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

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2011–0512; FRL–9906–85–OAR]

RIN 2060–AR96

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing revisions and confidentiality determinations for the petroleum and natural gas systems source category and the general provisions of the Greenhouse Gas Reporting Rule. In particular, the EPA is proposing to revise certain calculation methods, amend certain monitoring and data reporting requirements, clarify certain terms and definitions, and correct certain technical and editorial errors that have been identified during the course of implementation. This action also proposes confidentiality determinations for new or substantially revised data elements contained in these proposed amendments, as well as proposes a revised confidentiality determination for one existing data element.

DATES: *Comments.* Comments must be received on or before April 24, 2014.

Public Hearing. The EPA does not plan to conduct a public hearing unless requested. To request a hearing, please contact the person listed in the following **FOR FURTHER INFORMATION CONTACT** section by March 17, 2014. If requested, the hearing will be conducted on March 25, 2014, in the Washington, DC area. The EPA will provide further information about the hearing on the Greenhouse Gas Reporting Rule Web site, *http://www.epa.gov/ghgreporting/index.html* if a hearing is requested.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2011–0512 by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Email: GHG_Reporting_Rule_Oil_And_Natural_Gas@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2011–0512 or RIN No. 2060–AR96 in the subject line of the message.
- *Fax:* (202) 566–9744.
- *Mail:* Environmental Protection Agency, EPA Docket Center (EPA/DC), Mailcode 28221T, Attention Docket ID No. OAR–2011–0512, 1200 Pennsylvania Avenue NW., Washington, DC 20460.
- *Hand/Courier Delivery:* EPA Docket Center, Public Reading Room, William Jefferson Clinton (WJC) West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. Such deliveries are accepted only during the normal hours of operation of the Docket Center, and special arrangements should be made for deliveries of boxed information.

Additional Information on Submitting Comments: To expedite review of your comments by agency staff, you are encouraged to send a separate copy of your comments, in addition to the copy you submit to the official docket, to Carole Cook, U.S. EPA, Office of Atmospheric Programs, Climate Change Division, Mail Code 6207–J, 1200 Pennsylvania Avenue NW., Washington, DC 20460, telephone (202) 343–9263, email address: *GHGReportingRule@epa.gov.*

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2011–0512, Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute.

Should you choose to submit information that you claim to be CBI, clearly mark the part or all of the information that you claim to be CBI. For information that you claim to be CBI in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI to only the mail or hand/courier delivery address listed above, attention: Docket ID No. EPA–HQ–OAR–2011–0512. If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: 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., 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–6207J), 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/*

index.html. 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 today's proposal will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on EPA's Greenhouse Gas Reporting Rule Web site at *http://www.epa.gov/ghgreporting/index.html*.

SUPPLEMENTARY INFORMATION:

Regulated Entities. The Administrator determined that this action 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''). These are proposed amendments to existing regulations. If finalized, these amended regulations would affect owners or operators of petroleum and natural gas systems that directly emit greenhouse gases (GHGs). Regulated categories and entities 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	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution.
	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Other types of facilities 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.

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

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
EOR enhanced oil recovery
EPA U.S. Environmental Protection Agency
FERC Federal Energy Regulatory Commission
FR Federal Register
GHG greenhouse gas
GOR gas to oil ratio
GWP global warming potential
LNG liquefied natural gas
MMscf million standard cubic feet per day
N_2O nitrous oxide
NAICS North American Industry Classification System
NGL natural gas liquids
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
QA/QC quality assurance/quality control
RFA Regulatory Flexibility Act
scf standard cubic feet
TSD Technical Support Document
UIC underground injection control
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995

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

I. Background

A. Organization of This Preamble

The first section of this preamble provides background information regarding the origin of the proposed 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 proposed revisions to 40 CFR part 98, subpart W (hereafter referred to as ''subpart W''). Section III of this preamble discusses proposed confidentiality determinations for new or substantially revised (i.e., requiring additional or different data to be reported) data reporting elements, as well as a proposed revised confidentiality determination for one existing data element. Section IV of this preamble discusses the impacts of the proposed amendments to subpart W. Finally, Section V of this preamble describes the statutory and executive order requirements applicable to this action.

B. Background on the Proposed Action

On October 30, 2009, the EPA published Part 98 for collecting information regarding greenhouse gases (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 20, 2010 finalizing the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458) (hereafter referred to as ''the final subpart W rule''). Following promulgation, the EPA finalized 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, Nov. 29, 2013).

In this action, the EPA is proposing to make certain revisions to the petroleum and natural gas systems source category GHG reporting requirements (Part 98, subpart W) and one clarifying edit to a definition in the general provisions source category (Part 98, subpart A). The proposed changes revise certain calculation methods, amend certain monitoring and data reporting requirements, clarify certain terms and definitions, and correct certain technical and editorial errors identified during the course of implementation. The proposed revisions were identified from the verification of annual reports, review of Best Available Monitoring Method (BAMM) request submittals, and questions raised by reporting entities. In conjunction with this action, we are proposing confidentiality determinations for the new and substantially revised (i.e., requiring additional or different data to be reported) data elements contained in these proposed amendments, as well as proposing a revised confidentiality determination for one existing data element.

C. Legal Authority

The EPA is proposing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 final GHG reporting rule (74 FR 56260, October 30, 2009), CAA section 114(a)(1) provides the EPA broad authority to require the information proposed to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out 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, the EPA is proposing confidentiality determinations for proposed new or substantially revised data elements in subpart W, as well as proposing a revised confidentiality determination for one existing data element, under its authorities provided in sections 114, 301, and 307 of the CAA. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except where information 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 would these amendments apply to 2014 and 2015 reports?

The EPA is planning to address the comments we receive on these proposed changes and publish the final amendments before the end of 2014. If finalized, these amendments would become effective on January 1, 2015. Facilities would therefore be required to follow the revised methods in subpart W, as amended, to calculate emissions beginning January 1, 2015 (i.e., beginning with the 2015 reporting year). The first annual reports of emissions calculated using the amended requirements would be those submitted by March 31, 2016, which would cover the 2015 reporting year. For the 2014 reporting year, reporters would continue to calculate emissions and other relevant data for the reports that are submitted according to the requirements of 40 CFR part 98 that are applicable to the 2014 reporting year (i.e. those currently in effect).

II. Revisions and Other Amendments

The amendments to subpart W that the EPA is proposing include the following types of changes:

• Changes to clarify or simplify calculation methods for certain sources at a facility, and reduce some of the burden associated with data collection and reporting.

• 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 for each source type.

• Other amendments and revisions identified as a result of working with the affected sources during rule implementation and outreach.

In addition to the specific revisions or amendments discussed in this section of the preamble, the EPA is proposing several minor technical revisions to subpart W to improve readability, to create consistency in terminology, and/or to correct typographical or other errors. These proposed revisions contained in the proposed regulatory text are further explained in the memorandum, ''Proposed Minor Technical Corrections to Subpart W, Petroleum and Natural Gas Systems, in the Greenhouse Gas Reporting Program'' in Docket ID No. EPA–HQ–OAR–2011–0512. The EPA invites public comment on the revisions identified in this memorandum, as well as those outlined in this preamble.

A. Proposed Revisions To Provide Consistency Throughout Subpart W

1. Consistency in Units of Measure for Emissions Reporting

Currently, subpart W requires that reported GHG emissions be expressed in metric tons of CO_2 equivalent (CO_2e). The EPA is proposing to amend 40 CFR 98.236 to revise the reporting of GHG emissions from units of metric tons of CO_2e of each reported GHG to metric tons of each reported GHG. These proposed changes would increase consistency between the reporting requirements for subpart W and the rest of Part 98, because other subparts of Part 98 generally require the reporting of metric tons of individual GHGs instead of metric tons of CO_2e. Reporters would use the global warming potentials (GWPs) in Table A–1 of 40 CFR Part 98, subpart A, as required in 40 CFR 98.2(b)(4), to calculate annual emissions aggregated for all GHGs from all applicable source categories in metric tons of CO_2e for their annual reports.

Specifically, we are proposing to revise 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 (N2O), as applicable, instead of reporting each gas in metric tons of CO_2e. We are also proposing to revise certain calculation methods that require the calculation of emissions in CO_2e. For example, subpart W total GHG emissions are calculated using equations that reference GWPs (Equations W–36 and W–40). We are proposing to amend each equation referencing GWPs separately to remove the conversion factors and GWPs that are built into the equations, and allow for calculation of individual GHG emissions in metric tons.

The proposed revisions reduce the likelihood of errors and inconsistencies, because it reduces the number of calculations that need to be completed by reporters and removes some variability in how different reporters may complete these calculations (e.g., a reporter could inadvertently use the wrong GWP). The proposed changes would also simplify analysis of emissions on a GHG-specific basis, which would facilitate the verification of reported data. In addition, this proposed change would align subpart W with the manner of reporting for most other subparts of Part 98.

2. Onshore Production Source Category Definition

We are proposing to revise 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. The proposed amendments clarify the types of emission sources in the onshore petroleum and natural gas production source category to which the reporting requirements of subpart W apply. Specifically, we are proposing to add references to engines, boilers, heaters, flares, separation and processing equipment, and maintenance and repair equipment and to remove references to gravity separation equipment and auxiliary non-transportation-related equipment. Thus, the first sentence of 40 CFR 98.230(a)(2) is proposed to read as follows: ''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, maintenance and repair 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).'' The references to gravity separation equipment and auxiliary non-transportation-related equipment in the current rule are redundant with other sources specified in the definition. The proposed amendments do not subject new emission sources to the reporting requirements and do not remove sources currently covered from the reporting requirements, but rather provide a more accurate description of the industry segment for purposes of GHG reporting.

3. Definition of Sub-Basin Category

The EPA is proposing to revise the definition of sub-basin category at 40 CFR 98.238 to clarify coverage for purposes of GHG reporting due to issues identified during implementation. Specifically, we are proposing to define 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 >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.'' The EPA is proposing these edits to clarify that ''tight gas reservoir rock'' generally refers to tight reservoir rock formations that produce gas, and not tight reservoir rock formations that produce only oil, and that wells that produce liquids in a sub-basin from formations other than high permeability gas, shale gas, coal seam, or other tight gas reservoir rock are considered oil wells.

B. Proposed Changes to Calculation Methods and Reporting Requirements

This section describes proposed changes or corrections to calculation methods and reporting requirements. In general, the proposed revisions to calculation methods would provide greater flexibility and potentially reduce burden to facilities (e.g., by increasing options for calculating emissions from compressors), and increase clarity and congruency of calculation and reporting requirements (e.g., by clarifying which reporting requirements apply to which calculation methods). The EPA is also proposing minor technical revisions to the calculation methods of subpart W, such as making equation variables and definitions consistent across multiple equations that identify the same parameters, or clarifying requirements that have caused confusion. Please see the memo, ''Proposed Minor Technical Corrections to Subpart W, Petroleum and Natural Gas Systems, in the Greenhouse Gas Reporting Program'' in Docket ID No. EPA–HQ–OAR–2011–0512, for more information on the minor technical revisions included in this proposal.

We are also proposing revisions to the reporting requirements in 40 CFR 98.236. The proposed revisions would restructure the reporting requirements, make reporting requirements consistent with the calculation methods, clarify the data elements to be reported, and improve data utility. In the current subpart W rule, slight inconsistencies between the calculation and the reporting sections have caused confusion among some reporters. In order to improve the quality of the data reported, we are proposing to revise reporting requirements that more clearly align with the calculation methods for each source type.

We are proposing to reorganize the reporting section by source type (e.g., natural gas pneumatic device venting, acid gas removal vents, etc.) and, for each industry segment, list which source types must be reported. These proposed changes would clarify the reporting requirements for each industry segment and streamline verification by reducing the amount of correspondence with facilities during verification regarding required data elements that were not reported. Although the proposed reporting requirements appear lengthier, the revisions separate the requirements into discrete reporting elements in order to facilitate reporting and improve data collection. The proposed revisions to the reporting requirements in 40 CFR 98.236 will clarify which data elements are required to be reported for which facilities. For example, in reviewing the current subpart W reporting forms, if a reporter left certain fields blank in the reporting form (e.g., emissions from flaring), the EPA has been unable to discern whether the field was left blank intentionally. Because the proposed 40 CFR 98.236 would clearly define each data element for each emission source in each industry segment that must be reported, it would clarify which fields in the subpart W reporting form should be populated. In some cases, we are also proposing to add additional data elements to improve the quality of the data reported. The reporting of these proposed data elements would improve verification of reported emissions and reduce the amount of correspondence with reporters that is associated with follow-up and revision of annual reports. In nearly all cases, the new data elements are based on data that are already collected by the reporter or are readily available to the reporter, and would not require additional monitoring or data collection. For additional information on the proposed changes to the reporting section, see the memo, ''Proposed Revisions to the Subpart W Reporting Requirements'' in Docket Id. No. EPA–HQ–OAR–2011–0512.

1. Natural Gas Pneumatic Device Venting

The EPA is proposing to revise the calculation method for natural gas pneumatic device venting to expand the use of site-specific data on gas compositions, if available, for facilities in the onshore natural gas transmission compression and underground natural gas storage industry segments. The final subpart W rule provides default natural gas compositions of 95 percent CH_4 and 1 percent CO_2 for onshore natural gas transmission compression and underground natural gas storage, when calculating CH_4 and CO_2 volumetric emissions from transmission storage tanks (transmission compression), blowdown vent stacks (transmission compression), and compressor venting (40 CFR 98.233(u)(2)(iii) and (iv)). The provisions of 40 CFR 98.233(u)(2) only allow default gas compositions to be used, unless otherwise specified in 40 CFR 98.233(u)(2) (i.e., for onshore production and natural gas processing).

We are proposing to allow either the use of site-specific composition data for natural gas transmission compression and underground natural gas storage facilities or the use of a default gas composition (95 percent CH_4 and 1 percent CO_2). Specifically, we are proposing to revise the parameter ''GHGi'' in Equation W–1 to remove the default gas composition for CH_4 and CO_2 and to direct reporters to use the concentrations determined as specified in 40 CFR 98.233(u)(2)(i), (iii), and (iv). This amendment addresses reporter concerns and improves data quality for those using site-specific data. The proposed changes are consistent with provisions for other applicable emission sources at natural gas transmission compression and underground storage facilities and would allow a consistent gas composition to be used for all sources at a facility. The calculation still must be conducted in much the same way that is currently required; however, we are proposing that reporters be allowed to use site-specific data if they are available. Therefore, the EPA does not anticipate that this proposed change will significantly affect the reporting burden. The EPA requests comment on whether the use of site-specific composition data for calculating emissions should be required or optional. The EPA also requests comment and specific details on when, if ever, a facility would not have site-specific gas composition data available.

We are also proposing to revise the natural gas pneumatic device venting calculations (40 CFR 98.233(a)(1), (a)(2), and (a)(3)) to simplify how ''$Count_t$'' of Equation W–1 (total number of natural gas pneumatic devices) must be calculated each year as new devices are added. The revisions clarify that for all industry segments, the reported number of devices must represent the total number of devices for the reporting year. For the onshore petroleum and natural gas production industry segment, reporters would continue to have the option in the first two reporting years to estimate ''$Count_t$'' using engineering estimates.

2. Acid Gas Removal Vents

For acid gas removal vents, we are proposing minor clarifying edits to 40 CFR 98.233(d) to clearly label each calculation method and to clarify provisions by providing references to equations where appropriate. We are also proposing to revise 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. We are also proposing to specify 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.

3. Dehydrators

We are proposing to revise the dehydrator vents source by renumbering and revising the dehydrator calculation method for desiccant dehydrators in order to clarify the adjustment of emissions to account for venting to a vapor recovery system or to a flare (40 CFR 98.233(e)). The proposed amendments provide for the adjustment of emissions vented to a vapor recovery system or flare (40 CFR 98.233(e)(5) and (e)(6)) for desiccant dehydrators because in the final subpart W rule, it was not clear how such an adjustment would be made. As such, we are clarifying the calculation methods for desiccant dehydrators that vent to a flare or vapor recovery device.

4. Well Venting for Liquids Unloading

The EPA is proposing to revise the calculation and reporting requirements for well venting from liquids unloading to allow for annualizing venting data for facilities that calculate emissions using a recording flow meter (Calculation Method 1). This proposed amendment would address reporter concerns and simplify reporting. Some reporters have expressed difficulty in collecting well venting data using a recording flow meter for the exact period of January 1 to December 31, because they contend that it would require them to be physically present at each recording flow meter on December 31. The EPA is proposing to revise Calculation Method 1 (40 CFR 98.233(f)(1)) such that reporters may use an annualized value to determine the cumulative amount of time of venting (''T_p'' in Equation W–7A and W–7B) if data are not available for the specific time period January 1 to December 31. We are specifying that if an annualized value is used, the monitoring period must begin before February 1 and must not end before December 1 of the reporting year, and that a minimum of 300 consecutive days must be used by reporters to determine the annualized vent time. The EPA is also proposing that the date of the end of one monitoring period must be the start of the next monitoring period for the next reporting year, and that all days must be monitored and all venting accounted for. We are proposing that if a reporter uses a monitoring period other than a full calendar year for any well, they must report the percentage of wells for which a monitoring period other than a full calendar year is used. Although the proposed change increases flexibility, the calculation still must be conducted in much the same way that is currently required. Therefore, the EPA does not anticipate that this proposed change will significantly affect reporting burden.

We are proposing to change Calculation Method 1 at 40 CFR 98.233(f)(1) to separate the calculation and reporting of emissions from wells that have plunger lifts and wells that do not have plunger lifts. This separation would allow the EPA and the public to more easily disaggregate emission data and activity data for wells that have plunger lifts and wells that do not have plunger lifts. We are proposing a clarification to Calculation Method 2 in 40 CFR 98.233(f)(2) to clarify that this method is used for wells without plunger lifts.

In a harmonizing change, the EPA is proposing to revise the reporting requirement for reporters using Calculation Method 1, under 40 CFR 98.236 such that reporters would be required to report the cumulative amount of time of venting for each group of wells during the year. Calculation Method 1 uses the cumulative amount of time of venting and not the number of venting events, to calculate emissions; therefore, this revision would align the reporting requirement with the calculation method. We are proposing harmonizing changes to 40 CFR 98.236 to separate the reporting of emissions from wells with and without plunger lifts when Calculation Method 1 is used.

We are also proposing to amend the definition of the term ''SPp'' in Equation W–8 (40 CFR 98.233(f)(2)) to clarify 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. This amendment would improve the consistency of the calculation method used to determine casing pressure across reporters.

We are also proposing to revise 40 CFR 98.236 to require that facilities using Calculation Methods 1, 2, and 3 report a separate count of wells with plunger lifts and wells without plunger lifts, and to report annual emissions separately from each of those sources, respectively. We are also proposing to amend 40 CFR 98.236 to require the reporting of the cumulative number of unloadings from wells with plunger lifts and unloadings from wells without plunger lifts, the average flow rate of the measured well venting for wells with and without plunger lifts, and the internal casing or tubing diameters and pressures for wells with and without plunger lifts, as applicable. These proposed revisions break out the existing count and emissions reporting requirements to more clearly specify the sources of emissions at facilities. For further information on well venting for liquids unloading, see the Technical Support Document (TSD) ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512.

5. Gas Well Completions And Workovers

The EPA is proposing to amend 40 CFR 98.238 to add definitions for ''reduced emissions completion'' and ''reduced emissions workover''. Currently, reduced emissions completions and reduced emission workovers are mentioned in the relevant calculation method as equipment that separates natural gas from the backflow and sends this natural gas to a flow-line. However, there are currently no defined terms for reduced emissions completions and reduced emissions workovers. The EPA notes that since the time that subpart W was promulgated, the EPA promulgated new source performance standards for the oil and natural gas sector under 40 CFR Part 60, subpart OOOO, that requires the use of a reduced emissions completion in specified circumstances. The EPA proposes to add a definition for ''reduced emissions completion'' to subpart W that would be consistent with the description of that term in the new source performance standard rulemaking (see 76 FR 52757–8). Specifically, the EPA is proposing to amend 40 CFR 98.238 to define a ''reduced emissions completion'' as a well completion following fracturing where gas flowback that is otherwise vented is 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 no direct release to the atmosphere. We are proposing to amend 40 CFR 98.238 to define a ''reduced emissions workover'' as a well workover with hydraulic fracturing (i.e., refracturing) where gas flowback that is otherwise vented is 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 no direct release to the atmosphere. The EPA does not anticipate these definitional changes would impact current reporters under Part 98 because these changes are clarifying in nature and do not change any requirements of subpart W.

The EPA is also proposing to amend the definition of ''well completions'' in 40 CFR 98.6 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. This amendment is intended to avoid potential confusion concerning whether a re-fracture is a completion or workover in the context of subpart W. This change will also better align the existing definition of ''well completions'' with the new proposed definition of a ''reduced emissions completion'' by clarifying that a reduced emission completion only applies to new fractures and that re-fractures are potentially covered under the new definition of ''reduced emission workover''. The definition of ''well workover'' in 40 CFR 98.6 already refers to re-fractures, so no clarifying change is needed for that definition.

We are also proposing to revise reporting requirements for completions and workovers to differentiate between completions and workovers with different well type combinations in each sub-basin category. A well type combination is a unique combination of the following factors: Vertical or horizontal, with flaring or without flaring, and reduced emission completion/workover or not reduced emission completion/workover. Specifically, for well completions and workovers with hydraulic fracturing, we are proposing to require separate counts and separate reporting of emissions for the different well type combinations. These revisions would improve data quality for emissions from wells with hydraulic fracturing. Because the EPA is proposing to expand the well type definition for completions and workovers with hydraulic fracturing to include whether the well completions/workovers are flared or not, and whether it is a reduced or not reduced emission completion/workover, it is possible that reporters will have more than one reporting category (i.e., different well types in each sub-basin) for completions and workovers with hydraulic fracturing. Therefore, some reporters will be required to further categorize their calculated emissions from completions and workovers with hydraulic fracturing, which they did not have to do before. We anticipate that these proposed changes will increase burden to some reporters somewhat. Reporters will be required to separate and report their calculated emissions from completions and workovers without hydraulic fracturing by whether the emissions are related to completions or workovers, which they do not have to do under the current version of the rule. We anticipate that those proposed changes would only slightly increase burden to reporters.

We are also proposing revisions to Equation W–10A that would add clarity and increase the accuracy of emissions calculations for gas well completions and workovers with hydraulic fracturing. In the final subpart W rule, the measurement or calculation for determining the ratio of flowback during well completions and workovers to 30-day production rate in Equation W–10A (40 CFR 98.233(g)) begins immediately upon initiating flowback of a well. Some reporters have asserted that the flowback characteristics of a well following hydraulic fracturing do not enable measurement or calculation to begin immediately upon initiating flowback due to a lack of sufficient gas being present, and the calculation needs to be revised to account for this fact. Therefore, the EPA is proposing to modify the calculation to require the measurement of flow rate only when sufficient gas is present to enable flow rate measurement. In addition, some reporters have asserted that the accuracy of emissions calculations could be affected by the combined use of sales gas volume and approximations on flow rates for non-measured wells. To resolve this apparent issue, the time variable ''T_p'' in Equation W–10A and W–10B is being modified. Time that the gas is routed to production would no longer be included, so it would no longer be necessary to subtract the volume of gas being sent to sales. This amendment would not significantly change the reporting burden. The proposed equations are similar in complexity as the previous equations and use measurements that are of similar complexity. This proposed revision would improve data quality and provide flexibility by providing an estimation method for data that could not likely be measured accurately.

We are also proposing changes to the calculation section at 40 CFR 98.233(g) and (h) to support the separate calculation of emissions from completions and workovers that are vented, flared, or use equipment that separates natural gas from the backflow and sends this natural gas to a flow-line (e.g., reduced emissions completions or reduced emissions workovers). Reporters currently calculate emissions from all completion and workover activities, but the equations do not facilitate the classification of the activity needed for separate reporting. We are proposing to revise Equation W–13 in 40 CFR 98.233(h) to separate the calculation of emissions from workovers from the calculation of completions into two equations. This amendment will improve data quality. We are also proposing to clarify that reporters must calculate the annual volumetric natural gas emissions from each gas well venting during workovers without hydraulic fracturing using Equation W–13A and from each gas well venting from completions without hydraulic fracturing using new Equation W–13B. We do not anticipate that this proposed change would significantly increase the reporting burden, because the proposed calculations are the same as the current calculation; we only propose to break it into two steps. The proposed methodology also requires the addition of parameter ''$E_{s,p}$'' for Equation W–13B to specify the annual volumetric natural gas emissions in standard cubic feet from well completions. We are also proposing to revise 40 CFR 98.233(g)(1) to clarify the number of measurements or calculations that must be taken to estimate the average ratio of flowback rate (FRM).

We are proposing to revise 40 CFR 98.233(g)(2) to clarify that measurements from the well flowing pressure upstream of a well choke to calculate well backflow must be collected for each sub-basin and well type combination. We are also proposing to revise 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.

For further information on gas well venting during completions and workovers, see the TSD ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512.

6. Blowdown Vents

Based on questions received during implementation of the final subpart W rule and reporter concerns, the EPA is proposing to revise Equations W–14A and W–14B to include a compressibility term. Specifically, some reporters requested that the EPA allow the use of a factor to adjust for compressibility when calculating emissions from blowdown vents. The calculation method for blowdown vents included in the existing subpart W rule assumes natural gas is an ideal gas with a compressibility factor of 1, and does not include an adjustment for compressibility in the calculation. Although the EPA had previously considered including the compressibility term (76 FR 56010, September 9, 2011), the EPA ultimately did not propose including the factor, because we then concluded that including a compressibility adjustment could create a degree of uncertainty between reporters on how their reported blowdown values compared (on a volume basis). We noted at that time that although the compressibility of pure light hydrocarbon substances is well known, the compressibility of hydrocarbon mixtures is less well known and the composition of natural gas throughout the segments covered by subpart W can be variable. At that time, we determined that ideal gas law calculations were adequate for reporting purposes under Part 98.

The EPA notes that the circumstances surrounding this issue are now different because, as discussed in Section III.B.1 of this preamble, the EPA is proposing to require the use of site-specific data on gas compositions, if available. In addition, we have determined that at high pressures and low temperatures, the accuracy of the emission estimate would be improved if a compressibility factor were included in the calculation. The compressibility of methane at standard conditions is close to one. However, the compressibility of methane at low temperatures and high pressures is lower than one, which may affect the accuracy of the emission calculation if not included in that calculation. Therefore, the EPA proposes to revise Equations W–14A and W–14B in 40 CFR 98.233(i) to include the compressibility term ''Z_a''. A default compressibility term of 1 may be used at conditions where the pressure is below 5 atmospheres, and the temperature is above -10 degrees Fahrenheit, or if the compressibility factor at the actual temperature and pressure is 0.98 or greater. We are proposing harmonizing changes to Equations W–33 and W–34 in 40 CFR 98.233(t) to include the compressibility term ''Z_a'' for conversion of volumetric emissions at actual conditions to standard conditions. Because it is likely that most facilities handle gas within the proposed compressibility factor default ranges, it is unlikely that adding this compressibility factor term into the blowdown vent stack calculations will significantly increase the reporting burden.

The EPA is also proposing to simplify the reporting for blowdowns. In the final subpart W rule, reporters must calculate and record emissions for each blowdown event that is greater than or equal to 50 cubic feet of actual volume. Currently, for each piece of equipment (unique physical volume) that is blown down more than one time in a calendar year, reports are submitted for the total number of blowdowns, the emissions for each unique physical volume, and the name or ID number for the unique physical volume. For all equipment that is blown down only once during the calendar year, reports are submitted as an aggregate for all such equipment at each facility. Reports include the total number of blowdowns and the emissions from all equipment with unique physical volumes that are blown down only once. The volume of gas vented is calculated for each blowdown event using the conditions specific to the event. However, the reporting of each ''unique physical volume'' blown down more than once in a year may be an extensive list of unique equipment.

A similar reporting approach was adopted by the EPA in the November 2010 version of subpart W (75 FR 74458). There, the reporting requirement specified that emissions be reported collectively per equipment type. This approach caused some confusion because a list of equipment types was not provided. Therefore we are proposing to revise the current reporting requirements in 40 CFR 98.236(c)(7) to simplify the reporting structure to report blowdown emissions aggregated by seven categories: station piping, pipeline venting, compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns, and all other blowdowns greater than or equal to 50 cubic feet. Although facilities are no longer required to report blowdown vent stack emissions by each unique physical volume, facilities still have to calculate blowdown vent stack emissions from each unique physical volume and categorize the emissions by equipment. Therefore, the EPA has determined that this proposed change would not significantly impact burden to reporters.

The EPA is also proposing an optional calculation method for blowdown emissions for situations where a flow meter is in place to measure the emissions directly. If a blowdown vent is equipped with a flow meter, there would not be an advantage to calculating the emissions using the unique volume, temperature, and pressure conditions of the equipment instead of the directly measured flow rate. We are proposing this alternative calculation method in 40 CFR 98.233(i), along with associated reporting requirements in 40 CFR 98.236. We are also proposing additional clarifying edits for both the blowdown calculation and reporting sections of the rule. If a flow meter is in place to measure emissions, the emissions would be reported on a facility basis, and would not be aggregated by emission type per 40 CFR 98.236(i)(2). For further information on blowdown vents, see the TSD ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512.

7. Onshore Production Storage Tanks

We are proposing to revise the method for estimating emissions from occurrences of well pad gas-liquid separator liquid dump valves that are not properly operating for onshore production storage tanks. The EPA initiated this revision to address reporter concerns and to improve data quality. Specifically, reporters expressed concern with the burden associated with quantifying and recording information for all properly functioning dump valves. The proposed revisions would require the detection of an anomaly and only then require quantification. Hence only those dump valves found to not be closing properly (i.e., stuck dump valves) would have to be quantified. Specifically, the EPA is proposing to simplify Equation W–16 to calculate emissions for only periods when the dump valve is not closing properly.

The EPA is also proposing to revise the reporting section to make it clear that facilities are to separately report the emissions from onshore production storage tanks attributable to periods when dump valves are not closing properly, as opposed to emissions that occur when dump valves are closing properly. In the final subpart W rule, 40 CFR 98.236(c)(8)(iv) requires that facilities report annual total volumetric GHG emissions that resulted from dump valves that are not closing properly. However, Equation W–16 in the final subpart W rule sums the total emissions for periods when the dump valve is closing properly and periods when the dump valve is not closing properly. The EPA is clarifying 40 CFR 98.236 to specify that facilities that use Equation W–16 should report only emissions that result from dump valves that are not closing properly. Note that emissions from atmospheric tanks that are not a result of dump valves not closing properly would continue to be reported in this proposed revision outside of Equation W–16. There is no significant additional burden to facilities, because reporters already use these data elements in Equation W–16: separate tank and dump valve emissions already need to be calculated separately, but would now also be reported separately. This revision would eliminate potential confusion for reporters, clarify recordkeeping requirements, and improve the ability to quantify emissions from stuck dump valves. For further information on emissions from improperly functioning dump valves, see the TSD ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512. These proposed revisions would improve the quality of data collected.

8. Associated Gas Venting and Flaring

The EPA is proposing to add a term to Equation W–18 (40 CFR 98.233(m)(3)) 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. These amendments improve data quality by eliminating duplicate reporting. Emissions are currently calculated based on the gas-to-oil ratio (GOR) and volume of oil produced during the flaring period. The GOR is based on total gas from the well, which means all the gas would currently be reported as flared even though a portion of the gas goes to a sales line. The proposed revision to Equation W–18 subtracts the volume of associated gas sent to sales from the annual volumetric natural gas emissions from associated gas venting. The EPA has also included in the equation a term ($ERE_{p,q}$) for emissions reported under other sources included in this subpart (i.e., tank venting) to avoid double counting of these emissions. The EPA also proposes updating the definition of the term $GOR_{p,q}$ and the emission result $E_{a,n}$ in Equation W–18 to specify that the gas to oil ratio and the result of the calculation are calculated at standard conditions rather than actual conditions. Because the GOR is measured in standard cubic feet, this change would harmonize the equation terms and the result of the emission calculation equation would be at standard conditions. Although the proposed calculation method modifies the current equation to include two new terms, these terms are already being calculated elsewhere and/or can be estimated. Therefore, the EPA does not anticipate that this proposed change will significantly affect the reporting burden.

The EPA is also proposing to add a definition for the term ''Associated gas venting or flaring'' to clarify what is included in this source. The EPA is proposing to define ''Associated gas venting or flaring'' as ''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 definition does not include venting or flaring resulting from activities that are reported elsewhere, including tank venting, well completions, and well workovers.'' The proposed definition allows for greater consistency with the changes made to the calculation method. This is a clarifying proposed change that improves data quality and should not significantly affect the burden to current reporters. For further information on emissions from associated gas, see the TSD ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems;

Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512.

9. Flare Stack Emissions

The EPA is proposing to amend the calculation method for emissions from a flare stack to simplify the calculation to standard conditions and to account for gas that is sent to an unlit flare. Specifically, we are proposing to revise Equation W–19 and combine Equations W–20, and W–21. The EPA also proposes to revise the equations such that the emissions of CH_4 and CO_2 are calculated in standard conditions. We propose to remove paragraph 40 CFR 98.233(n)(11), which specifies estimating emissions for the volume of gas flared under actual conditions. We also propose to add the terms ''Z_U'' and ''Z_L'' to Equation W–19 and the terms ''Z_U'' and ''Z_L'' to Equation W–20 to account for the fraction of gas sent to an unlit flare and the fraction of gas sent to a burning flare. The fraction of feed gas sent to an unlit flare would be determined by using engineering estimates and process knowledge. The proposed changes simplify and clarify the calculation requirements and would improve the accuracy of the collected data by accounting for the fraction of emissions that are not combusted when sent to an unlit flare.

The EPA is also proposing a revision to the onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export equipment industry segments to clarify that emissions from any flares in these segments must be reported using the calculation method for emissions from a flare stack. This clarifying revision is consistent with the treatment of flares in other parts of subpart W and is necessary to calculate emissions for compressors routed to flares under the proposed compressor calculation requirement modifications. We anticipate that this proposed change may slightly increase burden for select reporters and will not significantly affect burden for most reporters; however, this clarifying revision is consistent with the treatment of flares in other parts of subpart W and is necessary to calculate emissions for compressors routed to flares under the proposed compressor calculation requirement modifications.

10. Centrifugal and Reciprocating Compressors

Some reporters have contended that the current monitoring requirements for compressor venting are overly burdensome and present safety and operational process concerns. These reporters asserted that it is not practical to require a measurement from each individual compressor for groups of compressors that are routed to a common vent manifold (or flare header), because this would require the entire group of compressors that are connected to the common manifold (or flare header) to be shutdown, blown down, and purged in order to safely install meters (or ports for temporary meters) and enable individual measurements. The reporters stated that it is extremely rare that entire groups of compressors are shutdown at the same time. In the November 2010 response to public comments on the subpart W final rule (Docket ID No. EPA–HQ–OAR–2009–0923), the EPA noted that commenters requested that the EPA allow direct measurements of common manifolded vent lines on compressors. At least one commenter stated that if continuous measurement of manifolded vent lines and aggregate annual emissions reporting were allowed as an option for measuring compressors, they would be able to safely collect and report to the EPA continuously measured data. The EPA did not include this option in the 2010 final subpart W rule because it was not clear whether measurements at a common vent outlet could be used to correctly characterize annual emissions from individual compressors.

In today's action, we are proposing changes to the centrifugal and reciprocating compressor calculation sections (see 40 CFR 98.233(o) and (p)) in order to address reporter concerns related to measuring centrifugal and reciprocating compressor emissions that are routed to a common vent manifold (or flare header). For those compressors, the EPA is proposing an option where reporters would take at least three measurements per year and report the average of the measurements. These measurements would need to be taken before emissions are comingled with other non-compressor emission sources. This option would address reporter's safety concerns for facilities that need to shut down equipment to install individual meters and maintain accurate characterization of annual emissions from compressors at the facility. Annual volumetric emissions would be determined for each manifolded group of compressors combined for all operating conditions (mode-source combinations). Reporters would still be required to report activity data for any individually measured sources (i.e., non-manifolded sources) at the compressor level. Activity data reported would include information about the individual compressors included in the manifolded vent. This proposed measurement option would allow the EPA to correctly characterize and analyze GHG emissions from all compressors at individual facilities in the petroleum and natural gas systems source category while potentially reducing burden to the industry. Although reporting elements include new activity data, reporters would no longer be required to sample manifolded compressor sources individually, thus decreasing overall burden and providing flexibility. For example, if a reporter operates seven compressors that have their blowdown vent stacks manifolded, the reporter would no longer have to conduct seven measurements every year (one for each blowdown vent stack) as required by the current rule. Instead, for this example, the reporter would be required to only conduct a measurement three times per year on the common vent stack that is associated with the manifolded group of seven compressor sources, which would decrease burden for the reporter compared to the seven measurements currently required.

The EPA considered requiring only one or two measurements per year for these manifolded sources (as opposed to the EPA proposal above for the average of three measurements). The EPA concluded that the annual process variability for these sources was high enough to warrant more than one or two measurements per year. Please see the TSD ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512, for more background and information on the options considered. In addition to seeking comment on our proposed option, the EPA is specifically seeking comment on the two other options that were considered and other derivations of these options (i.e., four measurements per year instead of three). Comments should include justification why the specific option receiving comment does not negatively impact safety, is technical and economically feasible, does not impose undue burden on reporters, and how the option is sufficiently accurate given the annual process variability for these sources.

We are also proposing to include four definitions in 40 CFR 98.238 to support the addition of the calculation method for manifolded vents. We are proposing a definition for ''compressor'' to mean ''any type of vent or valve (i.e., wet seal, blowdown valve, isolation valve, or rod packing) on a centrifugal or reciprocating compressor.'' We are proposing a definition for ''compressor mode'' to mean ''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.'' We are proposing a definition for ''manifolded compressor source'' to mean ''a compressor source that is manifolded to a common vent that routes gas from multiple compressors.'' We are also proposing a definition of ''manifolded group of compressor sources'' to mean ''a collection of any combination of compressor sources that are manifolded to a common vent.''

In addition, for compressors that are routed to an operational flare, we are proposing to allow operators to calculate and report emissions with other flare emissions (in lieu of estimating compressor emissions based on knowledge of the total flare emissions and the portion of those flare emissions that can be attributed to compressors). This proposed change addresses reporter concerns, provides flexibility, and potentially decreases burden without affecting data quality. Although operators would still be required to 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 (p)(1)), reporting emissions from compressors (that are routed to an operational flare) with other flare emissions would reduce burden, because reporters would not be required to sample compressors individually or be required to portion flare emissions attributed to compressors.

It was brought to the EPA's attention that the 3-year cycle requirement for measuring compressors in the not-operating-depressurized-mode could present a compliance challenge for some facilities, because not every facility schedules routine shutdowns for maintenance within 3 years. The EPA did not intend for reporters to perform an unscheduled shutdown of a facility for the sole purpose of taking a measurement of the compressor in the not-operating-depressurized-mode. Therefore, we are proposing to revise the requirement to measure each compressor in the not-operating-depressurized-mode at least once in any 3 consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If there is no scheduled shutdown within three consecutive calendar years, the EPA proposes that a measurement must be made at the next scheduled depressurized compressor shutdown (for reciprocating compressors, this measurement can be taken during the next scheduled shutdown when the compressor rod packing is replaced). By allowing the measurement to be taken at these specified scheduled shutdowns, operators would not have to plan a shutdown of their equipment to take a measurement of their compressor in the not-operating-depressurized-mode. This proposed amendment addresses reporters' concerns and potentially decreases burden without affecting data quality. Even though the ''not-operating-depressurized-mode'' is measured only at scheduled shutdowns (which might be every 3 years or greater), the reporter is still required to conduct an annual measurement in whatever mode the compressor is found. Therefore, the frequency in measurements is unchanged. The EPA also considered modifying the existing requirement to measure each compressor in the not-operating-depressurized-mode at least once every 3 years to correspond to a longer term, such as every 5 years. However, such an extension might not resolve the issue for all reporters. The EPA is specifically seeking comment on our proposed option as well as the additional option that was considered.

The EPA is also clarifying that for reporters that elect to conduct as found leak 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. Although this option may make it easier for some reporters to keep track of their calculated reporter emission factors, all reporters are still required to calculate reporter emission factors if they use the as found leak measurement option. Therefore, the EPA does not anticipate that this clarifying edit will significantly affect the reporting burden.

We are also proposing to restructure and revise the centrifugal and reciprocating compressor sections (see 40 CFR 98.233(o) and 40 CFR 98.233(p)) in order to improve clarity for reporters. Because the restructuring was extensive, entirely new text appears for 40 CFR 98.233(o) and 40 CFR 98.233(p). Although the proposed restructuring changes would not significantly change any of the requirements or burden, the proposed restructuring and revisions would clarify current requirements that are vague or confusing. For example, we are proposing to retain the current equations for determining emissions from each compressor's measured mode-source combination and unmeasured mode-source combination; however, we are proposing language that would explain when to use the equation(s). We are also proposing revisions to improve consistency between the centrifugal and reciprocating compressor sections (see 40 CFR 98.233(o) and 40 CFR 98.233(p)). For example, we are proposing to revise the equation variables to bring consistency between the two sections. It is our view that the restructuring and clarification revisions that we are proposing in this action for the centrifugal and reciprocating compressor sections would improve readability and usability for both industry and government regulators. For further information on measuring emissions from compressors, see the TSD ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512.

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

For natural gas distribution, the final subpart W rule requires reporters to calculate a facility emission factor for a meter/regulator run per component type at above grade metering-regulating (M–R) stations. The calculation of the emission factor using Equation W–32 in 40 CFR 98.233(r) based on the results of equipment leak surveys that are required under 40 CFR 98.233(q) at above grade transmission-distribution (T–D) stations and the subsequent annual emissions calculated for those stations using Equations W–30B. Reporters have pointed out that the nomenclature and inter-related calculations between 40 CFR 98.233(q) and (r) has caused confusion. Therefore, the EPA is proposing to revise the calculation requirements for natural gas distribution facilities and associated terminology in 40 CFR 98.233(q) and (r). Specifically, the EPA is proposing to place the facility meter/regulator run emission factor calculation in 40 CFR 98.233(q) instead of 40 CFR 98.233(r) and clarify 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 on a meter/regulator run component basis. Facilities calculate annual emissions from above grade transmission-distribution transfer stations 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 leaker emission factors for 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 summed for all component types in Equation W–31 to develop the annual facility meter/regulator run emission factors for CO_2 and CH_4. Those facility emission factors must be recalculated annually as additional equipment leak survey data becomes available from above grade transmission-distribution transfer stations. To calculate annual emissions from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations, 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). 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. These proposed revisions will alleviate the current confusion with the calculation and reporting requirements for natural gas distribution facilities while capturing the same emissions sources from this industry segment and maintaining the same level of data accuracy. Data are generally reported at a less detailed level, but there is no change in emissions coverage.

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

The EPA is proposing to clarify that emissions and volume of fuel combusted must be reported for all compressor driven internal combustion units in 40 CFR 98.236. The EPA is proposing to revise this reporting requirement to be consistent with the emission estimation methods in 40 CFR 98.233(z)(4) that specify the exemption from reporting emissions for internal combustion units with a rated heat input capacity less than or equal to 1 MMBtu/hr (130 horsepower) does not apply to internal fuel combustion sources that are compressor drivers.

C. Proposed Revisions to Missing Data Provisions

We are proposing to revise 40 CFR 98.235 to clarify the procedures for estimating missing data. We are proposing to increase the specificity regarding how to use, treat, and report missing data for each calculation specified in 40 CFR 98.233.These proposed revisions would increase clarity for reporters and improve the accuracy of the data reported by ensuring that the data substituted for missing values is limited in use, and, where necessary, well-documented and quality-assured or based on the best available estimates. To address newly acquired wells, the EPA is also proposing missing data procedures specific to facilities that are newly subject to subpart W and to existing onshore petroleum and natural gas production facilities that acquire wells that were not subject to subpart W prior to the acquisition. In these specific cases, the EPA is proposing to allow best engineering estimates for any parameter that cannot be reasonably measured or obtained according to the requirements in subpart W for up to six months from the first date of subpart W applicability. Where facilities acquired additional wells, only data and calculations associated with those newly acquired wells would fall within this proposed provision. This proposed revision provides flexibility for newly acquired facilities or wells. Missing data procedures were previously not allowed for many areas of subpart W; however, with the proposed removal of BAMM, the missing data procedures provide clarity for reporters who may have unintentionally missed required data.

D. Proposed Amendments to Best Available Monitoring Methods

In order to provide facilities with time to adjust to the requirements of the rule, subpart W has provisions allowing the optional use of best available monitoring methods (BAMM) for unique or unusual circumstances. Where a facility uses BAMM, it is required to follow emission calculations specified by the EPA, but is allowed to use alternative methods for determining inputs to calculate emissions. Inputs are the values used by facilities to calculate equation outputs. Examples of BAMM include: Monitoring methods used by the facility that do not meet the specifications of subpart W, supplier data, engineering calculations, and other company records. Facilities are required to receive approval from the EPA prior to using BAMM and these facilities are required to specify in their GHG annual reports when BAMM is used for an emission source. The EPA has previously noted that the Agency intended to ''approve the use of BAMM beyond 2011 only in cases that are unique or unusual'' (76 FR 59538). Furthermore, the EPA limited the approvals of BAMM to one reporting year in keeping with the intent to allow use of BAMM as a transitional provision until facilities come into compliance with the final rule. While the EPA occasionally uses BAMM for targeted, short-term monitoring flexibilities (i.e., provision for reporters who become subject to Part 98 from the recent GWP changes to subpart A to have automatic BAMM for the first three months of reporting), no industry-specific subpart within Part 98 continues to use the BAMM flexibility except subpart W.

In this action, the EPA is proposing to remove all provisions in 40 CFR 98.234(f) for BAMM. We are also proposing to remove and reserve 40 CFR 98.234(g), which is a provision specific to the 2011 and 2012 reporting years. The removal of BAMM will improve data quality by requiring consistent reporting for each segment in subpart W. We are proposing these amendments because we expect facilities would be able to comply with the monitoring and QA/QC methods required under subpart W after this proposed rule is finalized and effective. Reporters with issues that were unidentified at the time of the final rule will, by January 1, 2015, have had adequate time to resolve these issues. It has been the EPA's intent throughout implementation of subpart W that BAMM be available as a limited, transitional program to serve as a bridge to full compliance with the rule for cases where reporters faced reasonable impediments to compliance. The EPA never intended to extend BAMM requirements indefinitely. The proposed amendments are therefore in keeping with the EPA's stated intent to transition to reporting without BAMM. We also believe, based on several years of experience with the industry and these reporting requirements, that facilities have successfully transitioned so that they either no longer need to use BAMM or will not need to use BAMM if these proposed revisions are finalized.

In a review of BAMM request submittals for the 2014 reporting year, 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 proposed revisions would also resolve the need for BAMM for certain facilities for which the final subpart W monitoring requirements were technically infeasible. For example, the most common concerns raised in BAMM requests associated with technical infeasibility included concerns related to having to shut down a facility to install access ports to conduct compressor measurements. As discussed in Section II.B.10 of this preamble, we are making revisions that allow the testing of a common vent and that clarify 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.

In light of the extended time period in which the EPA has granted BAMM to allow facilities to come into compliance with subpart W requirements, the revisions that the EPA is proposing to make to the final rule, and the fact that all other industry-specific subparts in Part 98 no longer have continual BAMM, we expect that facilities would be in compliance with the monitoring and QA/QC methods required under subpart W for the 2015 calendar year.

The EPA requests comment and strong technical evidence for site-specific unique or unusual circumstances that would require the use of BAMM after January 1, 2015. These comments should include the details of how and why the special circumstances exist, why the data collection methods in subpart W (including those in this proposal) are not feasible, the data that could not be monitored in order to comply with subpart W, and how specifically the data could otherwise be collected. For further information on BAMM, see the TSD ''Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2011–0512.

III. Proposed Confidentiality Determinations

A. Overview and Background

In this proposed rule we are proposing confidentiality determinations for new and subtantially revised reporting data elements in the proposed amendments, with certain exceptions as discussed in more detail below. These new and substantially revised data elements would result from the proposed corrections, clarifying, and other amendments that are described in Section II of this preamble, which would also result in substantial changes to the data elements that are reported. We are also proposing to revise the confidentiality determination for one existing data element that is not being amended, as discussed in Section III.B of this preamble. The final confidentiality determinations the EPA has previously made for the remainder of the subpart W data elements are unaffected by the proposed amendments and continue to apply. For information on confidentiality determinations for the GHGRP and subpart W data elements, see: 75 FR 39094, July 7, 2010; 76 FR 30782, May 26, 2011; 77 FR 48072, August 13, 2012; and 78 FR 55994, September 11, 2013. These proposed confidentiality determinations would be finalized after considering public comment. The EPA plans to finalize these determinations at the same time the proposed rule amendments described in this action are finalized.

B. Approach to Proposed CBI Determinations for New or Revised Subpart W Data Elements

For the proposed new and substantially revised data elements, except for the specific data elements separately addressed below, we are applying the same approach as previously used for making confidentiality determinations for data elements reported under the GHGRP. In the ''Confidentiality Determinations for Data Required Under the Mandatory Greenhouse Gas Reporting Rule and Amendments to Special Rules Governing Certain Information Obtained Under the Clean Air Act'' (hereinafter referred to as ''2011 Final CBI Rule'') (76 FR 30782, May 26, 2011), the EPA grouped Part 98 data elements into 22 data categories (11 direct emitter data categories and 11 supplier data categories) with each of the 22 data categories containing data elements that are similar in type or characteristics. The EPA then made categorical confidentiality determinations for eight direct emitter data categories and eight supplier data categories and applied the categorical confidentiality determination to all data elements assigned to the category. Of these data categories with categorical determinations, the EPA determined that four direct emitter data categories are comprised of those data elements that meet the definition of ''emissions data,'' as defined at 40 CFR 2.301(a), and that, therefore, are not entitled to confidential treatment under section 114(c) of the CAA.[1] The EPA determined that the other four direct emitter data categories and the eight supplier data categories do not meet the definition of ''emission data.'' For these data categories that are determined not to be emission data, the EPA determined categorically that data in three direct emitter data categories and five supplier data categories are eligible for confidential treatment as CBI, and that the data in one direct emitter data category and three supplier data categories are ineligible for confidential treatment as CBI. For two direct emitter data categories, ''Unit/Process 'Static' Characteristics that Are Not Inputs to Emission Equations'' and ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' and three supplier data categories, ''GHGs Reported,'' ''Production/Throughput Quantities and Composition,'' and ''Unit/Process Operating Characteristics,'' the EPA determined in the 2011 Final CBI Rule that the data elements assigned to those categories are not emission data, but the EPA did not make categorical CBI determinations for them. Rather, the EPA made CBI determinations for each individual data element included in those categories on a case-by-case basis taking into consideration the criteria in 40 CFR 2.208. No final confidentiality determination was made for the inputs to emission equation data category (a direct emitter data category).

For this rulemaking, we are proposing to assign 243 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. Note that subpart W is a direct emitter source category, thus, no data are assigned to any supplier data categories.

For data elements the EPA has assigned in this proposed action to a direct emitter category with a categorical determination, the EPA is proposing that the categorical determination for the category be applied to the proposed new or revised data element. For the proposed categorical assignment of the data elements in these eight categories with categorical determinations, see Memorandum Data Category Assignments and Confidentiality Determinations for all Data Elements (excluding inputs to emission equations) in the Proposed ''Technical Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2011–0512.

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 are proposing confidentiality determinations on a case-by-case basis taking into

[1] Direct emitter data categories that meet the definition of ''emission data'' in 40 CFR 2.301(a) are Facility and Unit Identifier Information, Emissions, Calculation Methodology and Methodological Tier, Data Elements Reported for Periods of Missing Data that are not Inputs to Emission Equations, and Inputs to Emission Equations.

consideration the criteria in 40 CFR 2.208, consistent with the approach used for data elements previously assigned to these two data categories. For the proposed categorical assignment of these data elements, see Memorandum Data Category Assignments and Confidentiality Determinations for all Data Elements (excluding inputs to emission equations) in the Proposed ''Technical Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2011–0512. For the results of our case-by-case evaluation of these data elements, see Sections III.C and III.D of this preamble.

For the reasons stated below, we are proposing individual confidentiality deteminations for 11 new or substantially revised data elements without making a data category assignment. In the 2011 Final CBI rule, although the EPA grouped similar data into categories and made categorical confidentiality determinations for a number of data categories, the EPA also recognized that similar data elements may not always have the same confidentiality status, in which case the EPA made individual instead of categorical determinations for the data elements within such data categories.[2] Similarly, while the 11 proposed new or substantially revised data elements are similar in type or certain characteristics to data elements previously assigned to the ''Production/Throughput Data Not Used as Input'' and ''Raw Materials Consumed that are Not Inputs to Emission Equations'' data categories, we do not believe that they share the same confidentiality status as the non-subpart W data elements already assigned to those two data categories, which the EPA has determined categorically to be CBI based on the data elements assigned to those categories at the time of the 2011 Final CBI Rule. As discussed in more detail below, our review showed that these 11 subpart W production and throughput-related data elements fail to qualify for confidential treatment. Therefore, we do not believe that the categorical determinations for the ''Production/Throughput Data Not Used as Input'' and ''Raw Materials Consumed that are Not Inputs to Emission Equations'' data categories are appropriate for these 11 data elements; accordingly, these data elements should not be assigned to these data categories. Not assigning these 11 data elements to these two data categories would also leave unaffected the existing categorical determinations for these data categories, which remain valid and applicable to the data elements assigned to those data categories. For the reasons stated above, we are proposing individual confidentiality determinations for these 11 data elements without making categorical assignment.

Our proposed individual determinations follow the same two-step evaluation process as set forth in the 2011 Final CBI Rule and subsequent confidentiality determinations for Part 98 data. Specifically, we first determined whether the data element meets the definition of emission data in 40 CFR 2.301(a). Data elements that meet the definition of emission data are required to be released under section 114 of the Clean Air Act. For data elements found to not meet the definition of emission data, we evaluated whether a data element meets the criteria in 40 CFR 2.208 for confidential treatment. In particular, we focus on: (1) Whether the data are already public; and (2) whether ''. . . disclosure of the information is likely to cause substantial harm to the business's competitive position.'' For the results of our case-by-case evaluation of these proposed new subpart W data elements, see Section III.D of this preamble.

We are also proposing to revise the confidentiality determinations for one existing subpart W data element. Our review of the 11 proposed data elements discussed above led us to re-examine our previous determination for this data element, which is similar in type or characteristics to the 11 proposed data elements for which the EPA is choosing to make case-by-case determinations. This one data element is the only subpart W data element currently assigned to ''Production/Throughput Data Not Used as Input'' data category. As discussed in more detail in Section III.D of this preamble, our review showed that this data element fails to qualify for confidential treatment. For the same reasons set forth above for not proposing categorical assignments for the 11 data elements, we are proposing to remove this data element's current category assignment, as well as the application of the categorical CBI determination to this data element. Instead, we are re-proposing a confidentiality determination based on the two-step process discussed above for the proposed 11 new data elements. For the results of our case-by-case evaluation of the proposed subpart W data elements, see Section III.D of this preamble.

We are proposing to assign 40 new or substantially revised data elements used to calculate GHG emissions in subpart W to the ''Input to Emission Equation'' data category. To date, the EPA has not made confidentiality determinations for any data element, including any subpart W data element, assigned to the ''Inputs to Emission Equation'' data category. We are therefore not proposing confidentiality determinations for the 40 proposed new or substantially revised inputs to emission equations data elements. However, due to concerns expressed by reporters with the potential release of inputs to emission equations, we previously established a process for evaluating ''inputs to emission equation'' data elements to identify potential disclosure concerns and actions to address such concerns if appropriate.[3] The EPA has used this process to evaluate inputs to emission equations, including the subpart W data elements that are already assigned to the inputs to emission equations data category.[4] We performed a similar evaluation for the 40 proposed new and substantially revised subpart W inputs to emission equations and did not identify any potential disclosure concerns. Accordingly, the proposal would require reporting of these data elements by March 31, 2016, which is the reporting deadline for the 2015 reporting year. For the list of new and revised subpart W inputs to emission equations and the results of our evaluation, see memorandum titled ''Review of Public Availability and Harm Evaluation for Proposed New Inputs to Emission Equations in the Proposed 'Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems' '' in Docket ID No. EPA–HQ–OAR–2011–0512.

The proposed amendments include revisions a number of subpart W data reporting elements for which confidentiality determinations were previously finalized in the August 13, 2012 ''Final Confidentiality Determinations for Regulations Under the Mandatory Reporting of Greenhouse Gases Rule'' (77 FR 48072). The proposed revisions relative to some of

[2] In the 2011 Final CBI rule, several data categories include both CBI and non-CBI data elements. See 76 FR 30786.

[3] See the ''Change to the Reporting Date for Certain Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule'' (hereinafter referred to as the ''Final Deferral Notice'') (76 FR 53057, August 25, 2011) and the accompanying memorandum entitled ''Process for Evaluating and Potentially Amending Part 98 Inputs to Emission Equations'' (Docket ID EPA–HQ–OAR–2010–0929).

[4] See the memoranda titled ''Summary of Data Collected to Support Determination of Public Availability of Inputs to Emission Equations for which Reporting was Deferred to March 31, 2015'' and ''Evaluation of Competitive Harm from Disclosure of Inputs to Equations Data Elements Deferred to March 31, 2015.'' (Docket ID EPA–HQ–OAR–2010–0929).

these data reporting elements would not require different or additional data to be reported under these data elements. The proposed revisions include a reorganization of the reporting requirements so that the data elements more close align with the calculation methodologies. This reorganization of the reporting section would result in changes to many of the rule citations for data elements. In addition to re-structuring the reporting section, the EPA has proposed other minor revisions designed to clarify the existing reporting requirements. For example, some of the proposed changes would clarify the source type (e.g., natural gas pneumatic device venting, acid gas removal vents, etc.) and industry segment that is required to report the data element. The proposed revisions also include corrections of typographical and other clerical errors. These corrections would not change the data to be reported. Although the proposed revisions would separate the requirements into a larger number of discrete reporting elements and would clarify and correct typographical errors, they would not change the underlying data elements to be reported for many data elements. Therefore, the confidentiality determinations finalized in the August 13, 2012 rule continue to apply. We are therefore not proposing revisions to the existing confidentially determinations for the data reporting elements that either would not require different or additional data to be reported under the proposed revisions or the proposed revisions would not change the underlying data elements to be reported. For a summary of the proposed reporting requirements for subpart W that incorporate these changes to data organization and descriptions, see the memo, ''Proposed Revisions to the Subpart W Reporting Requirements'' in Docket ID No. EPA–HQ–OAR–2011–0512.

C. Proposed Confidentiality Determinations 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'' Data Categories

The EPA is proposing to assign 101 proposed new or substantially revised data elements for subpart W to the ''Unit/Process 'Operating' Characteristics That Are Not Inputs to Emission Equations'' data category or the ''Unit/Process 'Static' Characteristics That Are Not Inputs to Emission Equations'' data category, because the proposed new or substantially revised data elements share the same characteristics as the other data elements previously assigned to the category. We are proposing confidentiality determinations for these proposed new or substantially revised data elements based on the approach set forth in the 2011 Final CBI Rule for data elements assigned to these two data categories. In that rule, the EPA determined categorically that data elements assigned to these two data categories do not meet the definition of emission data in 40 CFR 2.301(a); the EPA then made individual, instead of categorical, confidentiality determinations for these data elements.

As with all other data elements assigned to these two categories, the proposed new or substantially revised data elements do not meet the definition of emissions data in 40 CFR 2.301(a). The EPA then considered the confidentiality criteria at 40 CFR 2.208 in making our proposed confidentiality determinations. Specifically, we focused on whether the data are already publicly available from other sources and, if not, whether disclosure of the data is likely to cause substantial harm to the business' competitive position. Table 2 of this preamble lists the data elements the EPA proposes to assign to the ''Unit/Process 'Operating' Characteristics That Are Not Inputs to Emission Equations'' and ''Unit/Process 'Static' Characteristics That Are Not Inputs to Emission Equations'' data categories, the proposed confidentiality determination for each data element, and our rationale for each determination.

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE ''UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS'' AND ''UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS'' DATA CATEGORIES

Citation	Data element	Proposed confidentiality determination and rationale
''Unit/Process 'Operating' Characteristics That Are Not Inputs to Emission Equations'' Data Category		
98.236(d)(1)(iv)	Whether any CO_2 emissions are recovered and transferred outside the facility.	This proposed data element would be reported by onshore petroleum and natural gas production facilities and by onshore natural gas processing plants. This data element indicates that a facility is operating an acid gas removal unit and indicates how the facility handles the CO_2 emissions it generates. Acid gas removal units are used to remove carbon dioxide and hydrogen sulfide from raw natural gas streams and are commonly found at gas processing facilities. These units are listed in a facility's construction and operating permits, which are publicly available. Because this information is routinely available through required permits, we propose these data elements be designated as ''not CBI.''

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
98.236(e)(1)(xvii)	For each absorbent dehydrator, whether any dehydrator emissions are vented to the atmosphere without being routed to a flare or regenerator firebox.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities and by onshore natural gas processing plants. These data elements indicate that a facility is equipped with dehydration units, the number of dehydrators used, the design of dehydrator used (glycol or desiccant), and how emissions from dehydration units are handled by the facility. Dehydration units are used to remove water from natural gas streams. Most natural gas processing facilities are equipped with these units and because they are a source of hazardous air pollutants, these units are subject to rigorous emissions control requirements (e.g., 40 CFR part 63, subpart HH). Dehydration units and their associated control devices are listed in a facility's construction and operating permits, which are publicly available. For this reason, we propose these data elements be designated as "not CBI" for both onshore production and natural gas processing plants.
98.236(e)(2)(i)	For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscfd, the total number of dehydrators at the facility.	
98.236(e)(2)(ii)	For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscfd, the total number of dehydrators venting to a vapor recovery device.	
98.236(e)(2)(iii)	For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscfd, the number of dehydrators venting to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes.	
98.236(e)(2)(iv)	For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscfd, whether any glycol dehydrator emissions are vented to a flare or regenerator firebox/fire tubes.	
98.236(e)(2)(iv)(A)	For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscfd and vented to a flare or regenerator firebox, the total number of dehydrators.	
98.236(e)(3)(i)	For dehydrators that use desiccant, the total number of dehydrators at the facility.	
98.236(e)(3)(i)	For dehydrators that use desiccant, whether any dehydrator emissions are vented to a vapor recovery device.	
98.236(e)(3)(i)	For dehydrators that use desiccant, the total number of dehydrators venting to a vapor recovery device.	
98.236(e)(3)(i)	For dehydrators that use desiccant, whether any dehydrator emissions are vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes, and the control device type.	
98.236(e)(3)(i)	For dehydrators that use desiccant, whether any dehydrator emissions are vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes.	
98.236(e)(3)(i)	For dehydrators that use desiccant, the number of dehydrators venting to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes.	
98.236(e)(3)(i)	For dehydrators that use desiccant, whether any glycol dehydrator emissions are vented to a flare or regenerator firebox/fire tubes.	
98.236(e)(3)(i)	For dehydrators that use desiccant and vent to a flare or regenerator firebox, the total number of dehydrators.	

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
98.236(f)	Liquids unloading. You must indicate whether well venting for liquids unloading occurs at your facility.	These proposed data element would be reported by onshore petroleum and natural gas production facilities. Liquid unloading is conducted in mature gas wells that have an accumulation of liquids which impede the steady flow of natural gas. This is a common occurrence in reservoirs where the pressure is depleted and liquids enter the well bore. The fact that liquids unloading occurs and the number of unloading wells with and without plungers vented to the atmosphere indicate that the wells in a basin are older and may indicate changes in production rates. However, the age and production rates for wells are information that can be derived from or are already available to the public through state oil and gas commissions. Hence, this information is routinely publicly available, so we propose these data elements be designated as "not CBI."
98.236(f)(1)(iv)	For each Sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 (reported separately for wells with plunger lifts and wells without plunger lifts), the count of wells vented to the atmosphere for this grouping.	
98.236(g)	Whether the facility had any gas well completions or workovers with hydraulic fracturing in the calendar year.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities and provide information on whether the facility conducted any well completions or workovers during the reporting year, and for those facilities that had well completions and/or workovers, the number of completions and workovers that were completed. Information on the number of completions and workovers performed by an oil and gas operator in a given year and the age and production rates for wells can be derived from or is available publicly on state oil and gas commission Web sites. Because disclosure of these data elements would not be likely to cause substantial competitive harm, we propose these data elements be designated as "not CBI."
98.236(g)(3)	For each completion or workover and well type combination, the total number of completions or workovers.	
98.236(h)(1)	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.	This proposed data element would be reported by onshore petroleum and natural gas production facilities and provides information on whether the facility conducted any well completions or workovers during the reporting year and whether the emissions were flared. Information on completions and workovers performed in a given year and the age and production rates for wells can be derived from or is available publicly on state oil and gas commission Web sites and from the Energy Information Administration (EIA). Whether the emissions from well completions and workovers are sent to a flare provides only information about how the emissions are handled by the facility, which is not considered to be sensitive information by the industry. Because disclosure of these data elements would not be likely to cause substantial competitive harm, we propose these data elements be designated as "not CBI."
98.236(h)(1)(ii)	For each sub-basin with gas well completions without hydraulic fracturing and without flaring, the number of completions that vented gas to the atmosphere.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities and provide information on the number of completions where gas is vented to the atmosphere and the number of completions where the gas is vented to a flare. The number of completions that vent gas directly to the atmosphere and the number of completions that send the gas to a flare provides only information about the number of well completions that were performed in a sub-basin during a reporting year and how the emissions are handled by the facility. The number of completions performed each year is available publicly on state oil and gas commission Web sites and from the EIA. Thus, disclosure of these data elements would not be likely to cause substantial competitive harm and we propose these data elements be designated as "not CBI."
98.236(h)(2)(ii)	For each sub-basin with gas well completions without hydraulic fracturing with flaring, the number of well completions that flared gas.	

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
98.236(h)(1)(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 "Vp" as used in Equation W–13B).	This proposed data element would be reported by onshore petroleum and natural gas production facilities. This data element potentially provides information about the productivity of wells where hydraulic fracturing is not conducted and the emissions are not flared. Because production data for individual production wells are publicly available, the average daily production for all wells in a basin presents no information that is not already publicly available. Because disclosure of this data element would not be likely to cause substantial competitive harm, we propose this data element be designated as "not CBI."
98.236(h)(2)(iii)	Total number of hours that gas vented to a flare during backflow for all completions in the sub-basin category (sum of all "Tp" for completions that vented to a flare as used in Equation W–13B).	This proposed data element would be reported by onshore petroleum and natural gas production facilities and potentially provides information on the time spent on well completions. Information specific to exploratory wells is generally considered proprietary information by the industry. However, by reporting this data as the total for all completed wells in a sub-basin category, data for individual wells would not be disclosed because of the large number of wells per sub-basin category. Because disclosure of this data element would not be likely to cause substantial competitive harm, we propose this data element be designated as "not CBI."
98.236(h)(2)(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 "Vp" from Equation W–13B).	This proposed data element would be reported by onshore petroleum and natural gas production facilities. This data element potentially provides information about the productivity of wells where hydraulic fracturing is not conducted and the emissions are flared. Because production data for individual production wells are publicly available, the average daily production for all wells in a basin presents no information that is not already publicly available. Because disclosure of this data element would not be likely to cause substantial competitive harm, we propose this data element be designated as "not CBI."
98.236(i)(1)(i)	Total number of blowdowns in the calendar year for the equipment type (sum equation variable "N" from Equation W–14A or Equation W–14B of this subpart for all unique physical volumes for the equipment type).	This proposed data element would be reported by the onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, and LNG import and export facilities. Blowdowns occur when equipment is taken out of service, either to be placed on standby or for maintenance purposes, and the natural gas in the equipment is typically released to the atmosphere. This practice may occur as part of a routine scheduled maintenance or as the result of an un-planned event (e.g., equipment breakdown). Although blowdown events may be associated with periods of reduced production or throughput, natural gas processing plants and LNG import/export facilities typically have backup units that can be used to avoid production shutdowns. Hence, the number of blowdown events that occur during a reporting year does not indicate a plant was shut down and would not provide any potentially sensitive information on the impact of such events on a facility's production or throughput. Hence, the disclosure of the number of blowdowns occurring during a reporting year is not likely to cause substantial competitive harm. For this reason, we propose that this data element be designated "not CBI" when reported by onshore natural gas processing plants and LNG import/export facilities.

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
		These proposed data elements would also be reported by the natural gas transmission compression sector. Companies operating in this sector are subject to regulatory oversight by the Federal Energy Regulatory Commission (FERC), state utility commissions, and other federal agencies because they operate in an industry that is inherently uncompetitive. FERC controls pricing, sets rules for business practices, has the power to impose conditions on mergers and acquisitions, and has the sole responsibility for authorizing the location, construction and operations of companies operating in this sector. The rate charged for transporting gas is regulated. Hence the tightly regulated natural gas transmission sector is inherently less competitive than other industries. Because disclosure of the number of blowdowns occurring during a reporting year would not be likely to cause substantive competitive harm, we propose this data element be designated as "not CBI" when reported by the natural gas transmission sector.
98.236(j)	You must indicate whether your facility sends produced oil to atmospheric tanks.	This proposed data element would be reported by onshore petroleum and natural gas production facilities and indicates only that a facility is equipped with atmospheric storage tanks. Atmospheric storage tanks are used to store hydrocarbon liquids from separators or production wells. Atmospheric tanks are a typical part of onshore production facilities and are listed in each facility's construction and operating permits, which have to be reissued when modifications are made to the facility. Hence, disclosure of this data element would not be likely to cause substantial competitive harm and we propose that this data element be designated as "not CBI."
98.236(j)	If any of the atmospheric tanks are observed to have malfunctioning dump valves, indicate that dump valves were malfunctioning.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities and provide information on malfunctioning of dump valves on gas-liquid separators. Separators are used to separate hydrocarbons into liquid and gas phases and are typically connected to atmospheric storage tanks where the hydrocarbon liquids are stored. Dump valves on separators periodically release liquids from the separator. 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. Therefore, this information would not be likely to cause substantial competitive harm to reporters. For this reason, we are proposing these data elements be designated as "not CBI."
98.236(j)(3)(ii)	If any of the gas-liquid separator liquid dump valves did not close properly during the reporting year, the total time, in hours, the dump valves on gas-liquid separators did not close properly ("Tn" in equation W–16).	
98.236(k)(1)(iii)	For each transmission storage tank vent stack, indicate whether scrubber dump valve leakage is occurring for the underground storage vent.	These proposed data elements would be reported by the onshore natural gas transmission compression sector. Companies operating in this sector are subject to regulatory oversight by FERC, state utility commissions, and other federal agencies because they operate in an industry that is inherently uncompetitive. FERC controls pricing, sets rules for business practices, has the power to impose conditions on mergers and acquisitions, and has the sole responsibility for authorizing the location, construction and operations of companies operating in this sector. The rate charged for transporting gas is regulated. Hence the natural gas transmission sector is inherently less competitive than other industries and there is little incentive to build additional pipelines and compressor stations within the same corridors as existing transmission lines. Because disclosure of these data elements would not be likely to cause substantive competitive harm, we propose these data elements be designated as "not CBI."
98.236(k)(1)(iv)	For each transmission storage tank vent stack, indicate if there is a flare attached to the vent stack.	

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
98.236(l)(1)(iv)	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.	This proposed data element would be reported by onshore petroleum and natural gas production facilities. These data elements provide information on the oil flow and gas production rates of wells. Oil and gas production data for individual wells are publicly available. Because production data for individual production wells are publicly available, the average of all wells tested presents no information that is not already publicly available. Because disclosure of these data elements would not be likely to cause substantial competitive harm, we propose these data elements be designated as "not CBI."
98.236(l)(2)(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.	
98.236(l)(3)(iii)	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.	
98.236(l)(4)(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.	
98.236(m)	You must indicate whether any associated gas was vented or flared during the reporting year.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities and indicate whether associated gas is flared or vented directly to the atmosphere. Information on how emissions are handled does not provide any insight into the operation of the emission source. Therefore, disclosure of these data elements would be unlikely to cause competitive harm. For this reason, we are proposing these data elements be designated as "not CBI."
98.236(m)(2)	For each sub-basin, indicate whether any associated gas was vented without flaring.	
98.236(m)(3)	For each sub-basin, indicate whether any associated gas was flared.	
98.236(m)(5)	For each sub-basin, the volume of oil produced during time periods in which associated gas was vented or flared (barrels).	These proposed data elements would be reported by onshore petroleum and natural gas production facilities and provide production related information during periods when associated gas is vented or flared. Associated gas is vented or flared when it is not being captured for sales. Oil and gas production data for individual production wells are publicly available, By reporting this data as total for all production wells in a sub-basin category, no data for individual wells is disclosed that is not already publicly available. Because disclosure of these data elements would not be likely to cause substantial competitive harm, we propose they be designated as "not CBI."
98.236(m)(6)	For each sub-basin, the total volume of associated gas sent to sales during time periods in which associated gas was vented or flared (scf).	
98.236(o)(1)(xvi)	Date of last maintenance shutdown that the compressor was depressurized.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities, onshore natural gas processing plants, LNG import/export terminals, natural gas transmission compression, underground natural gas storage facilities, and LNG storage facilities. These data elements provide information about the operation and maintenance of centrifugal compressors. Centrifugal compressors are used to move gas at high pressure through pipelines and are standard equipment found at all types of natural gas facilities. Facilities typically have backup compressors to allow operations to continue without interruption during periods of maintenance and repair. Hence, the percentage of time a compressor was operational and the date of last maintenance shutdown would be not likely to cause substantial competitive harm to any type of natural gas facility. For these reasons, we propose these data elements be designated as "not CBI."
98.236(o)(2)(viii)	If the emission vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational.	

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
98.236(p)(1)(xvi)	Date of last maintenance shutdown for rod packing replacement.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities, onshore natural gas processing plants, LNG import/export terminals, natural gas transmission compression, underground natural gas storage facilities, and LNG storage facilities. These data elements provide information about the operation and maintenance of reciprocating compressors. Reciprocating compressors are used to move gas at high pressure through pipelines and are standard equipment found at all types of natural gas facilities. Facilities typically have backup compressors to allow operations to continue without interruption during periods of compressor maintenance and repair. Hence, the percentage of time a compressor is operational and date of last maintenance shutdown would be not likely to cause substantial competitive harm to any type of natural gas facility. For these reasons, we propose these data elements be designated as "not CBI."
98.236(p)(2)(viii)	If the emission vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational.	
98.236(q)(2)(iii)	Average time the surveyed components were found leaking and operational, in hours (average of $T_{p,z}$ in Equation W–30 of this subpart).	This proposed data element would provide information on the amount of time operational components were found to be leaking. This information would provide little insight into maintenance practices at a facility because it would not identify the cause of the leaks or the nature and cost of repairs. Therefore, this information would not be likely to cause substantial competitive harm to reporters. For this reason, we are proposing the average time operational components were found leaking be designated as "not CBI."
98.236(q)(3)(ii)	Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in the calendar year.	These proposed data elements would be reported by natural gas distribution facilities. Natural gas distribution companies are subject to regulatory oversight by state utility commissions because they operate in an industry that is inherently not competitive. The state utility commission controls pricing, sets rules for business practices, has the power to impose conditions on mergers and acquisitions, and has the sole responsibility for authorizing the location, construction and operations of companies operating in this sector. Because disclosure of these data elements would not be likely to cause substantive competitive harm, we propose these data elements be designated as "not CBI" when reported by natural gas distributors.
98.236(q)(3)(iii)	Average time that meter/regulator runs surveyed in the calendar year were operational, in hours (average of $T_{w,y}$ in Equation W–31 of this subpart, for the current calendar year).	
98.236(q)(3)(v)	Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in current leak survey cycle.	
98.236(q)(3)(vi)	Average time that meter/regulator runs surveyed in the current leak survey cycle were operational, in hours.	
98.236(w)	Whether CO_2 enhanced oil recovery (EOR) injection was used at the facility.	This proposed data element would be reported by onshore petroleum and natural gas production facilities. This data element indicates whether EOR is performed. However, underground injection of CO_2 is regulated under 40 CFR parts 124, 144 and 146. Facilities that inject CO_2 underground are required to have an Underground Injection Control (UIC) permit, which is a public document issued by the EPA or by states that have primary enforcement authority for permitting injection wells. Since this information is already available through other public documents, we propose this data be designated as "not CBI."
98.236(w)	You must indicate whether any EOR injection pump blowdowns occurred during the year.	This proposed data element would be reported by the onshore petroleum and natural gas production facilities using EOR. Blowdowns are a typical operation undertaken by EOR operators and occur when equipment is taken out of service either to be placed on standby or for maintenance purposes. This practice may occur as part of a routine scheduled maintenance or be the result of an un-planned event (e.g., equipment breakdown). Although blowdown events may be associated with periods of reduced production, facilities typically have backup pumps that can be used to avoid production shutdowns. Hence, the disclosure of the number of blowdowns occurring during a reporting year is not likely to cause substantial competitive harm. For this reason, we propose that this data element be designated "not CBI."

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
98.236(x)	Whether hydrocarbon liquids were produced through EOR operations.	This proposed data element would be reported by onshore petroleum and natural gas production facilities using EOR and provides production related information about EOR operations. However, production data for wells is available to the public through state oil and gas commissions. Since this information is already available through other public documents, we propose this data be designated as "not CBI."
98.236(z)(2)(i)	The type of combustion unit	This data element would be reported by onshore petroleum and gas production facilities and natural gas distribution. This data element would provide information on the types of combustion units. Information on the types of combustion units located at a facility is often available in a facility's construction and operating permits. For these reasons, we consider information on the types of combustion units in production and distribution facilities would not be likely to cause substantive competitive harm and propose this data element be designated as "not CBI" for both industry sectors.
98.236(z)(2)(ii)	Type of fuel combusted	This data element would be reported by onshore petroleum and gas production facilities and natural gas distribution. This data element would provide information on the types of fuel burned. However, facilities in both these sectors generally burn fuels that are readily available to them as part of their operations. Information on the types of fuels burned by a facility is often available in a facility's construction and operating permits. For these reasons, we consider information on the types of fuels burned by production and distribution facilities would not be likely to cause substantive competitive harm and propose this data element be designated as "not CBI" for both industry sectors.
98.236(aa)(1)(ii)(I)	For each sub-basin category, the average mole fraction CH_4 in produced gas.	This proposed data element would be reported by onshore petroleum and natural gas production facilities. The typical composition of produced gas is available through the Gas Technology Institute and the Department of Energy, Gas Information System (GASIS) Database.[5] Both of these sources are made available to the public. Since these data are publicly available we are proposing these data elements be designated as "not CBI."
98.236(aa)(1)(ii)(J)	For each sub-basin category, the average mole fraction CO_2 in produced gas.	
98.236(aa)(4)(i)	The quantity of gas transported through the compressor station in the calendar year, in thousand standard cubic feet.	These proposed data elements would be reported by the onshore natural gas transmission compression sector. Companies operating in this sector are subject to regulatory oversight by FERC, state utility commissions, and other federal agencies because they operate in an industry that is inherently uncompetitive. FERC controls pricing, sets rules for business practices, has the power to impose conditions on mergers and acquisitions, and has the sole responsibility for authorizing the location, construction and operations of companies operating in this sector. The rate charged for transporting gas is regulated. Hence the natural gas transmission sector is inherently less competitive than other industries and there is little incentive to build additional pipelines and compressor stations within the same corridors as existing transmission lines. Because disclosure of pipeline pressures and the quantity of gas transported through the compressor would not be likely to cause substantive competitive harm, we propose these data elements be designated as "not CBI."
98.236(aa)(4)(iv)	The average upstream pipeline pressure in pounds per square inch gauge.	
98.236(aa)(4)(v)	The average downstream pipeline pressure in pounds per square inch gauge.	

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Citation	Data element	Proposed confidentiality determination and rationale
98.236(aa)(5)(i)	The quantity of gas injected into storage in the calendar year, in thousand standard cubic feet.	These proposed data elements would be reported by underground natural gas storage facilities. Underground storage facilities are closely associated with and are part of the utilities' integrated distribution systems. Some are owned by natural gas distribution companies. Distribution companies are regulated by state commissions, because they operate in an industry that is inherently not competitive. Underground storage facilities are constrained by geographical and geological requirements. These facilities must be located in areas where appropriate geologic conditions exist for gas storage, while also located near regions of the country where gas usage fluctuates during the year. Typically, gas is injected into underground storage during the summer months, when consumer demand is low, and withdrawn during the winter months, when demand peaks. These factors provide significant barriers to new companies moving into the underground storage sector or existing companies increasing their market share. Because disclosure of these proposed new data elements would not be likely to cause substantive competitive harm to underground storage facilities, we propose these data elements be designated as "not CBI."
98.236(aa)(5)(ii)	The quantity of gas withdrawn from storage in the calendar year, in thousand standard cubic feet.	
98.236(aa)(6)	For LNG import equipment, the quantity of LNG imported in the calendar year, in thousand standard cubic feet.	Quantities of LNG imported to the U.S. together with the name of the importer are published by EIA in quarterly reports. Because disclosure of this proposed new data element would not be likely to cause substantive competitive harm, we propose this data element be designated as "not CBI."
98.236(aa)(7)	For LNG export equipment, the quantity of LNG exported in the calendar year, in thousand standard cubic feet.	Quantities of natural gas exported from the U.S. are published by EIA in quarterly reports. Because disclosure of this proposed new data element would not be likely to cause substantive competitive harm, we propose this data element be designated as "not CBI."
98.236(aa)(8)(i)	The quantity of LNG added into storage in the calendar year, in thousand standard cubic feet.	These proposed data elements would be reported by LNG storage facilities. Most LNG storage facilities are owned by distributors whose operations are regulated by FERC and state commissions, because they operate in an industry that is inherently not competitive. FERC controls pricing, sets rules for business practices, has the power to impose conditions on mergers and acquisitions, and has the sole responsibility for authorizing the location, construction and operations of companies operating in this sector. Because disclosure of these proposed new data elements would not be likely to cause substantive competitive harm, we propose these data elements be designated as "not CBI."
98.236(aa)(8)(ii)	The quantity of LNG withdrawn from storage in the calendar year, in thousand standard cubic feet.	
98.236(aa)(9)(i)	The quantity of natural gas received at all custody transfer stations in the calendar year in thousand standard cubic feet.	Natural gas distribution companies are subject to regulatory oversight by state utility commissions, because they operate in an industry that is inherently not competitive. Many of these data elements are also reported to EIA on a monthly basis (e.g., natural gas withdrawn from storage, natural gas stored, gas received at city gate). EIA publishes the data on their Web site on an annual basis. Because disclosure of these proposed new data elements would not be likely to cause substantive competitive harm, we propose these data elements be designated as "not CBI."
98.236(aa)(9)(ii)	The quantity of natural gas withdrawn from in-system storage in the calendar year in thousand cubic feet.	
98.236(aa)(9)(iii)	The quantity of natural gas added to in-system storage in the calendar year in thousand cubic feet.	
98.236(aa)(9)(iv)	The quantity of natural gas delivered to end users in thousand cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for	
98.236(aa)(9)(v)	The quantity of natural gas transferred to third parties such as other LDCs or pipelines in thousand cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.	
98.236(aa)(9)(vi)	The quantity of natural gas consumed by the LDC for operational purposes in thousand cubic feet.	
98.236(aa)(9)(vii)	The estimated quantity of gas stolen in the calendar year in thousand cubic feet.	

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
"Unit/Process 'Static' Characteristics That Are Not Inputs to Emission Equations" Data Category		
98.236(o)(1)(iv) operating mode (v) not operating mode.	For non-manifolded compressors, whether the compressor was measured in the operating-mode or the not-operating-depressurized–mode.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities, onshore natural gas processing plants, LNG import/export terminals, natural gas transmission compression, underground natural gas storage facilities, and LNG storage facilities. These data elements indicate whether a facility has centrifugal compressors, how emissions from each unit are handled, and specific information about the design and age of each centrifugal compressor. Centrifugal compressors are used to move gas at high pressure through pipelines and are standard equipment found at all types of natural gas facilities. Centrifugal compressors are also listed in each facility's construction and operating permits, which must be updated and reissued when modifications are made. Hence, the fact that a facility has a centrifugal compressor, its age and design, and emissions handling reveals no sensitive information that would be likely to cause substantial competitive harm to any type of natural gas facility. For these reasons, we propose these data elements be designated as "not CBI."
98.236(o)(1)(vii)	Indicate whether any compressor sources are routed to a flare.	
98.236(o)(1)(viii)	Indicate whether any compressor sources have vapor recovery.	
98.236(o)(1)(ix)	Indicate whether emissions from any compressor sources are captured for fuel use or are routed to a thermal oxidizer.	
98.236(o)(1)(x)	Indicate whether the compressor has blind flanges installed.	
98.236(o)(1)(xi)	Indicate whether the compressor has wet or dry seals.	
98.236(o)(1)(xiii)	Compressor power rating (hp).	
98.236(o)(1)(xiv)	Year compressor was installed.	
98.236(o)(1)(xv)	Compressor model name and description.	
98.236(p)(1)(viii)	Indicate whether any compressor sources are part of a manifolded group of compressor sources.	These proposed data elements would be reported by onshore petroleum and natural gas production facilities, onshore natural gas processing plants, LNG import/export terminals, natural gas transmission compression, underground natural gas storage facilities, and LNG storage facilities. These data elements indicate whether a facility has reciprocating compressors, how emissions from each unit are handled, and specific information about the design and age of each reciprocating compressor. Reciprocating compressors are used to move gas at high pressure through pipelines and are standard equipment found at all types of natural gas facilities. Reciprocating compressors are also listed in each facility's construction and operating permit, which must be updated and reissued when modifications are made. Because disclosure of these data elements would be not likely to cause substantial competitive harm to any type of natural gas facility, we propose these data elements be designated as "not CBI."
98.236(p)(1)(ix)	Indicate whether any compressor sources are routed to a flare.	
98.236(p)(1)(x)	Indicate whether any compressor sources have vapor recovery.	
98.236(p)(1)(xi)	Indicate whether emissions from any compressor sources are captured for fuel use or are routed to a thermal oxidizer.	
98.236(p)(1)(xii)	Indicate whether the compressor has blind flanges installed.	
98.236(p)(1)(xiii)	Compressor power rating (hp).	
98.236(p)(1)(xiv)	Year compressor was installed.	
98.236(p)(1)(xv)	Compressor model name and description.	
98.236(z)(1)(ii)	The total number of combustion units	This data element would be reported by onshore petroleum and gas production facilities and natural gas distribution. This data element provides information on the number of internal and external combustion units located at onshore petroleum and natural gas production facilities. However, this information would not be likely to cause substantial competitive harm if released to the public, since internal and external combustion units are typical parts of an onshore petroleum and natural gas production facility and the total number of such units is not considered to be competitively sensitive information by this industry sector. Because disclosure of the number of combustion units would not be likely to cause substantive competitive harm to this sector, we propose this data element be designated as "not CBI" when reported by onshore petroleum and natural gas production facilities. Natural gas distribution companies are subject to regulatory oversight by state utility commissions, because they operate in an industry that is inherently not competitive. Because disclosure of the number combustion units would not be likely to cause substantive competitive harm, we propose this data element be designated as "not CBI" when reported by natural gas distributors.

TABLE 2—PROPOSED NEW DATA ELEMENTS ASSIGNED TO THE "UNIT/PROCESS 'OPERATING' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" AND "UNIT/PROCESS 'STATIC' CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS" DATA CATEGORIES—Continued

Citation	Data element	Proposed confidentiality determination and rationale
98.236(aa)(1)(ii)(C)	For each sub-basin category, the formation type.	The formation type refers to the following types of formations: Oil, high permeability gas, shale gas, coal seam, or other tight gas reservoir rock. The location of these formations is general information that is publicly available from EIA. Because disclosure of the formation would not be likely to cause substantive competitive harm, we propose this data element be designated as "not CBI."
98.236(aa)(1)(ii)(D)	For each sub-basin category, the number of producing wells at the end of the calendar year.	We are proposing that each of these proposed new data elements be assigned to the Unit/Process Static Characteristics That Are Not Inputs to Emission Equations" because each data element provides descriptive information about units at the facility and does not meet the definition of emission data. We propose that each new data element be designated as "not CBI" because detailed information regarding wells is available from state databases and permits. Because disclosure of the formation would not be likely to cause substantive competitive harm, we propose this data element be designated as "not CBI."
98.236(aa)(1)(ii)(E)	For each sub-basin category, the number of producing wells acquired during the calendar year.	
98.236(aa)(1)(ii)(F)	For each sub-basin category, the number of producing wells divested during the calendar year.	
98.236(aa)(1)(ii)(G)	For each sub-basin category, the number of wells completed during the calendar year.	
98.236(aa)(1)(ii)(H)	For each sub-basin category, the number of wells taken out of production during the calendar year.	
98.236(aa)(3)(vii)	Whether the onshore natural gas processing facility fractionates natural gas liquids (NGLs).	Whether a natural gas processing facility fractionates NGLs is information that is readily available from other public sources, such as the LPG Almanac (updated annually) and other trade journals. For this reason, disclosure of this information would not be likely to cause substantial competitive harm and we propose that this data element be designated as "not CBI."
98.236(aa)(4)(ii)	Number of compressors	These data elements would be reported by the onshore natural gas transmission compression sector. Companies operating in this sector are subject to regulatory oversight by FERC, state utility commissions, and other federal agencies because they operate in an industry that is inherently uncompetitive. FERC controls pricing, sets rules for business practices, has the power to impose conditions on mergers and acquisitions, and has the sole responsibility for authorizing the location, construction and operations of companies operating in this sector. Because disclosure of the number and power rating for compressors would not be likely to cause substantive competitive harm, we propose these data elements be designated as "not CBI."
98.236(aa)(4)(iii)	The total compressor power rating for all compressors combined, in horsepower.	
98.236(aa)(5)(iii)	The total storage capacity for underground natural gas storage facilities.	Companies operating underground gas storage facilities are required to report their storage capacity to the EIA by company on a monthly basis. EIA publishes the data on their Web site on an annual basis. Because disclosure of underground storage capacity would not be likely to cause substantial competitive harm, we propose these data elements be designated as "not CBI."
98.236(aa)(8)(iii)	The total LNG storage capacity in the calendar year, in thousand standard cubic feet.	Most LNG storage facilities are regulated by FERC and state commissions, because they operate in an industry that is inherently not competitive. FERC controls pricing, sets rules for business practices, has the power to impose conditions on mergers and acquisitions, and has the sole responsibility for authorizing the location, construction and operations of companies operating in this sector. Because disclosure of LNG storage capacity would not be likely to cause substantial competitive harm, we propose these data elements be designated as "not CBI."

D. Other Proposed or Re-Proposed Case-by-Case Confidentiality Determinations for Subpart W

The proposed revision includes 11 new or substantially revised data elements relative to production and/or throughput data from subpart W facilities from the onshore petroleum and natural gas production, offshore petroleum and natural gas production, and onshore natural gas processing industry sectors. Although these data elements are similar in certain types or characteristics to the data elements in "Production/Throughput Data that are Not Inputs to Emissions Equations" or "Raw Materials Consumed that are Not Inputs to Emissions Equations" data categories, for the reasons provided above in Section III.B of this preamble, we are not proposing to assign these data elements to a data category. Instead, we are proceeding to make individual confidentiality determinations for these data elements. As further explained in Section III.B of this preamble, we are also proposing to remove one existing data element, 40 CFR 98.236(j)(2)(i)(A), from ''Production/Throughput Data Not Used as Input,'' thereby removing the application of the categorical confidentiality determination for this data category to this data element. We are re-proposing the confidentiality determination for this data element. Table 3 of this preamble lists the 11 new or substantially revised data elements and one existing data element and provides the rationale and proposed confidentiality determination for each data element.

As described above in Section III.B of this preamble, our proposed determinations for these data elements were based on a two-step process in which we first evaluated whether the data element met the definition of emission data. This first step in the evaluation is important because emission data are not eligible for confidential treatment pursuant to section 114(c) of the CAA, which precludes emissions data from being considered confidential and requires that such data be made available to the public. The term ''emission data'' is defined in 40 CFR 2.301(a).

We propose to determine that none of these 12 data elements are emission data under 40 CFR 2.301(a)(2)(i), because they do not provide any information characterizing actual GHG emissions or descriptive information about the location or nature of the emissions source. However, we note that this determination is made strictly in the context of the GHGRP and may not apply to other regulatory programs.

In the second step, we evaluate whether the data element is entitled to confidentiality treatment, based on the criteria for confidential treatment specified in 40 CFR 2.208. In particular, the EPA focused on the following two factors: (1) Whether the data was already publicly available; and (2) whether '' . . . disclosure of the information is likely to cause significant harm to the business' competitive position.'' *See* 40 CFR 2.208(e)(1). For each of these 12 data elements, we determined whether the information is already available in the public domain.

For those data elements for which no published data could be found, we evaluated whether the publication would be likely to cause competitive harm. Many of the new data elements proposed to be reported by the onshore oil and gas production sector would be reported at an aggregated-level (i.e., sub-basin level) that would mask any underlying information for individual production wells. These data elements involve reporting aggregated data covering all individual wells, exploratory wells, and production equipment in a sub-basin, rather than information specific to an individual well or other production unit. Reporting at a sub-basin level is at a large enough scale that disclosure of the collected data would not reveal any proprietary information, such as the sensitive operational information or the cost to do business. Because the proposed new data elements would also be collected at a sub-basin level, they would not disclose production data for individual wells, reveal information about individual exploratory wells, or provide insight into production costs. Therefore, we propose that the new production data proposed to be reported by the onshore oil and gas production sector be designated as non-CBI because its disclosure would not be likely to cause competitive harm.

For offshore oil and gas production, the EPA is proposing that the quantity of gas produced for sales, quantity of oil produced for sales, and quantity of condensate produced for sales be reported. These data elements do not provide any competitively sensitive information on the costs of doing business. We note that similar data on throughputs for individual platforms are published annually by the Bureau of Ocean Energy Management. Therefore, we propose that these new production data proposed to be reported by offshore oil and gas platforms be designated as non-CBI because its disclosure would not be likely to cause competitive harm.

For natural gas processing, the EPA is proposing that the total quantity of NGLs (bulk and fractionated) received at and leaving the processing plant be reported on an annual basis. Because the reported value would be the annual sum of bulk and fractionated NGLs received and the annual sum of bulk and fractionated NGLs leaving the plant, the data collected would provide very limited information on facility operations and would not disclose any detailed information about the facility's day-to-day operations, such as the amount, contents, and price of each shipment of bulk material received, the amount, contents, and price of each shipment of NGL product received, the amount of bulk materials fractionated and costs of fractionation, or the type and amounts of each individual NGL product produced. Because these data are to be reported at an aggregated level, these proposed two new data elements would not provide insight on operating costs, or other highly sensitive aspects of operation the disclosure of which would be likely to cause competitive harm. Therefore, we propose that the total quantity of NGLs (bulk and fractionated) received at and leaving the natural gas processing plant be designated as not CBI. In addition, many facilities in this sector already voluntarily report these data to the Worldwide Gas Processing survey and the data at the plant level are published annually in the Oil and Gas Journal. Similar data are also mandatorily reported monthly to the EIA. Although the EIA aggregates the data before publishing data, the EIA also acknowledges that some statistics may be based on data from fewer than three respondents, or that are dominated by data from one or two large respondents, and in these cases, it may be possible for a the information reported by a specific respondent to be accurately estimated.

TABLE 3—PROPOSED INDIVIDUAL CONFIDENTIALITY DETERMINATION FOR 13 NEW OR SUBSTANTIALLY REVISED DATA ELEMENTS AND RE-PROPOSAL FOR ONE EXISTING DATA ELEMENTS

Citation	Data element	Proposed confidentiality determination and rationale
Onshore petroleum and natural gas production		
98.236(aa)(1)(i)(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.	We propose that each of these data elements be designated as "not CBI." The onshore petroleum production sector is a regionally concentrated sector, with wells located in fixed geological formations and a large number of operators within each formation. Information that is typically considered sensitive to this industry includes data related to production costs for developed fields and information on individual exploratory wells. Information on exploratory wells is sensitive during the time period when a new formation is being developed because lease prices are not stabilized until wells have proven production records. Once the formation has been developed and several wells have been drilled in a basin, production decisions are based on market prices and the ability to control flow from the well. The production data that will be reported at the basin or sub-basin level are already publicly available through the Department of Energy. Reporting at the basin or sub-basin level includes data aggregated to a scale large enough that it does not disclose production data for individual wells, reveal sensitive information about individual exploratory wells, or provide insight into production costs.
98.236(aa)(1)(i)(B)	The quantity of gas produced in the calendar year for sales in thousand standard cubic feet.	
98.236(aa)(1)(i)(C)	For each basin, the quantity of crude oil produced in the calendar year for sales, not including lease condensates, in barrels.	
98.236(aa)(1)(i)(D)	For each basin, the quantity of lease condensate produced in the calendar year for sales (in barrels).	
98.236(j)(2)(i)(A)	The total annual oil throughput that is sent to all atmospheric tanks in the basin, in barrels.	
Offshore petroleum and natural gas production		
98.236(aa)(2)(i)	The quantity of gas produced for sales from the offshore platform in the calendar year for sales, in thousand standard cubic feet.	We propose that each of these new data elements be designated as "not CBI" because the production throughput data are published annually on the Bureau of Ocean Energy Management's Web site.
98.236(aa)(2)(ii)	The quantity of oil produced for sales from the offshore platform in the calendar year for sales (in barrels).	
98.236(aa)(2)(iii)	The quantity of condensate produced for sales from the offshore platform in the calendar year for sales (in barrels).	
Onshore natural gas processing		
98.236(aa)(3)(i)	The quantity of produced gas received at the gas processing plant in thousand standard cubic feet.	We propose that each of these new data elements be designated as "not CBI" because the average annual flow and plant utilization rates are published quarterly on EIA's Web site and are already in the public domain.
98.236(aa)(3)(ii)	The quantity of processed (residue) gas leaving the gas processing plant in thousand standard cubic feet.	
98.236(aa)(3)(iii)	The quantity of NGLs (bulk and fractionated) received at the gas processing plant in the calendar year, in barrels.	We propose that each of these new data elements be designated as "not CBI" because they are already publicly available. Many facilities in this sector already voluntarily report these data to the Worldwide Gas Processing survey and the data at the plant level are published annually in the Oil and Gas Journal. Similar data are also mandatorily reported monthly to the EIA. Although the EIA aggregates the data before publishing data, the EIA also acknowledges that, "Disclosure limitation procedures are not applied to the statistical data published from this survey's information. Thus, there may be some statistics that are based on data from fewer than three respondents, or that are dominated by data from one or two large respondents. In these cases, it may be possible for a knowledgeable person to estimate the information reported by a specific respondent."[6]
98.236(aa)(3)(iv)	The quantity of NGLs (bulk and fractionated) leaving the gas processing plant in the calendar year, in barrels.	

The list of data elements, their data category assignments, and proposed confidentiality determinations can be found in the memorandum titled "Data Category Assignments and Confidentiality Determinations for all Data Elements (excluding inputs to emission equations) in the Proposed 'Technical Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'" in Docket ID No. EPA–HQ–OAR–2011–0512.

E. Request for Comments on Proposed Confidentiality Determinations

For the CBI component of this rulemaking, we are specifically soliciting comment on the following issues. First, we specifically seek comment on the proposed data category assignments, and application of the established categorical confidentiality determinations to data elements assigned to categories with such determinations. If a commenter believes that the EPA has improperly assigned certain new or substantially revised data elements to any of the data categories established in the 2011 Final CBI Rule, please provide specific comments identifying which of these data elements may be mis-assigned along with a detailed explanation of why you believe them to be incorrectly assigned and in which data category you believe they belong. In addition, if you believe that a data element should be assigned to one of the two direct emitter data categories that do not have a categorical confidentiality determination, please also provide specific comment along with detailed rationale and supporting information on whether such data element does or does not qualify as CBI.

We also seek comment on the proposed individual confidentiality determinations for the following data elements: 72 new or substantially revised data elements assigned to the ''Unit/Process 'Operating' Characteristics That Are Not Inputs to Emission Equations'' data category; 29 new or substantially revised data elements assigned to the ''Unit/Process 'Static' Characteristics That Are Not Inputs to Emission Equations'' category; 11 new data elements for which no data category assignment was proposed; and one existing data element for which we are proposing to remove the data category assignment and make a new confidentiality determination.

By proposing confidentiality determinations prior to data reporting through this proposal and rulemaking process, we provide reporters an opportunity to submit comments, in particular comments identifying data they consider sensitive and their rationales and supporting documentation; this opportunity is the same opportunity that is afforded to submitters of information in case-by-case confidentiality determinations made in response to individual claims for confidential treatment not made through rulemaking. It provides an opportunity to rebut the Agency's proposed determinations prior to finalization. We will evaluate the comments on our proposed determinations, including claims of confidentiality and information substantiating such claims, before finalizing the confidentiality determinations. Please note that this will be a reporter's only opportunity to substantiate a confidentiality claim for these proposed new data elements. Upon finalizing the confidentiality determinations of the data elements identified in this rule, the EPA will release or withhold these data in accordance with 40 CFR 2.301, which contains special provisions governing the treatment of Part 98 data for which confidentiality determinations have been made through rulemaking.

When submitting comments regarding the confidentiality determinations we are proposing in this action, please identify each individual data element you do or do not consider to be CBI or emission data in your comments. Please explain specifically how the public release of that particular data element would or would not cause a competitive disadvantage to a facility. Discuss how this data element may be different from or similar to data that are already publicly available. Please submit information identifying any publicly available sources of information containing the specific data elements in question. Data that are already available through other sources would likely be found not to qualify for CBI protection. In your comments, please identify the manner and location in which each specific data element you identify is publicly available, including a citation. If the data are physically published, such as in a book, industry trade publication, or federal agency publication, provide the title, volume number (if applicable), author(s), publisher, publication date, and International Standard Book Number (ISBN) or other identifier. For data published on a Web site, provide the address of the Web site and the date you last visited the Web site and identify the Web site publisher and content author.

If your concern is that competitors could use a particular data element to discern sensitive information, specifically describe the pathway by which this could occur and explain how the discerned information would negatively affect your competitive position. Describe any unique process or aspect of your facility that would be revealed if the particular data element you consider sensitive were made publicly available. If the data element you identify would cause harm only when used in combination with other publicly available data, then describe the other data, identify the public source(s) of these data, and explain how the combination of data could be used to cause competitive harm. Describe the measures currently taken to keep the data confidential. Avoid conclusory and unsubstantiated statements, or general assertions regarding potential harm. Please be as specific as possible in your comments and include all information necessary for the EPA to evaluate your comments.

IV. Impacts of the Proposed Amendments to Subpart W

The proposed amendments to subpart W are based on identified improvements in the regulatory language and revisions to calculation methods that do not significantly increase the burden of data collection and reporting, improve the accuracy of the data reported, and provide clarity. The proposed amendments do not impart significant additional burden to reporters and many reduce burden to reporters and regulators in some cases.

As discussed in Section II of this preamble, the EPA is proposing to revise the reporting elements that must be reported. Any elements that were not previously required to be reported identify the equipment to be reported for the industry segment or are inputs to an emission equation. These data elements are typically already collected by reporters. These proposed revisions would remove ambiguity for the reporter and would not increase burden significantly, since the reporting elements are already available.

As discussed in Section II.D of this preamble, the EPA is proposing to remove the best available monitoring method (BAMM) provisions in 40 CFR 98.234(f). Removing these provisions would not add to previous burden estimates for subpart W reporters; previous burden estimates were prepared based on all reporters complying with the monitoring methods in 40 CFR 98.234 without BAMM.

The additional proposed amendments to subpart W are not expected to significantly increase burden. See the memorandum, ''Assessment of Impacts of the 2014 Proposed Revisions to Subpart W'' in Docket Id. No. EPA–HQ–OAR–2011–0512 for additional information.

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 proposed amendments to subpart W. This analysis is contained in ''Assessment of Impacts of the 2014 Proposed 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 proposed 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 Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2300.15.

This action proposes to simplify the existing reporting methods in subpart W and clarify monitoring methods and data reporting requirements, and proposes confidentiality determinations for reported data elements. The EPA is proposing to restructure the reporting requirements for clarity and align them with the calculation requirements. 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. 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 estimated total projected cost and hour burden associated with reporting for subpart W are $21,964,000 and 244,000 hours, respectively. For the hour burden, the estimated average burden hours per response is 54 hours, the proposed frequency of response is once annually, and the estimated number of likely respondents is 2,885. For the cost burden to respondents or record keepers resulting from the collection of information, the estimated total capital and start-up cost component annualized over its expected useful life is $796,000 per year, the total operation and maintenance component is $1,690,000 per year, and the total labor cost is $19,478,000 per year for all of subpart W.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA–HQ–OAR–2011–0512. Submit any comments related to the ICR to the EPA and OMB. See ADDRESSES section at the beginning of this proposed rule for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503, Attention: Desk Office for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after March 10, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by April 9, 2014. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal. We continue to be interested in the potential impacts of this proposed action on the burden associated with the proposed amendments and welcome comments on issues related to such impacts.

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 proposed 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 proposes to (1) amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. After considering the economic impacts of these proposed rule amendments on small entities, I certify that this action would not have a significant economic impact on a substantial number of small entities.

The small entities directly regulated by this proposed 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 proposed amendments that do not result in a significant burden increase on subpart W reporters. In some cases, the EPA is proposing to increase flexibility in the selection of methods used for calculating GHGs, and is also proposing to revise certain methods that may result in greater conformance to current industry practices. In addition, the EPA is proposing to revise specific provisions to provide clarity on what information is being reported. These proposed revisions would not significantly increase the burden on reporters while maintaining the data quality of the information being reported to the EPA.

As part of the process of finalization of the final subpart W 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 conducted several meetings with industry associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. 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.

The EPA continues to be interested in the potential impacts of the proposed rule amendments on small entities and welcomes comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Federal agencies must also develop a plan to provide notice to small governments that might be significantly or uniquely affected by any regulatory requirements. The plan must enable officials of affected small governments to have meaningful and timely input in the development of the EPA regulatory proposals with significant federal intergovernmental mandates and must inform, educate, and advise small governments on compliance with the regulatory requirements.

This action proposes to (1) amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. This proposed rule does not contain a 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 proposed 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. The proposed amendments would not impose any new requirements that are not currently required for 40 CFR part 98, and the rule amendments would not uniquely apply to 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).

This action proposes to (1) amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. Few, if any, state or local government facilities would be affected by the provisions in this proposed 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.

In the spirit of Executive Order 13132, and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials. For a summary of the EPA's consultation with state and local organizations and representatives in developing Part 98, see Section VIII.E of the preamble to the final rule (74 FR 56371, October 30, 2009).

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. This action proposes to (1) Amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This regulation would apply directly to petroleum and natural gas facilities that emit greenhouses gases. 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 final subpart W published on November 30, 2010 (75 FR 74458).

The EPA specifically solicits additional comment on this proposed action from tribal officials.

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 proposes to (1) Amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. 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 proposes to (1) amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. 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 proposes to (1) Amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. This proposed rulemaking does not involve the use of any technical standards. No changes are being proposed that affect the test methods currently in use for subpart W. Therefore, the EPA is not considering the use of any 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.

This action proposes to (1) amend monitoring and calculation methodologies in subpart W; (2) assign subpart W data reporting elements into CBI data categories; and (3) amend a definition in subpart A. The EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. Instead, this proposed rule addresses information collection and reporting procedures.

List of Subjects in 40 CFR Part 98

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

Dated: February 20, 2014.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 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—[AMENDED]

■ 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—[AMENDED]

■ 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, maintenance and repair 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 paragraph (c)(11);
■ b. Revising paragraph (d)(1);
■ c. Revising paragraph (e)(1);
■ d. Adding paragraph (e)(6);
■ e. Revising paragraph (f)(1);
■ f. Adding paragraph (f)(4);
■ g. Revising paragraph (g)(1);
■ h. Adding paragraph (g)(4);
■ i. Revising paragraph (h)(1);
■ j. Adding paragraph (h)(5); and
■ k. 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 paragraphs (a) introductory text, (a)(1), and (a)(2);
■ b. 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 paragraph (j)(5) as paragraph (j)(3) and revising newly redesignated paragraph (j)(3);
■ g. Redesignating paragraph (j)(6) as paragraph (j)(4) and revising newly redesignated paragraph (j)(4);
■ h. Redesignating paragraph (j)(7) as paragraph (j)(5) and revising newly redesignated paragraph (j)(5);
■ i. Redesignating paragraph (j)(8) as paragraph (j)(6) and revising newly redesignated paragraph (j)(6);

■ j. Redesignating paragraph (j)(9) as paragraph (j)(7) and revising newly redesignated paragraph (j)(7);
■ k. Revising paragraph (k);
■ l. Revising paragraphs (l) introductory text, (l)(2) introductory text, and (l)(2)(ii);
■ m. Revising paragraphs (l)(3) introductory text and the parameters ''FR'' and ''D'' of Equation W–17B in paragraph (l)(3);
■ n. Revising paragraphs (l)(5) and (l)(6);
■ o. Revising paragraphs (m), (n), (o), (p), (q), and (r);
■ p. Revising paragraphs (s)(2) introductory text, (s)(2)(i), (s)(3), (s)(4), and (t) introductory text.
■ q. Revising Equation W–33 of paragraph (t)(1) and adding the parameter ''Z_a'' to Equation W–33 in paragraph (t)(1);
■ r. Revising Equation W–34 of paragraph (t)(2) and adding the parameter ''Z_a'' to Equation W–34 in paragraph (t)(2);
■ s. Revising paragraphs (u) introductory text, (u)(2)(iii), and (u)(2)(v) through (vii);
■ t. Revising paragraphs (v), (w) introductory text, (w)(1), and (w)(3) introductory text;
■ u. Revising the parameters ''$Mass_{CO2}$'', ''N'', and ''V_v'' to Equation W–37 in paragraph (w)(3);
■ v. Revising paragraphs (x) introductory text and (x)(1);
■ w. Revising the parameter ''S_{hl}'' to Equation W–38 in paragraph (x)(2);
■ x. Revising paragraph (z)(1);
■ y. Revising the parameters ''V_a'', ''Y_{CO2}'', ''Y_j'', and ''Y_{CH4}'' to Equations W–39A and W–39B in paragraph (z)(2)(iii);
■ z. Revising Equation W–40 in paragraph (z)(2)(vi) and the parameters ''$MassN_2O$'', ''Fuel'', and ''HHV'' to Equation W–40 in paragraph (z)(2)(vi); and
■ aa. 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.

* * * * *

(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.

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

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 8760 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 CH4 and CO2 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 8760 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 CO2 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

$$E_{a,CO2} = Vs * Vol_{CO2} \quad \text{(Eq. W-3)}$$

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 CO2 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.

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

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

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 CO2 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 to determine Vol_{CO2} in Equation W–3 of this section according to 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 to determine Vol_I in Equation W–4A or W–4B of this section according to 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 to determine Vol_O in Equation W–4A or W–4B of this section according to 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 at standard conditions 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 absorbent 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 (e)(1)(xi)(D) of this section.

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

(B) If the GHG mole fraction cannot be determined using paragraph (u)(2)(i) or (u)(2)(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:

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

Where:

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

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators that have an annual average 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*. Dehydrators that use desiccant 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.

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

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

p = 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 GHGi 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), (e)(2), and (e)(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) or (e)(2) of this section for absorbent dehydrators. Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(3) and (e)(4) of this section for dehydrators that use desiccant.

(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), (f)(2), or (f)(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 (f)(1)(i)(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 is 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 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 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 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 (g)(1)(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 (g)(1)(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 shall be converted 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.

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

Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

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

Where:

R = Pressure ratio.

P_1 = Pressure immediately upstream of the choke (psia).

P_2 = Pressure immediately downstream of the choke (psia).

(iii) For Equation W–10A of this section, calculate FRM_s using Equation W–12A of this section.

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

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 shall be converted 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.

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

Where:

FRM_i = Ratio of 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 (g)(2)(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 (g)(4)(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.

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

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

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 (h)(2)(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 (i)(3) of this section. 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 (i)(4) 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 type. If you elect to determine emissions according to each equipment type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraphs (i)(2)(i) through (i)(2)(iii) of this section for each equipment type. Equipment types must be grouped into the following seven categories: station piping, pipeline venting, compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns, and all other blowdowns greater than or equal to 50 cubic feet.

(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.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s Z_a} \right) - V * C \right) \qquad \text{(Eq. W-14A)}$$

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. You must retain logs documenting the 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 1 if the temperature is above −10 degrees Fahrenheit and pressure is below 5 atmospheres, or if the compressibility factor at the actual temperature and pressure is 0.98 or greater.

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

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. You must retain logs documenting the 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 1 if the temperature is above −10 degrees Fahrenheit and pressure is below 5 atmospheres, or if the compressibility factor at the actual temperature and pressure is 0.98 or greater.

(ii) Calculate the annual natural gas emissions, in cubic feet, from each equipment type by summing $E_{s,n}$, as calculated in either Equation W–14A or Equation W–14B of this subpart, for all unique physical volumes associated with the equipment type.

(iii) Calculate total annual CH_4 and CO_2 volumetric and mass emissions from each equipment type by using the annual natural gas emission value calculated in paragraph (i)(2)(ii) of this section for the 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 using unique physical volumes as specified in paragraphs (i)(1) and (i)(2) of this section, you may use a flow meter and measure blowdown vent stack emissions. If you choose to use this method, you must measure the natural gas emissions from the blowdown(s) at the facility 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 (j)(2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a wellhead separator with throughput greater than 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 paragraphs (j)(3) of this section. 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 (j)(1)(vii)(C) of this section.

* * * * *

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks, using either of the methods in paragraphs (j)(2)(i) or (j)(2)(ii) of this section. 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.

* * * * *

(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 (j)(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) 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 Calculation Methods 1, 2, or 3 in paragraphs (j)(1), (j)(2), and (j)(3) of this section (with wellhead separators) 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 Tn is 2.87 for crude oil production. Correction factor for tank emissions for time period Tn 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)(3) 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)(4) 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 (k)(1)(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 acoustic leak detection device detects a leak, then you must use one of the methods in either paragraph (k)(2)(i) or (k)(2)(ii) of this section and the requirements specified in paragraphs (k)(2)(iii) and (k)(2)(iv) of this section to quantify annual emissions.

(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 (k)(1)(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).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(iv) 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.

(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) Calculate annual emissions from storage tanks to flares as specified in paragraphs (k)(4)(i) and (k)(4)(ii) of this section.

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (k)(3) 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 (l)(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.

* * * * *

(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 (l)(2)(ii) of this section to determine GOR.

* * * * *

(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.

* * * * *

FR = Average annual flow rate in barrels of oil per day for the oil well(s) being tested.

* * * * *

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

* * * * *

(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 (l)(6)(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 (m)(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 (m)(2)(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.

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

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.

$ERE_{p,q}$ = Emissions reported elsewhere, volume of associated gas for well p in sub-basin q, in standard cubic feet, during time periods in which associated gas was vented or flared and for which emission source types of this section calculate and report emissions from the associated gas stream prior to venting or flaring of the associated gas (i.e., § 98.233(j) for onshore production storage tanks).

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 (m)(5)(ii) of this section.

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (m)(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 (n)(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 (n)(2)(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 applicable industry segment, 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.

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

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

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 (n)(7) are not required.

(9) The flare emissions determined under paragraph (n) of this section 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 (o)(5) of this section; perform calculations specified in paragraphs (o)(6) through (o)(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 (o)(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 (o)(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, the calculations specified in paragraphs (o)(1) through (o)(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 (o)(1)(ii) of this section. Manifolded compressor sources (as defined in § 98.238) must use a measurement method specified in paragraph (o)(1)(i), (o)(1)(ii), (o)(1)(iii), or (o)(1)(iv) of this section.

(i) Centrifugal compressor source as found leak measurements. Measure venting from each compressor according to either paragraph (o)(1)(i)(A) or (o)(1)(i)(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 (o)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (o)(2)(i)(A) or (o)(2)(i)(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. If a compressor has a continuously operating vapor recovery system for the wet seal degassing, then measurement of wet seal degassing is not required.

(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), (o)(2)(i)(B), or (o)(2)(i)(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.

(D) You must measure the compressor as specified in paragraph (o)(1)(i)(A) of this section at least once in any three consecutive calendar years, provided that the measurement can be taken when the compressor is in operating-mode. If three consecutive calendar years occur without measuring the compressor in operating-mode, you must measure the compressor as specified in paragraph (o)(1)(i)(A) of this section in the next calendar year that the compressor is in operating-mode for more than 2,000 hours.

(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 leak 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), (o)(1)(ii), or (o)(1)(iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting leak measurements at the common vent stack as specified in paragraph (o)(4) of this section. The leak measurements must be conducted at the frequency specified in paragraphs (o)(1)(iii)(A) through (o)(1)(iii)(C) of this section.

(A) A minimum of three leak measurements must be taken for each manifolded group of compressor sources in a calendar year.

(B) The leak measurements may be performed while the compressors are in any compressor mode.

(C) The three required leak measurements must be separated by a minimum of 60 days. If more than two leak measurements are performed, the first and last measurements in a calendar year must be separated by a minimum of 120 days.

(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), (o)(1)(ii), or (o)(1)(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 leak measurements from individual centrifugal compressor sources.* If conducting leak measurements for each compressor source, you must determine the volumetric emissions of leaks from blowdown valves and isolation valves as specified in paragraph (o)(2)(i) of this section, and the volumetric emissions of leaks 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 of leaks using one of the methods specified in paragraphs (o)(2)(i)(A) through (o)(2)(i)(C) of this section.

(A) Measure 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) Measure 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) For isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a) instead of measuring the isolation valve leakage through the blowdown vent as provided for in paragraphs (o)(2)(i)(A) or (o)(2)(i)(B) of this section.

(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 leak 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 (o)(3)(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 leak measurements from manifolded groups of centrifugal compressor sources.* If conducting leak measurements for a manifolded group of compressor sources, you must measure volumetric emissions of leaks as specified in paragraphs (o)(4)(i) and (o)(4)(ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and where emissions cannot be comingled 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 (o)(4)(ii)(C) 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).

(5) *Methods for continuous leak 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 (o)(5)(iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and where emissions cannot be comingled 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 leak 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 (o)(6)(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 (o)(1)(i)(B) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \quad \text{(Eq. W-21)}$$

Where:

$E_{s,i,m}$ = Annual volumetric GHGi (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 GHGi 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 (o)(1)(i)(B) of this section that was not measured during the reporting year.

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

Where:

$E_{s,i,m}$ = Annual volumetric GHGi (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{m,s}$ = 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 (o)(1)(i)(B) of this section. These emission factors must be 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.

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

Where:

$EF_{m,s}$ = 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.

$MT_{m,p,s}$ = 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 (MTm 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.

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

Where:

$E_{s,i,v}$ = Annual volumetric GHGi (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 GHGi 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 leak 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.

$$E_{s,i,g} = 8760 * MT_{g,avg} * GHG_{i,g} \quad \text{(Eq. W-24B)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHGi (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

$MT_{g,avg}$ = 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 GHGi 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.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \quad \text{(Eq. W-24C)}$$

Where:

$E_{s,i,g}$ = Annual volumetric GHGi (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 GHGi 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.

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

Where:

$E_{s,i}$ = Annual volumetric GHGi (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 GHGi. Use 1.2 × 107 standard cubic feet per year per compressor for CH_4 and 5.30 × 105 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(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 (o)(12)(iii) of this section.

(i) Emissions calculations under this paragraph (o) 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 (p)(5) of this section; perform calculations specified in paragraphs (p)(6) through (p)(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 (p)(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 (p)(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, the calculations specified in paragraphs (p)(1) through (p)(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 (p)(1)(ii) of this section. Manifolded compressor sources (as defined in § 98.238) must use a measurement method specified in paragraph (p)(1)(i), (p)(1)(ii), (p)(1)(iii), or (p)(1)(iv) of this section.

(i) Reciprocating compressor source as found leak measurements. Measure venting from each compressor according to either paragraph (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section at least once annually, based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement, except as specified in paragraph (p)(1)(i)(D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (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 (p)(2)(i)(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 (p)(2)(i)(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), (p)(2)(i)(B), or (p)(2)(i)(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 either prior to or during the next compressor shutdown when the replacement of the compressor rod packing occurs.

(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 leak 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), (p)(1)(ii), or (p)(1)(iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting leak measurements at the common vent stack as specified in paragraph (p)(4) of this section. The leak measurements must be conducted at the frequency specified in paragraphs (p)(1)(iii)(A) through (p)(1)(iii)(C) of this section.

(A) A minimum of three leak measurements must be taken for each manifolded group of compressor sources in a calendar year.

(B) The leak measurements may be performed while the compressors are in any compressor mode.

(C) The three required leak measurements must be separated by a minimum of 60 days. If more than three leak measurements are performed, the first and last measurements in a calendar year must be separated by a minimum of 120 days.

(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), (p)(1)(ii), or (p)(1)(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 leak measurements from individual reciprocating compressor sources.* If conducting leak measurements for each compressor source, you must determine the volumetric emissions of leaks from blowdown valves and isolation valves as specified in paragraph (p)(2)(i) of this section. You must determine the volumetric emissions of leaks from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (p)(2)(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 of leaks using one of the methods specified in paragraphs (p)(2)(i)(A) through (p)(2)(i)(C) of this section.

(A) Measure 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) Measure 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) For isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a) instead of measuring the isolation valve leakage through the blowdown vent as provided for in paragraphs (p)(2)(i)(A) or (p)(2)(i)(B) of this section.

(ii) For reciprocating rod packing equipped with an open-ended vent line on compressors in operating-mode, determine the volumetric emissions of leaks using one of the methods specified in paragraphs (p)(2)(ii)(A) and (p)(2)(ii)(B) of this section.

(A) Measure 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 § 98.234(d), respectively.

(B) Measure 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).

(iii) For reciprocating rod packing not equipped with an open-ended vent line on compressors in operating-mode, you must determine the volumetric emissions of leaks using the method specified in paragraphs (p)(2)(iii)(A) and (p)(2)(iii)(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 from the compressor crank case breather cap or other vent with a closed distance piece.

(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 leak 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 leak measurements from manifolded groups of reciprocating compressor sources.* If conducting leak measurements for a manifolded group of compressor sources, you must measure volumetric emissions of leaks as specified in paragraphs (p)(4)(i) and (p)(4)(ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and where emissions cannot be comingled 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 (p)(4)(ii)(C).

(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).

(5) *Methods for continuous leak 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 (p)(5)(iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and where emissions cannot be comingled 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 leak 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 (p)(6)(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 (p)(1)(i)(C) of this section that was measured during the reporting year.

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

Where:

$E_{s,i,m}$ = Annual volumetric GHGi (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), (p)(1)(i)(B), or (p)(1)(i)(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), (p)(1)(i)(B), and (p)(1)(i)(C) of this section that was not measured during the reporting year.

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

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.

$EF_{m,s}$ = 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 in 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), (p)(1)(i)(B), and (p)(1)(i)(C) of this section. These emission factors must be 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.

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

Where:

$EF_{m,s}$ = 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.

$MT_{m,p,s}$ = 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 (MTm 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), (p)(1)(i)(B), or (p)(1)(i)(C) of this section.

(A) Emission factors must be calculated annually for each compressor mode-source combination specified in paragraph ((p)(1)(i)(A), (p)(1)(i)(B), and (p)(1)(i)(C) of this section.

(B) You must combine emissions for blowndown vents, measured in the operating and standby-pressurized modes.

(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 leak 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.

$$E_{s,i,g} = 8760 * MT_{g,avg} * GHG_{i,g} \quad \text{(Eq. W-29B)}$$

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.

$MT_{g,avg}$ = 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 (p)(12)(iii) of this section.

(i) Emissions calculations under this paragraph (p) 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 (a)(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 Equations 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.

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

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 found 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, 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 to determine the meter/regulator run population emission factors for each GHG_i. The meter/regulator run population emission factors calculated using Equation W–31 must be used in Equation W–32B of this section to estimate emissions from above grade metering-regulating stations that are not transmission-distribution transfer stations. 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 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 the facility has submitted a smaller number of annual reports than the duration of the selected cycle period (up to 5 years), then all available data from the current year and previous years must be used in the emission calculation. After the first cycle is completed, the survey will continue on a rolling basis by including the measurements from the current calendar year and as many of the previous calendar years as are needed to complete the survey cycle.

(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 (q) 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) 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, 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.

CountMR = Total number of meter/regulator runs at above grade metering-regulating stations that are not 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 paragraph (r)(6) 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.

(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 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 304 to calculate and report emissions.

(t) *GHG volumetric emissions using actual conditions.* If equation parameters in § 98.233 are already at standard conditions, 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) * * *

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

* * * * *

Za = Compressibility factor at actual conditions for natural gas. You may use 1 if the temperature is above -10 degrees Fahrenheit and pressure is below 5 atmospheres, or if the compressibility factor at the actual temperature and pressure is 0.98 or greater.

(2) * * *

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

* * * * *

Za = Compressibility factor at actual conditions for GHG i. You may use 1 if the compressibility factor at the actual temperature and pressure is 0.98 or greater.

* * * * *

(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.

* * * * *

(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 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.

P_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.

* * * * *

(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) * * *

* * * * *

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(c)(19) 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) * * *

$$Mass_{N2O} = \left(1\times10^{-3}\right)\times Fuel\times HHV\times EF \qquad \text{(Eq. W-40)}$$

* * * * *

$MassN_2O$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

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

HHV = Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For the higher heating value for field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

■ 6. Section 98.234 is amended by:

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

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

■ c. Adding paragraph (h).

The revisions 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.

* * * * *

(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, a required gas sample is not taken, or activity data are not collected), you must follow the procedures specified in paragraphs (a) through (h) of this section, as applicable.

(a) If you choose to take quarterly gas samples as allowed in § 98.233(d) in lieu of using a continuous gas analyzer, and there is a missing sample, you must substitute the average value of the last four samples for which data are available.

(b) If you did not conduct monitoring as specified in § 98.233(k) for a transmission storage tank(s), you must assume the vent stack(s) connected to the transmission storage tank(s) was leaking for the entire calendar year.

(c) 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.

(d) For each missing value of a parameter that should have been measured using 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.

(e) For the first six 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 six months of required data collection, facilities that are currently subject to this subpart W and that acquire new wells that were not previously subject to this subpart W may use best engineering estimates for any data related to those newly acquired wells that cannot reasonably be measured or obtained according to the requirements of this subpart.

(g) For each missing value of any activity data not described in this section, you must substitute data value(s) using the best available estimate(s) of the parameter(s), based on all available process 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).

■ 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.

(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 CO_2e of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (a)(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 (a)(1)(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 (a)(3)(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 (a)(4)(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 (a)(5)(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 (a)(6)(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 (a)(7)(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 (a)(8)(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 (b)(1)(ii) of this section.

(i) The total number of devices, determined according to § 98.233(a)(1) and (a)(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 (b)(1)(ii)(C) of this section.

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

(B) The number of devices 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) 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 (''Tt'' 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 (c)(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 (c)(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 (c)(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 (d)(2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (d)(1)(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.

(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 (for the onshore petroleum and natural gas production industry segment only).

(2) You must report information specified in paragraphs (d)(2)(i) through (d)(2)(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 (d)(2)(i)(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)(2)(ii)(D) of this section.

(A) 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 (d)(2)(iii)(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: absorbent 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 (e)(3).

(1) For each absorbent 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 (e)(1)(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 (e)(1)(xvi)(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 (e)(1)(xvii)(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 (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 (e)(5).

(xviii) Sub-basin ID (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 (e)(2)(v) of this section for the entire facility.

(i) The total number of dehydrators at the facility.

(ii) Whether any dehydrators reported in paragraph (e)(2)(i) of this section were vented to a vapor recovery device. If any dehydrators reported in paragraph (e)(2)(i) of this section 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 dehydrators reported in paragraph (e)(2)(i) of this section were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes. If any dehydrators reported in paragraph (e)(2)(i) of this section were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes, then you must specify the type of control device and the number of dehydrators at the facility that were vented to each type of control device.

(iv) Whether any dehydrators reported in paragraph (e)(2)(i) of this section were vented to a flare or regenerator firebox/fire tubes. If any dehydrators reported in paragraph (e)(2)(i) of this section were vented to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (e)(2)(iv)(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 dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (e)(2)(v)(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 (e)(5), where emissions are added together for all such dehydrators.

(B) Annual CH_4 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 (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 (e)(3)(iii) of this section for the entire facility.

(i) The same information specified in paragraphs (e)(2)(i) through (e)(2)(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 (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 (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 grouping 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 (f)(1)(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 grouping.

(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 grouping.

(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 § 98.233(f)(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 § 98.233(f)(4).

(xi) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xi)(A) through (f)(1)(xi)(E) of this section for each individual well not using a plunger lift that was tested during the year.

(A) API 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 (f)(1)(xii)(E) of this section for each individual well using a plunger lift that was tested during the year.

(A) The 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 (f)(2)(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 § 98.233(f)(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 § 98.233(f)(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 § 98.233(f)(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 (g)(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.

(3) Number of completions or workovers in the 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 (g)(5)(ii) of this section.

(i) Cumulative backflow time, in hours, for each sub-basin (''T_p'' in Equation W–10A).

(ii) Measured flowback rate, in standard cubic feet per hour, for each sub-basin (''$FR_{s,p}$'' in Equation W–12A).

(6) If you used Equation W–10B to calculate annual volumetric total gas emissions for completions that vent gas to the atmosphere, then you must report the vented natural gas volume, in standard cubic feet, for each well in the sub-basin (''$FV_{s,p}$'' 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 (h)(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 (h)(1)(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 backflow for all completions in the sub-basin category (the sum of all ''Tp'' 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).

(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 (h)(2)(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 backflow 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).

(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 (h)(3)(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 (h)(4)(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 type or by using flow meters. If you calculated emissions by equipment type, then you must report the information specified in paragraph (i)(1) of this section. If you calculated emissions using flow meters, then you must report the information specified in paragraph (i)(2) of this section.

(1) *Report by equipment type.* If you calculated emissions from blowdown vent stacks by equipment type, then you must report the equipment types and the information specified in paragraphs (i)(1)(i) through (i)(1)(iii) of this section for each equipment type. If a blowdown event resulted in emissions from multiple equipment types, then you must report the information in paragraphs (i)(1)(i) through (i)(1)(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 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 type).

(ii) Annual CO_2 emissions for the equipment type, in metric tons CO_2, calculated according to § 98.233(i)(2)(iii).

(iii) Annual CH_4 emissions for the equipment 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 (i)(2)(ii) of this section for the facility.

(i) Annual CO_2 emissions from all blowdown vent stacks at the facility, 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, 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 (j)(2) of this section as applicable. If 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 (j)(1)(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 gas-liquid separator oil volume that is sent to applicable onshore production storage tanks, in barrels.

(iv) The average gas-liquid separator temperature, in degrees.

(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 (j)(1)(xii)(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 (j)(1)(xiii)(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 (j)(1)(xiv)(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 paragraph (j)(2)(i) through (j)(2)(iii) of this paragraph.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (j)(2)(i)(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.

(B) An estimate of the fraction of oil throughput reported in paragraph (j)(2)(i)(A) 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) 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 (j)(2)(ii)(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.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin that vented gas directly to the atmosphere, calculated using Equation W–15 of this subpart.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (j)(2)(iii)(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 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 (j)(3)(iv) of this section.

(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 (''T_n'' 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 (k)(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 (k)(1)(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) Indicator whether scrubber dump valve leakage occurred for the transmission storage tank vent.

(iv) Indicator 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), 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 (k)(2)(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 venting occurred, in hours (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 (k)(3).

(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 (k)(3).

(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 (k)(3)(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 (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)(4).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from flaring gas, calculated according to § 98.233(k)(4).

(vi) Annual N_2O emissions, in metric tons N_2O, that resulted from flaring gas, calculated according to § 98.233(k)(4).

(l) *Well testing.* You must indicate whether you performed gas well or oil well testing, and if the testing of gas wells or oil wells resulted in vented or flared emissions during the calendar year. If you performed well testing that resulted in vented or flared emissions during the calendar year, then you must report the information specified in paragraphs (l)(1) through (l)(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 (l)(1)(vi) of this section.

(i) Number of wells tested in the calendar year.

(ii) Average number of well testing days 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.

(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 (l)(2)(vii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Average number of well testing days 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.

(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 (l)(3)(v) of this section.

(i) Number of wells tested in the calendar year.

(ii) Average number of well testing days in the calendar year.

(iii) Average annual production rate for well(s) tested, in actual cubic feet per day.

(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 (l)(4)(vi) of this section.

(i) Number of wells tested in calendar year.

(ii) Average number of well testing days in the calendar year.

(iii) Average annual production rate for well(s) tested, in actual cubic feet per day.

(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 (m)(9) of this section for each sub-basin.

(1) Sub-basin ID.

(2) Indicator whether any associated gas was vented directly to the atmosphere without flaring.

(3) Indicator 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).

(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 this subpart).

(7) Total volume of emissions reported elsewhere, in standard cubic feet, during time periods in which associated gas was vented or flared and which are calculated and reported under other paragraphs of this section, in standard cubic feet (the sum of ''EREp,q'' values used in Equation W–18 of this subpart).

(8) If you had associated gas emissions directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(8)(i) through (m)(8)(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 (m)(4).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(3) and (m)(4).

(9) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(9)(i) through (m)(9)(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 (n)(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 (''Va'' in Equation W–19 of this subpart).

(5) Fraction of the feed gas sent to an un-lit flare (''Zu'' 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 (o)(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 (o)(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 (o)(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 (o)(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 (o)(1)(xvi) of this section for each 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 whether any compressor sources are part of a manifolded group of compressor sources.

(vii) Indicate whether any compressor sources are routed to a flare.

(viii) Indicate whether any compressor sources have vapor recovery.

(ix) Indicate whether emissions from any compressor sources are captured for fuel use or are routed to a thermal oxidizer.

(x) Indicate whether the compressor has blind flanges installed.

(xi) Indicate whether the compressor has wet or dry seals.

(xii) If the compressor has wet seals, the number of wet seals.

(xiii) Compressor power rating (hp).

(xiv) Year compressor was installed.

(xv) Compressor model name and description.

(xvi) Date of last maintenance shutdown that compressor was depressurized.

(2) Compressor source emission vent. For each compressor source at each compressor, report the information specified in paragraphs (o)(2)(i) through (o)(2)(viii) of this section.

(i) Centrifugal compressor name or ID. Use the same ID as in paragraph (o)(1)(i) of this section.

(ii) Centrifugal compressor source (wet seal, isolation valve, or blowdown valve).

(iii) Unique name or ID for the emission vent. If the emission vent is connected to a manifolded group of compressor sources, use the same emission vent ID for each compressor source.

(iv) Emission vent type. Indicate whether the emission vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the emission vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(v) Indicate whether an as found leak measurement(s) as identified in § 98.233(o)(2) or (o)(4) was conducted on the emission vent.

(vi) Indicate whether continuous leak measurements as identified in § 98.233(o)(3) or (o)(5) were conducted on the emission vent.

(vii) Report emissions as specified in paragraphs (o)(2)(vii)(A) and (o)(2)(vii)(B) of this section for the emission vent. For emission vents associated with individual compressor sources that use an as found leak measurement(s), calculate emissions by summing all emissions from all compressor mode-source combinations for the emission vent.

(A) Annual CO_2 emissions, in metric tons CO_2.

(B) Annual CH_4 emissions, in metric tons CH_4.

(viii) If the emission vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational.

(3) As found leak measurement sample data. If the measurement methods specified in paragraphs § 98.233(o)(2) or (o)(4) are conducted, report the information specified in paragraph (o)(3)(i) of this section. If the measurement method specified in paragraph § 98.233(o)(2) is performed, report the information specified in paragraph (o)(3)(ii) of this section.

(i) For each as found leak measurement performed on an emission vent, report the information specified in paragraphs (o)(3)(i)(A) through (o)(3)(i)(E) of this section.

(A) Name or ID of emission vent. Use same emission vent ID as in paragraph (o)(2)(iii) of this section.

(B) Sample date.

(C) Leak measurement method.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the emission vent, report the mode of operation the compressor was in when the sample was taken.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in equation W–24 was used to calculate emissions in Equation W–23, report the information specified in paragraphs (o)(3)(ii)(A) through (o)(3)(ii)(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 ($EF_{m,s}$ in Equation W–24).

(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–24).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or corporate.

(4) Continuous leak measurement data. If the measurement methods specified in paragraphs § 98.233(o)(3) or (o)(5) are conducted, report the information specified in paragraphs (o)(4)(i) and (o)(4)(ii) of this section for each continuous measurement conducted on each emission vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of emission vent. Use same emission vent ID as in paragraph (o)(2)(iii) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(5) 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 (o)(5)(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 (p)(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 (p)(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 (p)(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 (p)(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 (p)(1)(xvi) of this section for each compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-depressurized-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-depressurized-mode.

(vii) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(viii) Indicate whether any compressor sources are part of a manifolded group of compressor sources.

(ix) Indicate whether any compressor sources are routed to a flare.

(x) Indicate whether any compressor sources have vapor recovery.

(xi) Indicate whether emissions from any compressor sources are captured for fuel use or are routed to a thermal oxidizer.

(xii) Indicate whether the compressor has blind flanges installed.

(xiii) Compressor power rating (hp).

(xiv) Year compressor was installed.

(xv) Compressor model name and description.

(xvi) Date of last maintenance shutdown for rod packing replacement.

(2) Compressor source emission vent. For each compressor source at each compressor, report the information specified in paragraphs (p)(2)(i) through (p)(2)(viii) of this section.

(i) Reciprocating compressor name or ID. Use the same ID as in paragraph (p)(1)(i) of this section.

(ii) Reciprocating compressor source (isolation valve, blowdown valve, or rod packing).

(iii) Unique name or ID for the emission vent. If the emission vent is connected to a manifolded group of compressor sources, use the same emission vent ID for each compressor source.

(iv) Emission vent type. Indicate whether the emission vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the emission vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(v) Indicate whether an as found leak measurement(s) as identified in § 98.233(p)(2) or (p)(4) was conducted on the emission vent.

(vi) Indicate whether continuous leak measurements as identified in § 98.233(p)(3) or (p)(5) were conducted on the emission vent.

(vii) Report emissions as specified in paragraphs (p)(2)(vii)(A) and (p)(2)(vii)(B) of this section for the emission vent. For emission vents associated with individual compressor sources that use an as found leak measurement(s), calculate emissions by summing all emissions from all compressor mode-source combinations for the emission vent.

(A) Annual CO_2 emissions, in metric tons CO_2.

(B) Annual CH_4 emissions, in metric tons CH_4.

(viii) If the emission vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational.

(3) As found leak measurement sample data. If the measurement methods specified in paragraphs § 98.233(p)(2) or (p)(4) are conducted, report the information specified in paragraph (p)(3)(i) of this section. If the measurement method specified in paragraph § 98.233(p)(2) is performed, report the information specified in paragraph (p)(3)(ii) of this section.

(i) For each as found leak measurement performed on an emission vent, report the information specified in paragraphs (p)(3)(i)(A) through (p)(3)(i)(E) of this section.

(A) Name or ID of emission vent. Use same emission vent ID as in paragraph (p)(2)(iii) of this section.

(B) Sample date.

(C) Leak measurement method.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the emission vent, report the mode of operation the compressor was in when the sample was taken.

(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 (p)(3)(ii)(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 ($EF_{m,s}$ 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 corporate.

(4) Continuous leak measurement data. If the measurement methods specified in paragraphs § 98.233(p)(3) or (p)(5) are conducted, report the information specified in paragraphs (p)(4)(i) and (p)(4)(ii) of this section for each continuous measurement conducted on each emission vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of emission vent. Use same emission vent ID as in paragraph (p)(2)(iii) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(5) Reciprocating compressors in onshore petroleum and natural gas production must report the information specified in paragraphs (p)(5)(i) through (p)(5)(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 (q)(2) of this section. Natural gas distribution facilities 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) 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 (q)(2)(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 (q)(2)(v) of this section but report a zero (''0'') for the information required according to paragraphs (q)(2)(iii), (q)(2)(iv), and (q)(2)(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 were found 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.

(v) Annual CH_4 emissions, in metric tons CH_4, for the component type.

(3) Natural gas distribution facilities must report the information specified in paragraphs (q)(3)(i) through (q)(3)(viii) 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 meter/regulator run operating hour (''$EF_{s,MR,i}$'' 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 meter/regulator run operating hour (''$EF_{s,MR,i}$'' for CH_4 calculated using Equation W–31 of this subpart).

(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 paragraph (r)(1) of this section. Natural gas distribution facilities must also report the information specified in paragraph (r)(2) of this section. Onshore petroleum and natural gas production facilities must also report the information specified in paragraph (r)(3) of this section.

(1) You must indicate whether your facility contains any of the emission source types covered by § 98.233(r), for the applicable industry segment. You must report the information specified in paragraphs (r)(1)(i) through (r)(1)(v) of this section separately for each emission source type that is located at your facility. Onshore petroleum and natural gas production facilities must report the information specified in paragraphs (r)(1)(i) through (r)(1)(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 (q)(2)(i) through (q)(2)(viii) of this 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) Number of below grade transmission-distribution transfer stations at the facility.

(iv) Number of below grade metering-regulating stations that are not transmission-distribution transfer stations at the facility.

(v) 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).

(vi) Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run (''$T_{w,avg}$'' in Equation W–32B of this subpart).

(vii) Annual CO_2 emissions, in metric tons CO_2, from above grade metering regulating stations that are not above grade transmission-distribution transfer stations.

(viii) 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 (r)(3)(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 (r)(3)(ii)(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 (s)(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 (w)(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 (x)(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 (z)(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 (z)(1)(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 (z)(2)(vi) 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 (z)(2).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) and (z)(2).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) and (z)(2).

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (aa)(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 (aa)(1)(ii) of this section.

(i) Report the information specified in paragraphs (aa)(1)(i)(A) through (aa)(1)(i)(D) 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 produced in the calendar year for sales, not including lease condensates, in barrels.

(D) The quantity of lease condensate produced in the calendar year for sales, in barrels.

(ii) Report the information specified in paragraphs (aa)(1)(ii)(A) through (aa)(1)(ii)(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.

(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 taken out of production 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) through (aa)(2)(iii) of this section.

(i) The quantity of gas produced from the offshore platform in the calendar year for sales, in thousand standard cubic feet.

(ii) The quantity of oil produced from the offshore platform in the calendar year for sales, in barrels.

(iii) The quantity of condensate produced from the offshore platform in the calendar year for sales, in barrels.

(3) For natural gas processing, report the quantities specified in paragraphs (aa)(3)(i) through (aa)(3)(vii) of this section.

(i) The quantity of produced 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 quantity of NGLs (bulk and fractionated) received at the gas processing plant in the calendar year, in barrels.

(iv) The quantity of NGLs (bulk and fractionated) leaving the gas processing plant in the calendar year, in barrels.

(v) Average mole fraction of CH_4 in produced gas received.

(vi) Average mole fraction of CO_2 in produced 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 (aa)(4)(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 (aa)(5)(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 (aa)(8)(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 (aa)(9)(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 paragraphs (bb)(1) through (bb)(5) in this section for each individual missing data value used in a calculation. Aggregation of missing data values within a component, well, sub-basin, or basin is not acceptable. If missing data is substituted for the same parameter in non-consecutive periods during the calendar year, the information in paragraphs (bb)(1) through (bb)(5) in this section should be reported for each period separately.

(1) The date(s) the missing data is used.

(2) The equation(s) in which the missing data is used.

(3) The description of the unique or unusual circumstance that led to missing data use, including information on any equipment or components involved and any procedures that were not followed.

(4) The description of the procedures used to substitute an unavailable value of a parameter.

(5) The description of how the owner or operator will avoid the use of missing data in the future, such as mitigation strategies or changes to standard operating procedures.

■ 9. 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 any type of vent or valve (i.e., wet seal, blowdown valve, isolation valve, or rod packing) on a centrifugal or reciprocating compressor.

* * * * *

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. At least one meter, at least on 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 that is otherwise vented is 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 no direct release to the atmosphere.

Reduced emissions workover means a well workover with hydraulic fracturing (i.e., refracturing) where gas flowback that is otherwise vented is 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 no direct release to the atmosphere.

* * * * *

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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