameter using one of the methods described in paragraphs (e)(1)(xi)(A) through (D) of this section.

(A) Use the GHG mole fraction as defined in paragraph (u)(2)(i) or (ii) of this section.

(B) If the GHG mole fraction cannot be determined using paragraph (u)(2)(i) or (ii) of this section, select a representative analysis.

(C) 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 specified in § 98.234(b) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Method 2.* Calculate annual volumetric emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day using Equation W–5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

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 of daily natural gas throughput that is less than 0.4 million standard cubic feet per day.

1000 = Conversion of EF_i 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 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.

$$E_{s,n} = \frac{\left(H * D^2 * \pi * P_2 * \%G * N\right)}{(4 * P_1 * 100)} \qquad \text{(Eq. W-6)}$$

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) For glycol dehydrators that use the calculation method in paragraph (e)(2) of this section, calculate both CH_4 and CO_2 mass emissions from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For desiccant dehydrators that use the calculation method in paragraph (e)(3) of this section, calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1), (2), and (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(6) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(i) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) through (5) of this section, as applicable.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(f) *Well venting for liquids unloadings.* Calculate annual volumetric natural gas emissions from well venting for liquids unloading using one of the calculation methods described in paragraphs (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.

(1) *Calculation Method 1.* Calculate emissions from 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 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 of this section. For any tubing diameter group and pressure group combination in a sub-basin where liquids unloading occurs both with and without plunger lifts, Equation W–7A will be used twice, once for wells with plunger lifts and once for wells without plunger lifts.

$$E_a = FR \sum_{p=1}^{h} T_p \qquad \text{(Eq. W-7A)}$$

Where:

E_a = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions, a, in cubic feet. Calculate emission from wells with plunger lifts and wells without plunger lifts separately.
h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin either with or without plunger lifts.
p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.
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, T_p, using Equation W–7B of this section.
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.

$$T_p = \frac{HR_p}{MP_p} \text{ x } D_p \qquad \text{(Eq. W-7B)}$$

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 of 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 plunger lifts and wells 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 all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(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 sub-basin from well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W–8 of this section.

$$E_s = \sum_{p=1}^{W} \left[V_p \times \left(\left(0.37 \times 10^{-3}\right) \times CD_p^2 \times WD_p \times SP_p \right) + \sum_{q=1}^{V_p} \left(SFR_p \times \left(HR_{p,q} - 1.0 \right) \times Z_{p,q} \right) \right] \qquad \text{(Eq. W-8)}$$

Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_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 each well, p, in inches.

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p = For each 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 each well, you may determine the casing pressure by multiplying the tubing pressure of each 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 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each 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 $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ 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 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-9)}$$

Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period for each 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 each well, p, in inches.

WD_p = Tubing depth to plunger bumper for each well, p, in feet.

SP_p = Flow-line pressure for each 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 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each 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) 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) *Gas well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well venting during completions and workovers involving hydraulic fracturing using Equation W–10A or Equation W–10B of this section. Equation W–10A applies to well venting when the flowback rate is measured from a specified number of example completions or workovers and Equation W–10B applies when the 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 of this section, you must follow the procedures specified in paragraph (g)(1) of this section. 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 gas 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.

$$E_{s,n} = \sum_{p=1}^{W}\left[T_{p,s} \times FRM_s \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \div 2 \times PR_{s,p}\right]\right] \quad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W}\left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \div 2\right]\right] \quad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during 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.

FRM_s = Ratio of average 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, expressed in standard cubic feet per hour.

FRM_i = Ratio of initial flowback rate during 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)(iv) of this section, expressed in standard cubic feet per hour, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average production flow rate during the first 30 days of production after completions of newly drilled gas wells or gas 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.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job 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. 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 vented or flared of each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure 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).

(1) If you elect to use Equation W–10A of this section, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section, or 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, 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 as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W–12B 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 making flowback measurements for use in Equations W–12A and W–12B of this section, you must use a recording flow meter (digital or analog) installed on the vent line, ahead of a flare or vent, to measure the flowback rates in units of standard cubic feet per hour according to methods set forth in § 98.234(b).

(ii) *Calculation Method 2.* You must use Equation W–12A as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W–12B 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 of 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 of this section for subsonic flow or Equation W–11B of this section for sonic flow. You must use best engineering estimates based on best available data along with Equation W–11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W–11C of 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 of this section using Equation W–33 in paragraph (t) of 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.

$$FR_a = 1.27*10^5 * A * \sqrt{187.08*T_u} \quad \text{(Eq. W-11B)}$$

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.

$$R = P1/P2 \quad \text{(Eq. W-11C)}$$

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 of this section, calculate FRM_s using Equation W–12A of this section.

$$FRM_s = \frac{\sum_{p=1}^{N} FR_{s,p}}{\sum_{p=1}^{N} PR_{s,p}} \quad \text{(Eq. W-12A)}$$

Where:

FRM_s = Ratio of average 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 production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average 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 in paragraph (t) of this section. You may not use flow volume as used in Equation W–10B converted to a flow rate for this parameter.

$PR_{s,p}$ = Average production flow rate during the first 30 days of production after completions of newly drilled gas wells or gas 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.

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 of this section, calculate FRM_i using Equation W–12B of this section.

$$FRMi = \frac{\sum_{p=1}^{N} FR_{i,p}}{\sum_{p=1}^{N} PR_{s,p}} \quad \text{(Eq. W-12B)}$$

Where:

FRM_i = Ratio of flowback gas rate while flowing to open tanks/pits during well completions and workovers from hydraulic fracturing to 30-day production rate.

$FR_{i,p}$ = 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.

$PR_{s,p}$ = Average production flow rate during the first 30-days of production after completions of newly drilled gas wells or gas 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.

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 of this section, the ratio of flowback rate during well completions and workovers from hydraulic fracturing to 30-day production rate for horizontal and vertical wells are applied to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well workovers, respectively, in the gas producing sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average production rate for each of these wells.

(vi) For Equation W–12A and W–12B of this section, calculate new flowback rates for horizontal and vertical gas well completions and horizontal and vertical gas well workovers in each sub-basin category once every two years starting in the first calendar year of data collection.

(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 (iii) 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.

(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.

(4) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing where all or a portion of the gas is flared as specified in paragraphs (g)(4)(i) and (ii) of this section.

(i) Use the volumetric total natural gas emissions vented to the atmosphere during well completions and workovers as determined in paragraph (g) of this section to calculate volumetric and mass emissions using paragraphs (u) and (v) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to adjust emissions for the portion of gas flared during well completions and workovers using hydraulic fracturing. This adjustment to emissions from completions using flaring, versus completions without flaring, accounts for the conversion of CH_4 to CO_2 in the flare and for the formation on N_2O during flaring.

(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 of this section. Calculate annual volumetric natural gas emissions from each gas well venting during completions without hydraulic fracturing using Equation W–13B of 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 (h)(2) of this section.

$$E_{s,wo} = N_{wo} * EF_{wo} \quad \text{(Eq. W-13A)}$$

$$E_{s,p} = \sum_{p=1}^{f} V_p * T_p \quad \text{(Eq. W-13B)}$$

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 sub-basin category 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.

p = Well completions 1 through f in a sub-basin.

f = Total number of well completions without hydraulic fracturing in a sub-basin category.

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 wells 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 to either the atmosphere or a flare 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) Calculate annual emissions of CH_4, CO_2, and N_2O from gas well venting to flares during well completions and workovers not involving hydraulic fracturing as specified in paragraphs (h)(2)(i) and (ii) of this section.

(i) Use the gas well venting volume and gas composition during well completions and workovers that are flared as determined using the methods specified in paragraphs (h) and (h)(1) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine emissions from the flare for gas well venting to a flare during completions and workovers without hydraulic fracturing.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from the depressurization of equipment to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance as specified in either paragraph (i)(2) or (3) of this section. You may use the method in paragraph (i)(2) of this section for some blowdown vent stacks at your facility and the method in paragraph (i)(3) of this section for other blowdown vent stacks at your facility. Equipment with a unique physical volume of less than 50 cubic feet as determined in paragraph (i)(1) of this section are not subject to the requirements in paragraphs (i)(2) through (4) of this section. The requirements in this paragraph (i) do not apply to blowdown vent stack emissions from depressurizing to a flare, over-pressure relief, operating pressure control venting, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading.

(1) *Method for calculating unique 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.

(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) or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. Equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary other than physical volumes associated with distribution pipelines), pipeline venting (*i.e.,* physical volumes associated with distribution pipelines vented 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.

(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 of 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 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).
P_s = Absolute pressure at standard conditions (14.7 psia).
P_a = Absolute pressure at actual conditions in the unique physical volume (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.

$$E_{s,n} = \sum_{p=1}^{N} \left[V_p \left(\frac{(459.67 + T_s)(P_{a,b,p} - P_{a,e,p})}{(459.67 + T_{a,p}) P_s Z_a} \right) \right] \quad \text{(Eq. W-14B)}$$

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''.
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''.
$P_{a,e,p}$ = 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.
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 of paragraph (i)(2)(i) of 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 of paragraph (i)(2)(i) of 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.

(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) *Onshore production 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 (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For wells flowing to gas-liquid separators 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 flowing directly to atmospheric storage tanks without passing through a wellhead separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For wells flowing to gas-liquid separators or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. The following parameters must be determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from liquid transferred to tanks:

* * * * *

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described

in paragraphs (j)(1)(vii)(A) through (C) of this section.

* * * * *

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section for wells flowing to gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks.

(i) *Flow to storage tank after passing through a separator.* Assume that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(ii) *Flow to storage tank direct from wells.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(B) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions using Equation W–15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-15)}$$

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 or wells in thousand standard cubic feet per separator or well 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 or wells with annual average daily throughput less than 10 barrels per day. Count only separators or wells that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(4) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(5) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i,o} = \left(CF_n * \frac{E_n}{8760} * T_n \right) \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i,o}$ = Annual volumetric GHG emissions at standard conditions from each storage tank in cubic feet that resulted from the dump valve on the gas-liquid separator not closing properly.

E_n = Storage tank emissions as determined in paragraphs (j)(1), (j)(2) and, if applicable, (j)(4) of this section in standard cubic feet per year.

T_n = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_n based on maintenance, operations, or routine well pad inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_n = Correction factor for tank emissions for time period T_n is 2.87 for crude oil production. Correction factor for tank emissions for time period T_n is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

(7) Calculate both CH_4 and CO_2 mass emissions from natural gas volumetric emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, calculate CH_4 and CO_2 annual emissions from compressor scrubber dump valve leakage as specified in paragraphs (k)(1) through (k)(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 (k)(5) of this section.

(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.

(5) Calculate annual emissions from storage tanks to flares as specified in paragraphs (k)(5)(i) and (ii) of this section.

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions sent to a flare.

(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 (l)(6) of this section.

(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 (for oil wells) or Equation W–17B (for gas wells) of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq. W-17A)}$$

$$E_{a,n} = PR * D \qquad \text{(Eq. W-17B)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; 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(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the calendar year that the well(s) 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.

(6) Calculate emissions from well testing if emissions are routed to a flare as specified in paragraphs (l)(6)(i) and (ii) of this section.

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(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): Well testing venting and flaring of this section) as specified in paragraphs (m)(1) through (4) 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 (m)(5) of this section.

(1) 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.

(2) If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraphs (m)(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–18 of this section.

$$E_{s,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} \left[\left(GOR_{p,q} * V_{p,q} \right) - SG_{p,q} \right] \qquad \text{(Eq. W-18)}$$

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.

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate emissions from associated natural gas if emissions are routed to a flare as specified in paragraphs (m)(5)(i) and (ii) of this section.

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as specified in paragraphs (n)(1) through (9) of this section.

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as specified in paragraphs (n)(2)(i) through (iii) of this section.

(i) For onshore natural gas production, determine the GHG mole fraction using paragraph (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole fraction in feed natural gas for all streams 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 fraction in feed natural gas liquid for all streams.

(iii) For any industry segment required to report to flare stack emissions under § 98.232, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Convert GHG volumetric emissions to standard conditions using calculations in paragraph (t) of this section.

(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W–19 and W–20 of this section.

$$E_{s,CH4} = V_s * X_{CH4} * \left[(1-\eta) * Z_L + Z_U \right] \quad \text{(Eq. W-19)}$$

$$E_{s,CO2} = V_s * X_{CO2} + \sum_{j=1}^{5} \left(\eta * V_s * Y_j * R_j * Z_L \right) \quad \text{(Eq. W-20)}$$

Where:

$E_{s,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, at standard conditions.

$E_{s,CO2}$ = 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)(1) of this section.

η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare (default is 0.98).

X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

Z_U = Fraction of the feed gas sent to an un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

Z_L = Fraction of the feed gas sent to a burning flare (equal to $1 - Z_U$).

Y_j = Mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare as determined in paragraph (n)(1) 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).

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculation in paragraph (v) of this section.

(7) Calculate N_2O emissions from flare stacks using Equation W–40 in paragraph (z) of this section.

(8) 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 only CO_2 emissions for the flare. 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 emissions, the requirements specified in paragraphs (n)(1) through (7) of this section are not required.

(9) The flare emissions determined under this paragraph (n) must be corrected for flare emissions calculated and reported under other paragraphs of

this section to avoid double counting of these emissions.

(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 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 (o)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) of this section do not apply. 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), 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.

(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) or (B) 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 paragraphs (o)(1)(i)(C) and (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 either paragraph (o)(2)(i)(A) or (B) of this section and, if the compressor has wet seal oil degassing vents, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (o)(2)(i)(A), (B), or (C) 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) You must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If three consecutive calendar years occur without measuring the compressor in not-operating-depressurized-mode, you must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at the next scheduled depressurized shutdown. The requirement specified in this paragraph does not apply if the compressor has blind flanges in place throughout the reporting year. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(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, and the volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(i) For blowdown valves on compressors in operating-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, determine vapor volumes at standard conditions, using a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(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 (E) 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) An acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(E) 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)(4)(ii)(A) through (o)(4)(ii)(D) 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.

(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 of this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) and (B) 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 $E_{s,i,m}$ 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) or (o)(1)(i)(B) of this section that was measured for the reporting year.

(ii) Using Equation W–22 of this section, calculate the annual volumetric GHG emissions from each centrifugal compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-22)}$$

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 $E_{s,i,m}$ 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) or (o)(1)(i)(B) of this section that was not measured in the reporting year.

(iii) Using Equation W–23 of this section, develop an emission factor for each compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section. These emission factors must be calculated annually and used in Equation W–22 of this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \qquad \text{(Eq. W-23)}$$

Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W–22 of 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 of 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) or (o)(1)(i)(B) of this section.

(iv) The reporter emission factor in Equation W–23 of 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 of this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \qquad \text{(Eq. W-24A)}$$

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 of 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.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \qquad \text{(Eq. W-24B)}$$

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), (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 of 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.* You must calculate emissions from centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility using Equation W–25 of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from centrifugal compressor wet seals, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors that have wet seal oil degassing vents.

$EF_{i,s}$ = Emission factor for GHG_i. 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.

(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.

(12) *General requirements for calculating volumetric GHG emissions from centrifugal compressors routed to flares.* You must calculate and report emissions from all centrifugal compressor sources that are routed to a flare as specified in paragraphs (o)(12)(i) through (iii) of this section.

(i) Paragraphs (o)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in § 98.236(o).

(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 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 (p)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (p)(1) through (12) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) of this section do not apply. 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), 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.

(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 paragraphs (p)(1)(i)(D) and (E) 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 either paragraph (p)(2)(i)(A) or (B) of this section, and measure volumetric emissions from

reciprocating rod packing as specified in paragraph (p)(2)(ii) of this section.

(B) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (p)(2)(i)(A) or (B) of this section.

(C) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (p)(2)(i)(A), (B), or (C) 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.

(D) You must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If there is no scheduled shutdown within three consecutive calendar years, you must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at the next scheduled depressurized shutdown. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(E) 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.

(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, 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) 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 (p)(2)(ii)(A) and (p)(4)(ii)(B) 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.

(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) 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.

(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 (E) 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) An acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(E) 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 (p)(4)(ii)(A) through (D) 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.

(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 of 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.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-26)}$$

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 $E_{s,i,m}$ 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 of this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-27)}$$

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 $E_{s,i,m}$ 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 of this section, develop an emission factor for

each compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section. These emission factors must be calculated annually and used in Equation W–27 of this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \qquad \text{(Eq. W-28)}$$

Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W–27 of 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 of 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 of 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 of 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 of 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), (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 of 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.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \quad \text{(Eq. W-29C)}$$

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.* You must calculate emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility using Equation W–29D of this section.

$$E_{s,i} = Count * EF_{i,s} \quad \text{(Eq. W-29D)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors.

$EF_{i,s}$ = Emission factor for GHG_i. 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.

(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.

(12) *General requirements for calculating volumetric GHG emissions from reciprocating compressors routed to flares.* You must calculate and report emissions from all reciprocating compressor sources that are routed to a flare as specified in paragraphs (p)(12)(i) through (iii) of this section.

(i) Paragraphs (p)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in § 98.236(p).

(q) *Equipment leak surveys.* You must use the methods described in § 98.234(a) to conduct leak detection(s) of equipment leaks from all component types listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to component types in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Component types 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. For industry segments listed in § 98.230(a)(3) through (8), if equipment leaks are detected for component types listed in this paragraph (q), then you must calculate equipment leak emissions per component type per reporting facility using Equation W–30 of this section. For the industry segment listed in § 98.230(a)(8), the results from Equation W–30 are used to calculate population emission factors on a meter/regulator run basis using Equation W–31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(8)(i) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(9) of this section.

$$E_{s,p,i} = GHG_i * EF_{s,p} * \sum_{z=1}^{x_p} T_{p,z} \quad \text{(Eq. W-30)}$$

Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHG_i from specific component type ''p'' (listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1)) in standard (''s'') cubic feet, as specified in paragraphs (q)(1) through (q)(8) of this section.

x_p = Total number of specific component type ''p'' detected as leaking during annual leak surveys.

$EF_{s,p}$ = Leaker emission factor for specific component types listed in Table W–2 through Table W–7 of this subpart.

GHG_i = 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 ; 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, GHG_i equals 1 for CH_4 and 1.1×10^{-2} 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, accounting for time the component was not operational (*i.e.,* not operating under pressure) using engineering estimate based on best available data. If multiple leak detection surveys are conducted in the calendar year, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey), accounting for time the component was not operational using engineering estimate based on best available data. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year, accounting for time the component was not operational using engineering estimate based on best available data.

(1) You must conduct either one leak detection survey in a calendar year or multiple complete leak detection

surveys in a calendar year. The leak detection surveys selected must be conducted during the calendar year.

(2) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–2 of this subpart.

(4) Onshore natural gas transmission compression facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–3 of this subpart.

(5) Underground natural gas storage facilities must use the appropriate default total hydrocarbon leaker emission factors for storage stations in gas service listed in Table W–4 of this subpart.

(6) LNG storage facilities must use the appropriate default methane leaker emission factors for LNG storage components in gas service listed in Table W–5 of this subpart.

(7) LNG import and export facilities must use the appropriate default methane leaker emission factors for LNG terminals components in LNG service listed in Table W–6 of this subpart.

(8) Natural gas distribution facilities must use Equation W–30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W–7 of this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations. 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.

(i) 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.

(ii) Use Equation W–31 of 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)(8)(iii) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \qquad \text{(Eq. W-31)}$$

Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type ''p'' during year ''y'' in standard (''s'') cubic feet, as calculated using Equation W–30 of this section.

p = Seven component types listed in Table W–7 of 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 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)(8)(iii) of this section.

n = Number of years of data, according to paragraph (q)(8)(i) of this section, whose results are used to calculate emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(8)(iii) of this section.

(iii) 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)(8)(i) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 of this section. After the first survey cycle of ''n'' years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year ''y'' and survey results from all previous (n–1) calendar years, such that each annual calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 of 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 of 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 of 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.

(9) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(8)(i) of this section, you must use the meter/regulator run population emission factors calculated using Equation W–31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(r) *Equipment leaks by population count.* This paragraph applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources 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 (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \quad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \quad \text{(Eq. W-32B)}$$

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 component (*e.g.* connector, open-ended line, etc.), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, or distribution service.

$E_{s,MR,i}$ = 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)(9) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations, in standard cubic feet.

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart. Underground natural gas storage facilities must count each component listed in Table W–4 of 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: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W–7 of this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W–1A and W–4 through W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart.

$EF_{s,MR,i}$ = 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.

GHG_i = For onshore petroleum and natural gas production 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; 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, GHG_i equals 1 for CH_4 and $1.1 \times 10^{-2} CO_2$.

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 must use the appropriate default whole gas population emission factors listed in Table W–1A of this subpart. Major equipment and components associated with gas wells are considered gas service components in reference to Table W–1A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W–1A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the calculation methods described in this paragraph (r)(2). The same calculation method must be used for the entire calendar year.

(i) *Component Count Method 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart. For meters/piping, use one meters/piping per well-pad.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B and W–1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(ii) *Component Count Method 2.* Count each component individually for the facility. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(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–4 of this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factor for LNG storage compressors in gas service listed in Table W–5 of this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factor for LNG terminal compressors in gas

service listed in Table W–6 of 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 metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in Table W–7 of this subpart. Below grade transmission-distribution transfer stations must use the emission factor for below grade metering-regulating stations.

(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. Natural gas distribution facilities that do not have above grade transmission-distribution transfer stations are not required to calculate emissions for above grade metering-regulating stations and are not required to report GHG emissions in § 98.236(r)(2)(v).

(s) * * *

(2) Offshore production facilities that are not under BOEMRE jurisdiction must 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).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, you may report the most recently reported emissions data submitted to demonstrate compliance with this subpart of part 98, with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

* * * * *

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to estimate emissions. These emission estimates would be used to report emissions from the facility sources as required in paragraph (s)(1)(i) of this section.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle must use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report 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 paragraphs (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 of this section for conversions of $E_{a,n}$ or conversions of FR_a (whether sub-sonic or sonic).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \qquad \text{(Eq. W-33)}$$

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 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \qquad \text{(Eq. W-34)}$$

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.

* * * * *

(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.

* * * * *

(2) * * *

(iii) *GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression 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 of 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/ft³ for CO_2 and N_2O, and 0.0192 kg/ft³ 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.

* * * * *

(3) Calculate the total annual CO_2 emissions from each EOR injection pump system using Equation W–37 of this section:

* * * * *

$Mass_{CO2}$ = 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.

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(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) * * *

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S_{hl} = Amount of CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel, under standard conditions.

* * * * *

(z) * * *

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C–1 of 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 is natural gas, and is not pipeline quality or has a high heat value of less than 950 Btu per standard cubic feet, 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.

(i) For fuels listed in Table C–1 or a blend containing one or more fuels listed in Table C–1, calculate CO_2, CH_4, and N_2O emissions according to any Tier 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.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore natural gas and petroleum production facilities and at natural gas distribution facilities will be reported according to the requirements specified in § 98.236(z) and not according to the reporting requirements specified in subpart C of this part.

(2) * * *

(iii) * * *

* * * * *

V_a = Volume of gas sent to combustion unit in actual cubic feet, during the year.

Y_{CO2} = Mole fraction of CO_2 constituent in gas sent to combustion unit.

* * * * *

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to combustion unit.

* * * * *

Y_{CH4} = Mole fraction of methane constituent in gas sent to combustion unit.

* * * * *

(vi) * * *

$$Mass_{N2O} = \left(1 \times 10^{-3}\right) \times Fuel \times HHV \times EF \qquad \text{(Eq. W-40)}$$

* * * * *

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Annual mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For field gas or process vent gas, you may use either a default higher heating value of 1.235×10^{-3} mmBtu/scf or a site-specific higher heating value. For natural gas that is not of pipeline quality or that has a high heat value less than 950 Btu per standard cubic foot, use a site-specific higher heating value.

* * * * *

■ 6. Section 98.234 is amended by:

■ a. Revising paragraphs (a) introductory text, (d)(1), and (f);

■ b. Removing and reserving paragraph (g); and

■ c. Adding paragraph (h).

The revisions and additions read as follows:

§ 98.234 Monitoring and QA/QC requirements.

* * * * *

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in § 98.233(k), (o), (p) and (q) that occur during a calendar year.

* * * * *

(d) * * *

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methods relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

* * * * *

(f) *Special reporting provisions for best available monitoring methods in reporting year 2015*—(1) *Best available monitoring methods.* From January 1, 2015 to March 31, 2015, for a facility subject to this subpart, you must use the calculation methodologies and equations in § 98.233 ''Calculating GHG Emissions'', but you may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2015 as specified in paragraphs (f)(2) and (3) of this section. Starting no later than April 1, 2015, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraph (f)(4) of this section. Best available monitoring methods means any of the following methods:

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

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Best available monitoring methods for well-related measurement data.* You may use best available monitoring methods for well-related measurement data identified in paragraphs (f)(2)(i) and (ii) of this section that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart.

(i) If Calculation Method 1 for liquids unloading in § 98.233(f)(1) was used in calendar year 2014 and will be used again in calendar year 2015, the vented natural gas flow rate for any well in a unique tubing diameter group and pressure group combination that has not been previously measured.

(ii) If using Equation W–10A of this subpart to determine natural gas emissions from completions and workovers for representative wells, the initial and average flowback rates (when using Calculation Method 1 in § 98.233(g)(1)(i)) or pressures upstream and downstream of the choke (when using Calculation Method 2 in § 98.233(g)(1)(ii)) for any well in a well type combination that has not been previously measured.

(3) *Best available monitoring methods for emissions measurement.* You may use best available monitoring methods for sources listed in paragraphs (f)(3)(i) and (ii) of this section if the required measurement data cannot reasonably be obtained according to the monitoring and QA/QC requirements of this part.

(i) Centrifugal compressor as found measurements of manifolded emissions from groups of centrifugal compressor sources according to § 98.233(o)(4) and (5), in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(ii) Reciprocating compressor as found measurements of manifolded emissions from groups of reciprocating compressor sources according to § 98.233(p)(4) and (5), in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(4) *Requests for extension of the use of best available monitoring methods beyond March 31, 2015.* You may submit a request to the Administrator to use one or more best available monitoring methods for sources listed in paragraphs (f)(2) and (3) of this section beyond March 31, 2015.

(i) *Timing of request.* The extension request must be submitted to EPA no later than January 31, 2015.

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

(A) A list of specific source types and parameters for which you are seeking use of best available monitoring methods.

(B) For each specific source type for which you are requesting use of best available monitoring methods, a description of the reasons that the needed equipment could not be obtained and installed before April 1, 2015.

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

(iii) *Approval criteria.* To obtain approval to use best available monitoring methods after March 31, 2015, you must submit a request demonstrating to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2015. The use of best available methods under paragraph (f) of this section will not be approved beyond December 31, 2015.

* * * * *

(h) For well venting for liquids unloading, if a monitoring period other than the full calendar year is used to determine the cumulative amount of time in hours of venting for each well (the term ''T_p'' in Equation W–7A and W–7B of § 98.233) or the number of unloading events per well (the term ''V_p'' in Equations W–8 and W–9 of § 98.233), then the monitoring period must begin before February 1 of the reporting year and must not end before December 1 of the reporting year. The end of one monitoring period must immediately precede the start of the next monitoring period for the next reporting year. All production days must be monitored and all venting accounted for.

■ 7. Section 98.235 is revised to read as follows:

§ 98.235 Procedures for estimating missing data.

Except as specified in § 98.233, whenever a value of a parameter is unavailable for a GHG emission calculation required by this subpart (including, but not limited to, if a measuring device malfunctions during unit operation or activity data are not collected), you must follow the procedures specified in paragraphs (a) through (i) of this section, as applicable.

(a) For stationary and portable combustion sources that use the calculation methods of subpart C of this part, you must use the missing data procedures in subpart C of this part.

(b) For each missing value of a parameter that should have been measured quarterly or more frequently using equipment including, but not limited to, a continuous flow meter, composition analyzer, thermocouple, or pressure gauge, you must substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the ''after'' value is not obtained by the end of the reporting year, you may use the ''before'' value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, you must use the first quality-assured value obtained after the missing data period as the substitute data value. A value is quality-assured according to the procedures specified in § 98.234.

(c) For each missing value of a parameter that should have been measured annually, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection.

(d) For each missing value of a parameter that should have been measured biannually (every two years), you must conduct the estimation or measurement activity for those sources as soon as possible in the subsequent calendar year if the estimation or measurement was not made in the appropriate year (first year of data collection and every two years thereafter), until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used to alternate or postpone subsequent biannual emissions estimations or measurements.

(e) For the first 6 months of required data collection, facilities that become newly subject to this subpart W may use best engineering estimates for any data that cannot reasonably be measured or obtained according to the requirements of this subpart.

(f) For the first 6 months of required data collection, facilities that are currently subject to this subpart W and that 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 acquired sources that cannot reasonably be measured or obtained according to the requirements of this subpart.

(g) Unless addressed in another paragraph of this section, for each missing value of any activity data, you must substitute data value(s) using the best available estimate(s) of the parameter(s), based on all applicable and available process or other data (including, but not limited to, processing rates, operating hours).

(h) You must report information for all measured and substitute values of a parameter, and the procedures used to substitute an unavailable value of a parameter per the requirements in § 98.236(bb).

(i) You must follow recordkeeping requirements listed in § 98.237(f).

■ 8. Section 98.236 is revised 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 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 (8) 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 (8) of this section, and each applicable emission source listed in paragraphs (b) through (z) of this section.

(1) *Onshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(1)(i) through (xvii) 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.* 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) *Onshore production storage tanks.* Report the information specified in paragraph (j) of this section.

(ix) *Well testing.* Report the information specified in paragraph (l) of this section.

(x) *Associated natural gas.* Report the information specified in paragraph (m) of this section.

(xi) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(xii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(xiii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(xiv) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xv) *EOR injection pumps.* Report the information specified in paragraph (w) of this section.

(xvi) *EOR hydrocarbon liquids.* Report the information specified in paragraph (x) of this section.

(xvii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(2) *Offshore petroleum and natural gas production.* Report the information specified in paragraph (s) of this section.

(3) *Onshore natural gas processing.* For the equipment/activities specified

in paragraphs (a)(3)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(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) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(v) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vi) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(4) *Onshore natural gas transmission compression.* For the equipment/activities specified in paragraphs (a)(4)(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) *Transmission storage tanks.* Report the information specified in paragraph (k) of this section.

(iv) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(v) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vi) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(5) *Underground natural gas storage.* For the equipment/activities specified in paragraphs (a)(5)(i) through (vi) 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) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(v) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(6) *LNG storage.* For the equipment/activities specified in paragraphs (a)(6)(i) through (v) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(ii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(iv) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(v) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(7) *LNG import and export equipment.* For the equipment/activities specified in paragraphs (a)(7)(i) through (vi) 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) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(v) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(8) *Natural gas distribution.* For the equipment/activities specified in paragraphs (a)(8)(i) through (iii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(ii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(iii) *Equipment leaks by population count.* Report the information specified in paragraph (r) 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 (b)(4) of this section.

(1) The number of natural gas pneumatic devices as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) The total number of devices of each type, determined according to § 98.233(a)(1) and (2).

(ii) If the reported value in paragraph (b)(1)(i) of this section is an estimated value determined according to § 98.233(a)(2), then you must report the information specified in paragraphs (b)(1)(ii)(A) through (C) of this section.

(A) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are counted.

(B) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(2) For each type of pneumatic device, the estimated average number of hours in the calendar year that the natural gas pneumatic devices reported in paragraph (b)(1)(i) of this section were operating in the calendar year (''T_t'' in Equation W–1 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices combined, calculated using Equation W–1 of this subpart and § 98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(4) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined, calculated using Equation W–1 of this subpart and § 98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(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 (4) of this section.

(1) Count of natural gas driven pneumatic pumps.

(2) Average estimated number of hours in the calendar year the pumps were operational (''T'' in Equation W–2 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps combined, calculated according to § 98.233(c)(1) and (2).

(4) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps combined, calculated according to § 98.233(c)(1) and (2).

(d) *Acid gas removal units.* You must indicate whether your facility has any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. If your facility contains any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant, then you must report the information specified in paragraphs (d)(1) and (2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (vi) of this section for each acid gas removal unit.

(i) A unique name or ID number for the acid gas removal unit. For the onshore petroleum and natural gas production industry segment, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

(ii) Total feed rate entering the acid gas removal unit, using a meter or engineering estimate based on process knowledge or best available data, in million cubic feet per year.

(iii) The calculation method used to calculate CO_2 emissions from the acid gas removal unit, as specified in § 98.233(d).

(iv) Whether any CO_2 emissions from the acid gas removal unit are recovered and transferred outside the facility, as specified in § 98.233(d)(11). If any CO_2 emissions from the acid gas removal unit were recovered and transferred outside the facility, then you must report the annual quantity of CO_2, in metric tons CO_2, that was recovered and transferred outside the facility under subpart PP of this part.

(v) Annual CO_2 emissions, in metric tons CO_2, 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)(10) and (11).

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production 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.

(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, then you must report the information specified in paragraphs (d)(2)(i)(A) and (B) of this section.

(A) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit.

(B) Annual volume of gas vented from the acid gas removal unit, in cubic feet.

(ii) If you used Calculation Method 3 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)(ii)(A) through (D) of this section.

(A) Indicate which equation was used (Equation W–4A or W–4B).

(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 or Equation W–4B of this subpart.

(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 or Equation W–4B of this subpart.

(D) The natural gas flow rate used, as specified in Equation W–4A of this subpart, reported as either total annual volume of natural gas flow into the acid gas removal unit in cubic feet at actual conditions; or total annual volume of natural gas flow out of the acid gas removal unit, as specified in Equation W–4B of this subpart, in cubic feet at actual conditions.

(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 (L) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Natural gas feed temperature, in degrees Fahrenheit.

(C) Natural gas feed pressure, in pounds per square inch.

(D) Natural gas flow rate, in standard cubic feet per minute.

(E) Acid gas content of the feed natural gas, in mole percent.

(F) Acid gas content of the outlet natural gas, in mole percent.

(G) Unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(H) Exit temperature of the natural gas, in degrees Fahrenheit.

(I) Solvent pressure, in pounds per square inch.

(J) Solvent temperature, in degrees Fahrenheit.

(K) Solvent circulation rate, in gallons per minute.

(L) Solvent weight, in pounds per gallon.

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day, glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day, 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).

(1) For each glycol dehydrator that has an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day (as specified in § 98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator.

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production industry segment, 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, determined by engineering estimate based on best available data.

(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 stripper gas is used in dehydrator.

(ix) Whether a flash tank separator is used in dehydrator.

(x) Total time the dehydrator is operating, in hours.

(xi) Temperature of the wet natural gas, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas, 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) Whether any dehydrator emissions are vented to a vapor recovery device.

(xvi) Whether any dehydrator emissions are vented to a flare or regenerator firebox/fire tubes. If any emissions are vented to a flare or

regenerator firebox/fire tubes, report the information specified in paragraphs (e)(1)(xvi)(A) through (C) of this section for these emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator, calculated according to § 98.233(e)(6).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator, calculated according to § 98.233(e)(6).

(C) Annual N_2O emissions, in metric tons N_2O, for the dehydrator, calculated according to § 98.233(e)(6).

(xvii) Whether any dehydrator emissions are vented to the atmosphere without being routed to a flare or regenerator firebox/fire tubes. If any emissions are not routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(1)(xvii)(A) and (B) of this section for those emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1), and, if applicable, (e)(5).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, (e)(5).

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only).

(2) For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day (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.

(ii) Whether any dehydrator emissions were vented to a vapor recovery device. If any dehydrator emissions were vented to a vapor recovery device, then you must report the total number of dehydrators at the facility that vented to a vapor recovery device.

(iii) Whether any dehydrator emissions were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a control device(s) other than a vapor recovery device 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 vented to each type of control device.

(iv) Whether any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (D) of this section.

(A) The total number of dehydrators venting to a flare or regenerator firebox/fire tubes.

(B) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(6).

(C) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(6).

(D) Annual N_2O emissions, in metric tons N_2O, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to § 98.233(e)(6).

(v) For dehydrator emissions that were not vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2), (e)(4), and, if applicable, (e)(5), 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 (iii) of this section for the entire facility.

(i) The same information specified in paragraphs (e)(2)(i) through (iv) of this section for glycol dehydrators, and report the information under this paragraph for dehydrators that use desiccant.

(ii) Annual CO_2 emissions, in metric tons CO_2, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(iii) Annual CH_4 emissions, in metric tons CH_4, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(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 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 and uses Calculation Method 2 or 3, then you must report the information specified in paragraph (f)(2) of this section.

(1) For each sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells with plunger lifts and wells without plunger lifts.

(i) Sub-basin ID.

(ii) Well tubing diameter and pressure group ID.

(iii) Plunger lift indicator.

(iv) Count of wells vented to the atmosphere for the sub-basin/well tubing diameter and pressure group.

(v) Percentage of wells for which the monitoring period used to determine the cumulative amount of time venting was not the full calendar year.

(vi) Cumulative amount of time wells were vented (sum of ''T_p'' from Equation W–7A or W–7B of this subpart), in hours.

(vii) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells in the sub-basin/well tubing diameter and pressure group.

(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 (E) of this section for each individual well not using a plunger lift that was tested during the year.

(A) API Well 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.

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (E) of this section for each individual well using a plunger lift that was tested during the year.

(A) API Well 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.

(2) For each sub-basin for which you used Calculation Method 2 or 3 (as specified in § 93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in (f)(2)(i) through (x) of this section. Report information separately for each calculation method.

(i) Sub-basin ID.

(ii) Calculation method.

(iii) Plunger lift indicator.

(iv) Number of wells vented to the atmosphere.

(v) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells.

(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) For wells without plunger lifts, the average internal casing diameter, in inches.

(x) For wells with plunger lifts, the average internal tubing diameter, in inches.

(g) *Completions and workovers with hydraulic fracturing.* You must indicate whether your facility had any gas well completions or workovers with hydraulic fracturing during the calendar year. If your facility had gas well completions or workovers with hydraulic fracturing during the calendar year, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each sub-basin and well type combination. Report information separately for completions and workovers.

(1) Sub-basin ID.

(2) Well type combination.

(3) Number of completions or workovers in the sub-basin and well type combination category.

(4) Calculation method used.

(5) If you used Equation W–10A to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) and (ii) of this section.

(i) Cumulative gas flowback time, in hours, 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). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the API Well Number(s) for the well(s) included in the number.

(ii) For the measured well(s), the flowback rate, in standard cubic feet per hour (average of ''$FR_{s,p}$'' values used in Equation W–12A). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured flowback rate during well completion or workover and the API Well Number(s) for the well(s) included in the measurement.

(6) If you used Equation W–10B to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) and (ii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin (''$FV_{s,p}$'' in Equation W–10B).

(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, for each well in the sub-basin (''$FR_{p,i}$'' in Equation W–10B).

(7) Annual gas emissions, in standard cubic feet (''$E_{s,n}$'' in Equation W–10A or W–10B).

(8) Annual CO_2 emissions, in metric tons CO_2.

(9) Annual CH_4 emissions, in metric tons CH_4.

(10) If the well emissions were vented to a flare, then you must report the total N_2O emissions, in metric tons N_2O.

(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 sub-basin with gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Sub-basin ID.

(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 in the sub-basin category (the sum of all ''T_p'' for completions that vented to the atmosphere as used in Equation W–13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all ''V_p'' used in Equation W–13B). 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 that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the API Well Number(s) for the well(s) included in the measurement.

(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 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 for completions that vented directly to the atmosphere, converted to mass emissions according to § 98.233(h)(1)).

(2) For each sub-basin with gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (vii) of this section.

(i) Sub-basin ID.

(ii) Number of well completions that flared gas.

(iii) Total number of hours that gas vented to a flare during venting for all completions in the sub-basin category (the sum of all ''T_p'' for completions that vented to a flare from Equation W–13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all ''V_p'' from Equation W–13B). 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 that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the API Well Number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(vii) Annual N_2O emissions, in metric tons N_2O, that resulted from completions that flared gas calculated according to § 98.233(h)(2).

(3) For each sub-basin with gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Sub-basin ID.

(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 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 for workovers that vented directly to the atmosphere, converted to mass emissions as specified in § 98.233(h)(1)).

(4) For each sub-basin with gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) through (v) of this section.

(i) Sub-basin ID.

(ii) Number of workovers that flared gas.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers that flared gas, calculated as specified in § 98.233(h)(2).

(v) Annual N_2O emissions, in metric tons N_2O per year, that resulted from workovers that flared gas calculated as specified in § 98.233(h)(2).

(i) *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.

(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), then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event.

(i) 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 of this subpart, for all unique physical volumes for the equipment or event type).

(ii) Annual CO_2 emissions for the equipment or event type, in metric tons CO_2, calculated according to § 98.233(i)(2)(iii).

(iii) 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) and (ii) of this section for the facility.

(i) Annual CO_2 emissions from all blowdown vent stacks at the facility 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).

(ii) Annual CH_4 emissions from all blowdown vent stacks at the facility 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).

(j) *Onshore production storage tanks.* You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2, and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xiv) of this section for each sub-basin and by calculation method.

(i) Sub-basin ID.

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual oil volume from gas-liquid separators and direct from wells that is sent to applicable onshore production storage tanks, in barrels. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date

specified in § 98.236(cc) the total volume of oil from all wells and the API Well Number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator pressure, in pounds per square inch gauge.

(vi) The average sales oil or stabilized oil API gravity, in degrees.

(vii) The minimum and maximum concentration (mole fraction) of CO_2 in flash gas from onshore production storage tanks.

(viii) The minimum and maximum concentration (mole fraction) of CH_4 in flash gas from onshore production storage tanks.

(ix) The number of wells sending oil to gas-liquid separators or directly to atmospheric tanks.

(x) The number of atmospheric tanks.

(xi) An estimate of the number of atmospheric tanks, not on well-pads, receiving your oil.

(xii) If any emissions from the atmospheric tanks at your facility were controlled with vapor recovery systems, then you must report the information specified in paragraphs (j)(1)(xii)(A) through (E) of this section.

(A) The number of atmospheric tanks that control emissions with vapor recovery systems.

(B) Total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(C) Total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(D) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks equipped with vapor recovery systems.

(E) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks equipped with vapor recovery systems.

(xiii) If any atmospheric tanks at your facility vented gas directly to the atmosphere without using a vapor recovery system or without flaring, then you must report the information specified in paragraphs (j)(1)(xiii)(A) through (C) of this section.

(A) The number of atmospheric tanks that vented gas directly to the atmosphere without using a vapor recovery system or without flaring.

(B) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere.

(C) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere.

(xiv) If you controlled emissions from any atmospheric tanks at your facility with one or more flares, then you must report the information specified in paragraphs (j)(1)(xiv)(A) through (D) of this section.

(A) The number of atmospheric tanks that controlled emissions with flares.

(B) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with one or more flares.

(C) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with one or more flares.

(D) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with one or more 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 (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3.

(A) The total annual oil throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production less than 10 barrels per day and that send oil to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual oil throughput from all wells and the API Well Number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of oil throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

(D) The number of atmospheric tanks in the basin.

(E) The number of wells with gas-liquid separators (''Count'' from Equation W–15 of this subpart) in the basin.

(F) The number of wells without gas-liquid separators (''Count'' from Equation W–15 of this subpart) in the basin.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin with atmospheric tanks whose emissions were calculated using Calculation Method 3 and that did not control emissions with flares.

(A) Sub-basin ID.

(B) The number of atmospheric tanks in the sub-basin that did not control emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin that did not control emissions with flares, calculated using Equation W–15 of this subpart and adjusted for vapor recovery, if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin that did not control emissions with flares, calculated using Equation W–15 of this subpart and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin with atmospheric tanks whose emissions were calculated using Calculation Method 3 and that controlled emissions with flares.

(A) Sub-basin ID.

(B) The number of atmospheric tanks in the sub-basin that controlled emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with flares.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with flares.

(E) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with flares.

(3) If you used Calculation Method 1 or Calculation Method 2, 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 (iv) of this section for each sub-basin.

(i) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(ii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the ''T_n'' values used in Equation W–16 of this subpart).

(iii) 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 of this subpart.

(iv) 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 of this subpart.

(k) *Transmission storage tanks.* You must indicate whether your facility

contains any transmission storage tanks. If your facility contains at least one transmission storage tank, then you must report the information specified in paragraphs (k)(1) through (3) of this section for each transmission storage tank vent stack.

(1) For each transmission 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 transmission storage tank vent stack.

(ii) Method used to determine if dump valve leakage occurred.

(iii) Indicate whether scrubber dump valve leakage occurred for the transmission storage tank vent according to § 98.233(k)(2).

(iv) Indicate if there is a flare attached to the transmission storage tank vent stack.

(2) If scrubber dump valve leakage occurred for a transmission 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 transmission storage vent stack where scrubber dump valve leakage occurred.

(i) Method 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).

(3) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii), and the vent stack vented to a flare during the calendar year, then you must report the information specified in paragraphs (k)(3)(i) through (vi) of this section.

(i) Method used to measure the leak rate.

(ii) Measured leakage rate (average leak rate from a continuous flow measurement device) in standard cubic feet per hour.

(iii) Duration of time that flaring occurred in hours, as defined in § 98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from flaring gas, calculated according to § 98.233(k)(5).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from flaring gas, calculated according to § 98.233(k)(5).

(vi) Annual N_2O emissions, in metric tons N_2O, that resulted from flaring gas, calculated according to § 98.233(k)(5).

(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) If you used Equation W–17A to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are not vented to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vi) of this section.

(i) Number of wells tested in the calendar year.

(ii) Average number of well testing days per well for well(s) tested in the calendar year.

(iii) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(iv) Average flow rate for well(s) tested, in barrels of oil per day. 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 that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.

(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).

(2) If you used Equation W–17A to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are vented to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (vii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Average number of well testing days per well for well(s) tested in the calendar year.

(iii) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(iv) Average flow rate for well(s) tested, in barrels of oil per day. 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 that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.

(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).

(vii) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(l).

(3) If you used Equation W–17B to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not vented to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (v) of this section.

(i) Number of wells tested in the calendar year.

(ii) Average number of well testing days per well for well(s) tested in the calendar year.

(iii) Average annual production rate for well(s) tested, in actual cubic feet per day. 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 that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(4) If you used Equation W–17B to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were vented to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (vi) of this section.

(i) Number of wells tested in calendar year.

(ii) Average number of well testing days per well for well(s) tested in the calendar year.

(iii) Average annual production rate for well(s) tested, in actual cubic feet

per day. 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 that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(l).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(l).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(l).

(m) *Associated natural gas.* You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented or flared during the calendar year, then you must report the information specified in paragraphs (m)(1) through (8) of this section for each sub-basin.

(1) Sub-basin ID.

(2) Indicate whether any associated gas was vented directly to the atmosphere without flaring.

(3) Indicate whether any associated gas was flared.

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil (average of the ''GOR'' values used in Equation W–18 of this subpart).

(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 of this subpart). 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 API Well Number(s) for the well(s) included in the measurement.

(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 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells 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 API Well Number(s) for the well(s) included in the measurement.

(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 (iii) of this section for each sub-basin.

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(3) and (4).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(3) and (4).

(8) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(8)(i) through (iv) of this section for each sub-basin.

(i) Total number of wells for which associated gas was flared.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(5).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(5).

(iv) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(m)(5).

(n) *Flare stacks.* You must indicate if your facility contains any flare stacks. You must report the information specified in paragraphs (n)(1) through (12) of this section for each flare stack at your facility, and for each industry segment applicable to your facility.

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production industry segment, 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) Indicate whether the flare stack has a continuous flow measurement device.

(3) Indicate whether the flare stack has a continuous gas composition analyzer on feed gas to the flare.

(4) Volume of gas sent to the flare, in standard cubic feet (''V_s'' in Equations W–19 and W–20 of this subpart).

(5) Fraction of the feed gas sent to an un-lit flare (''Z_u'' in Equation W–19 of this subpart).

(6) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare.

(7) Mole fraction of CH_4 in the feed gas to the flare (''X_{CH4}'' in Equation W–19 of this subpart).

(8) Mole fraction of CO_2 in the feed gas to the flare (''X_{CO2}'' in Equation W–20 of this subpart).

(9) Annual CO_2 emissions, in metric tons CO_2 (refer to Equation W–20 of this subpart).

(10) Annual CH_4 emissions, in metric tons CH_4 (refer to Equation W–19 of this subpart).

(11) Annual N_2O emissions, in metric tons N_2O (refer to Equation W–40 of this subpart).

(12) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used to measure emissions from the flare, then you are not required to report N_2O and CH_4 emissions for the flare stack.

(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 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 (xiv) of this section for each centrifugal compressor located at your facility.

(i) Unique name or ID for the centrifugal compressor.

(ii) Hours in operating-mode.

(iii) Hours in not-operating-depressurized-mode.

(iv) Indicate whether the compressor was measured in operating-mode.

(v) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(vii) Indicate which, if any, compressor sources are routed to a flare.

(viii) Indicate which, if any, compressor sources have vapor recovery.

(ix) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(x) Indicate whether the compressor has blind flanges installed and associated dates.

(xi) Indicate whether the compressor has wet or dry seals.

(xii) If the compressor has wet seals, the number of wet seals.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(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)(i) of this section.

(B) Centrifugal compressor source (wet 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 (fuel or thermal oxidizer), or vapor recovery.

(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, 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, 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 was used to calculate emissions in Equation W–22, 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).

(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).

(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.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production must report the information specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Number of centrifugal compressors that have wet seal oil degassing vents.

(ii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with wet seal oil degassing vents.

(iii) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with 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 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 (xiv) of this section for each reciprocating compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) Indicate whether the compressor was measured in operating-mode.

(vi) Indicate whether the compressor was measured in standby-pressurized-mode.

(vii) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(viii) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(ix) Indicate which, if any, compressor sources are routed to a flare.

(x) Indicate which, if any, compressor sources have vapor recovery.

(xi) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(xii) Indicate whether the compressor has blind flanges installed and associated dates.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(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 (fuel or thermal oxidizer), or vapor recovery.

(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 flare, combustion, or vapor recovery, 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, 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 was used to calculate emissions in Equation W–27, 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).

(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).

(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.* Reciprocating compressors in onshore petroleum and natural gas production must report the information specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Number of reciprocating compressors.

(ii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors.

(iii) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors.

(q) *Equipment leak surveys.* If your facility is subject to the requirements of § 98.233(q), then you must report the information specified in paragraphs (q)(1) and (2) of this section. 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) and (ii) of this section.

(i) Except as specified in paragraph (q)(1)(ii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(ii) 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.

(2) You must indicate whether your facility contains any of the component types listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), or (i)(1), 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)(iii), (iv), and (v) of this section.

(i) Component type.

(ii) Total number of the surveyed component type that were identified as leaking in the calendar year (''x_p'' in Equation W–30 of this subpart for the component type).

(iii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of ''$T_{p,z}$'' from Equation W–30 of this subpart for the component type).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using Equation W–30 (for surveyed components only).

(v) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using Equation W–30 (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 of this subpart, 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 of this subpart, 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 of this subpart, 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 of this subpart, 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 of this subpart).

(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 of this subpart).

(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 of this subpart).

(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 of this subpart).

(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.

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of this subpart. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W–32A of this subpart that is located at your facility. Onshore petroleum and natural gas production facilities must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately by component type, service type, and geographic location (*i.e.,* Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities must report the component type, service type and geographic location.

(ii) Total number of the emission source type at the facility (''$Count_e$'' in Equation W–32A of this subpart).

(iii) Average estimated time that the emission source type was operational in the calendar year, in hours (''T_e'' in Equation W–32A of this subpart).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the emission source type.

(v) 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 of this subpart).

(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 of this subpart).

(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) Onshore petroleum and natural gas production facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

(i) Calculation method used.

(ii) Onshore petroleum and natural gas production facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W–1B and W–1C of this subpart.

(A) An indication of whether the facility contains the major equipment type.

(B) If the facility does contain the equipment type, the count of the major equipment type.

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for each emission source type listed in the most recent BOEMRE study.

(1) Annual CO_2 emissions, in metric tons CO_2.

(2) Annual CH_4 emissions, in metric tons CH_4.

(3) 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 (''V_v'' in Equation W–37 of this subpart).

(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 (''R_c'' in Equation W–37 of this subpart).

(7) Mass fraction of CO_2 in critical phase EOR injection gas (''GHG_{CO2}'' in Equation W–37 of this subpart).

(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 of this subpart).

(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 of this subpart).

(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 (''$Mass_{CO2}$'' in Equation W–38 of this subpart).

(y) [Reserved]

(z) *Combustion equipment at onshore petroleum and natural gas production facilities and natural gas distribution facilities.* If your facility is required by § 98.232(c)(22) or (i)(7) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraphs (a)(1)(xvii) or (a)(8)(i) of this section. If your facility contains any combustion units subject to reporting according to paragraphs (a)(1)(xvii) or (a)(8)(i) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

(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) and (ii) of this section for each unit type.

(i) The type of combustion unit.

(ii) 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. If your facility contains: External fuel combustion units with a rated heat capacity greater than 5 mmBtu/hr; 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, then you must report the information specified in paragraphs (z)(2)(i) through (vi) of this section for each combustion unit type and fuel type combination.

(i) The type of combustion unit.

(ii) The type of fuel combusted.

(iii) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(z)(1) and (2).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) and (2).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) and (2).

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (9) of this section, for each applicable industry segment, by using best available data. 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 (ii) 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.

(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 gas produced in the calendar year for sales, in thousand standard cubic feet.

(C) The quantity of crude oil and condensate produced in the calendar year for sales, 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 taken out of production, *i.e.,* plugged and abandoned) .

(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 taken out of production (*i.e.,* plugged and abandoned) 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.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) and (ii) of this section.

(i) The total quantity of gas handled at the offshore platform in the calendar year, in thousand standard cubic feet, including production volumes and volumes transferred via pipeline from another location.

(ii) The total quantity of oil and condensate handled at the offshore platform in the calendar year, in barrels, including production volumes and volumes transferred via pipeline from another location.

(3) For natural gas processing, report the information specified in paragraphs (aa)(3)(i) through (vii) of this section.

(i) The quantity of natural gas received at the gas processing plant 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.

(4) For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.

(i) The quantity of 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 gas withdrawn from storage 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 in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported 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 in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(9) For natural gas distribution, report the quantities specified in paragraphs (aa)(9)(i) through (vii) 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 in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas delivered to end users, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(v) The quantity of natural gas transferred to third parties such as other LDCs or pipelines, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(vi) The quantity of natural gas consumed by the LDC for operational purposes, in thousand standard cubic feet.

(vii) The estimated quantity of gas stolen in the calendar year, in thousand standard cubic feet.

(bb) For any missing data procedures used, report the information in § 98.3(c)(8) 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) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4)(iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

■ 9. Section 98.237 is amended by adding paragraph (f) to read as follows:

§ 98.237 Records that must be retained.

* * * * *

(f) For each time a missing data procedure was used, keep a record listing the emission source type, a description of the circumstance that resulted in the need to use missing data procedures, the missing data provisions in § 98.235 that apply, the calculation or analysis used to develop the substitute value, and the substitute value.

■ 10. Section 98.238 is amended by:

■ a. Adding a definition for ''Associated gas venting or flaring'' in alphabetical order;

■ b. Removing the definition for ''Component'';

■ c. Adding definitions for ''Compressor mode'' and ''Compressor source'' in alphabetical order;

■ d. Removing the definitions for ''Equipment leak'' and ''Equipment leak detection'';

■ e. Adding definitions for ''Manifolded compressor source'' and ''Manifolded group of compressor sources'' in alphabetical order;

■ f. Revising the definition for ''Meter/regulator run'';

■ g. Adding definitions for ''Reduced emissions completion'' and ''Reduced emissions workover'' in alphabetical order; and

■ h. Revising the definition for ''Sub-basin category, for onshore natural gas production''.

The revisions and additions read as follows:

§ 98.238 Definitions.

* * * * *

Associated gas venting or flaring means the venting or flaring of natural gas which originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. This does not include venting or flaring resulting from activities that are reported elsewhere, including tank venting, well completions, and well workovers.

* * * * *

Compressor mode means the operational and pressurized status of a compressor. For a centrifugal compressor, ''mode'' refers to either operating-mode or not-operating-depressurized-mode. For a reciprocating compressor, ''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, and wet seal oil degassing 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.

* * * * *

Manifolded compressor source means a compressor source (as defined in this section) that is manifolded to a common vent that routes gas from multiple compressors.

Manifolded group of compressor sources means a collection of any combination of manifolded compressor sources (as defined in this section) that are manifolded to a common vent.

Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow, or both, in the natural gas distribution industry segment. At least one meter, at least one regulator, or any combination of both on a single run of piping is considered one meter/regulator run.

* * * * *

Reduced emissions completion means a well completion following hydraulic fracturing where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions completion may occur.

Reduced emissions workover means a well workover with hydraulic fracturing (*i.e.,* refracturing) where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions workover may occur.

* * * * *

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight gas reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce only from high permeability gas, shale gas, coal seam, or other tight gas reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids (with or without gas) and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight gas reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

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