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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2014–0831; FRL—9918–48–OAR]

RIN 2060–AS37

Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing revisions and confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Program. In particular, the EPA is proposing to add calculation methods and reporting requirements for greenhouse gas emissions from gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing, and blowdowns of natural gas transmission pipelines between compressor stations. The EPA is also proposing well identification reporting requirements to improve the EPA's ability to verify reported data and enhance transparency. This action also proposes confidentiality determinations for new data elements contained in these proposed amendments.

DATES: Comments must be received on or before February 9, 2015.

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 December 16, 2014. If requested, the hearing will be conducted on December 24, 2014, in the Washington, DC area. The EPA will provide further information about the hearing on the Greenhouse Gas Reporting Program 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–2014–0831 by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Email: A-and-R-Docket*@epa.gov. Include Docket ID No. EPA–HQ–OAR–2014–0831 or RIN No. 2060–AS37 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. EPA–HQ–OAR–2014–0831, 1200 Pennsylvania Avenue NW., Washington, DC 20460. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.
- *Hand/Courier Delivery:* EPA Docket Center, Room 3334, EPA WJC West Building, 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 6207A, 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–2014–0831, Greenhouse Gas Reporting Rule: 2015 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–2014–0831. 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–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343–9263; fax number:

(202) 343–2342; email address: *GHGReportingRule@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Program 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 the EPA's Greenhouse Gas Reporting Program 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 [a]	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.

[a] North American Industry Classification System.

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.

API American Petroleum Institute
BAMM best available monitoring methods
Btu British thermal unit
CAA Clean Air Act
CBI confidential business information
CFR Code of Federal Regulations
CO_2 carbon dioxide
CO_2e carbon dioxide equivalent
EPA Environmental Protection Agency
EIA Energy Information Administration
FERC Federal Energy Regulatory Commission
FR Federal Register
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GOR gas-to-oil ratio
ICR Information Collection Request
ISBN International Standard Book Number
LDC local distribution company
MMscfd million standard cubic feet per day
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NGO non-government organization
NGPA Natural Gas Policy Act
NTTAA National Technology Transfer and Advancement Act of 1995
OMB Office of Management and Budget
PPDM Professional Petroleum Data Management
REC reduced emission completion
RFA Regulatory Flexibility Act
SBA Small Business Administration
SBREFA Small Business Regulatory Enforcement and Fairness Act
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 proposed amendments. This section also discusses the EPA's legal authority under the CAA to promulgate and amend 40 CFR part 98 (hereafter 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 data reporting elements. 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

The EPA's Greenhouse Gas Reporting Program (GHGRP) requires annual reporting of GHG data and other relevant information from large sources and suppliers in the United States. On October 30, 2009, the EPA published Part 98 for collecting information regarding GHG emissions from a broad range of industry sectors (74 FR 56260). Although reporting requirements for petroleum and natural gas systems were originally proposed to be part of Part 98 (75 FR 16448, April 10, 2009), the final October 2009 rule did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA re-proposed subpart W in 2010 (79 FR 18608; April 12, 2010), and a subsequent final rule was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458) (hereafter referred to as ''the 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, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014).

In this current proposal, the EPA is proposing to amend subpart W to require the reporting of GHG emissions from several sources that have not previously been included in subpart W. These sources include oil well completions and workovers with hydraulic fracturing, petroleum and natural gas gathering and boosting systems, and transmission pipeline blowdowns between compressor stations. The proposed reporting requirements for oil well completions and workovers with hydraulic fracturing would be included as part of the existing Onshore Petroleum and Natural Gas Production industry segment. For the other sources, the EPA is proposing two new industry segments: the Onshore Petroleum and Natural Gas Gathering and Boosting segment for petroleum and natural gas gathering and boosting facilities, and Onshore Natural Gas Transmission Pipeline for transmission pipeline blowdowns between compressor stations. The EPA is also proposing to require the reporting of a well identification number for oil and gas wells covered in the Onshore Petroleum and Natural Gas Production segment.

The EPA is proposing these changes for several reasons. First, we have been working to enhance the quality of data from petroleum and natural gas systems gathered through Part 98, because it has been an important tool for the EPA and the public to analyze emissions, identify opportunities for improving the data, and understand emissions trends. One of the strengths of the GHGRP's petroleum and natural gas systems data is that it provides a better understanding of sources in the petroleum and natural gas industry for which the public previously had little information. For example, the data that would be collected through these proposed revisions could inform updates to the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* [1] (hereafter referred to as the ''U.S. GHG Inventory''). These proposed revisions reflect the fact that this sector has been growing and changing rapidly since the GHGRP's petroleum and natural gas systems requirements were originally promulgated in 2010. Greenhouse gas reporting from gathering and boosting systems was proposed in 2010 but was not finalized due to the need to conduct additional analysis. Emissions from the sources the EPA is proposing to include are not reported under the GHGRP with the exception of emissions from completions and workovers of oil wells with hydraulic fracturing that are flared and emissions from sources in the Onshore Petroleum and Natural Gas Gathering and Boosting segment that are required to report as combustion sources under subpart C of Part 98. Aside from those exceptions, which only include emissions associated with combustion and do not capture the majority of methane emissions from these sources, a nationally comprehensive data set of the emissions from the sources the EPA is proposing to include does not currently exist in the public domain. The EPA anticipates that these emission sources will be an important part of establishing a comprehensive data set for the petroleum and natural gas industry based on data available in the U.S. GHG Inventory and other sources. For more information, please see ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2014–0831. If finalized, this rule would further the EPA's goal of improving the completeness, quality, accuracy, and transparency of data from this sector (79 FR 74484, November 30, 2010), improving the ability of agencies and the public to use these GHG data to analyze emissions and understand emission trends. Adding well identification numbers to the required reporting for oil and gas wells covered by the Onshore Petroleum and Natural Gas Production segment would enable the EPA and other stakeholders to directly match data for reported wells with other local, state, and federal permitting and data reporting information, as it is the common identification number used for wells in the United States (U.S.).

Second, a key element of the President's *Climate Action Plan* is the *Strategy to Reduce Methane Emissions,* which the Administration announced on March 28, 2014. [2] The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector. In this strategy, the EPA was specifically tasked with continuing to review regulatory requirements to address potential gaps in coverage, improve methods, and help ensure high quality data reporting. The proposed revisions to subpart W covered in this action would address data gaps, specify methods for measuring methane emissions, and provide data that could be used to further analyze methane emissions in this industry.

Third, on March 19, 2013, the EPA received a petition from a group of non-government organizations (NGOs) asking that the EPA collect data from emissions sources not currently included in subpart W, including well completion emissions from oil wells that co-produce natural gas, facilities and pipelines in the gathering and boosting segment, and transmission pipeline blowdown events, because these sources could be significant

[1] U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012.* April 15, 2014. EPA 430–R–14–003. This report tracks total annual U.S. emissions and removals by source, economic sector, and greenhouse gas going back to 1990. It is updated annually, and the latest version (cited here) covers emissions through 2012.

[2] *Climate Action Plan—Strategy to Reduce Methane Emissions.* The White House, Washington, DC, March 2014. Available at *http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014–03–28_final.pdf.*

sources of emissions that are not being reported. The NGOs also asked the EPA to require the reporting of API well identification numbers (currently known as US Well Numbers) to allow cross-reference to production data and other important information, to phase out the use of best available monitoring methods (BAMM), and to consider including ''Advanced Innovative Monitoring Methods'' to ''accelerate development and deployment of real-time continuous methane emission monitoring.''[3] These proposed revisions, which address this petition, are consistent with the EPA's intent to ''collect complete and accurate facility-level GHG emissions from the petroleum and natural gas industry'' (79 FR 74484, November 30, 2010) and to provide accurate and transparent data to inform future policy decisions. Today's proposal includes the reporting of emissions currently not covered under subpart W as well as reporting of well identification numbers which would help ensure complete, accurate, and transparent reporting of GHG data under subpart W. The EPA is proposing to allow BAMM for a limited time only for sources affected by these proposed changes; the use of BAMM for sources not addressed by the proposed changes in this action was addressed on November 25, 2014 (79 FR 70352). Finally, the EPA is currently assessing the potential opportunities for applying innovations in measurement technology to identifying and estimating emissions from affected sources under subpart W. While not explicitly adding new, alternative monitoring methods in this proposal, the EPA is seeking comment on options for allowing use of alternative monitoring methods under the GHGRP to account for advances in technology. See also, ''Discussion Paper on Potential Implementation of Alternative Monitoring under the GHGRP'' in Docket ID No. EPA–HQ–OAR–2014–0831.

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 data elements in subpart W under its authorities provided in sections 114, 301, and 307 of the CAA. Section 114(c) of the CAA 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 proposed rule is subject to the provisions of section 307(d) of the CAA.

D. How would these amendments apply to 2015 and 2016 reports?

The EPA is planning to address the comments we receive on these proposed changes and publish the final amendments before the end of 2015. If finalized according to this schedule, these amendments would become effective on January 1, 2016. Facilities would therefore be required to follow the revised methods in subpart W, as amended, to calculate, monitor, and report emissions beginning January 1, 2016. The first annual reports of emissions calculated using the amended requirements would be those submitted by March 31, 2017, which would cover the 2016 emissions reporting. For the 2015 emissions and the corresponding reports due by March 31, 2016, reporters would continue to calculate, monitor, and report emissions and other relevant data according to the requirements of 40 CFR part 98 that are applicable during the 2015 calendar year.

For 2016 emissions only, the EPA is proposing to allow the use of short-term transitional BAMM for reporters who would be subject to new monitoring requirements associated with these proposed revisions. The use of BAMM would provide flexibility for the first-time monitoring of new emissions sources. These reporters would have the option of using BAMM from January 1, 2016 to March 31, 2016 without seeking prior EPA approval. Reporters would also have the opportunity to request an extension for the use of BAMM from April 1, 2016 through December 31, 2016; those owners or operators would be required to submit a request to the EPA by January 31, 2016. See Section II.F of this preamble for more information.

II. Revisions and Other Amendments

A. Oil Wells With Hydraulic Fracturing

Subpart W requires the reporting of GHG emissions from gas well completions and workovers with hydraulic fracturing in the Onshore Petroleum and Natural Gas Production segment, but it does not require the reporting of GHG emissions from oil well completions and workovers with hydraulic fracturing (unless the emissions are routed to a flare, in which case the emissions would be calculated as part of the flare stacks emission source, or the well testing emissions are vented or flared, in which case the emissions would be calculated as part of the well testing venting and flaring emission source). At the time the EPA finalized the subpart W requirements (75 FR 74458, November 30, 2010), hydraulic fracturing of gas wells was a well-established and widespread industry practice. However, since that time, expansion of the use of horizontal drilling and hydraulic fracturing has allowed drilling into new formations, leading to increased emissions associated with hydraulic fracturing.[4] Because hydraulic fracturing allows access to new geologic formations, some of these activities are occurring from completions and workovers with hydraulic fracturing of wells considered to be in oil formations according to the definition of ''sub-basin category, for onshore natural gas production'' in 40 CFR 98.238. Since subpart W does not currently capture these emissions from oil wells with hydraulic fracturing, the EPA is proposing to close this data gap by proposing reporting requirements for oil well completions and workovers with hydraulic fracturing.

The EPA is proposing to amend subpart W: (1) To clarify the applicability of the current provisions for the reporting of GHG emissions from completions and workovers with hydraulic fracturing for wells in the Onshore Petroleum and Natural Gas Production segment, regardless of whether their primary product is oil or natural gas, and (2) to include provisions for the reporting of GHG emissions from oil well completions and workovers with hydraulic fracturing. Consistent with the current requirements for gas well completions

[3] *Petition for Rulemaking and Interpretive Guidance Ensuring Comprehensive Coverage of Methane Sources Under Subpart W of the Greenhouse Gas Reporting Rule—Petroleum And Natural Gas Systems;* Submitted by Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club; March 19, 2013.

[4] U.S. EPA Office of Air Quality Planning and Standards (OAQPS). *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas During Ongoing Production: Report for Oil and Natural Gas Sector, Oil Well Completions and Associated Gas During Ongoing Production Review Panel.* April 2014. Available at *http://www.epa.gov/airquality/oilandgas/pdfs/20140415completions.pdf.*

and workovers with hydraulic fracturing, the proposed provisions include the reporting of activity data on the number of oil wells with hydraulic fracturing and on the use of flaring and reduced emission completions (RECs). The EPA is also proposing to update equations and definitions accordingly under 40 CFR 98.233(g) to reflect applicability to completions and workovers of all wells with hydraulic fracturing.

The proposed monitoring methods and reporting requirements would incorporate methods that are already in subpart W for hydraulic fracturing of gas wells. The feasibility of the methods have been demonstrated and refined through several years of reporting and earlier amendments to subpart W. Specifically, the EPA is proposing to require the use of either Equation W–10A or W–10B in the current rule for calculating GHG emissions from oil well completions and workovers with hydraulic fracturing. Equation W–10A is used to calculate emissions from wells using inputs obtained from a representative sample of wells within a sub-basin and the ratio of the gas flowback rate to the production flow rate, and Equation W–10B is used to calculate emissions using inputs obtained from all wells within a sub-basin and the flow rate and flow volume of the gas vented or flared. Emissions would be calculated and reported separately for gas wells and oil wells. Within subpart W, an individual well is labeled an ''oil well'' or ''gas well'' depending on the formation type reported for that well. If wells produce from more than one formation type, then the well is classified into only one type based on the formation type with the most contribution to production as determined by the reporter's engineering knowledge. Furthermore, the EPA is proposing to require Calculation Method 1 for calculating inputs to Equations W–12A and W–12B for oil wells. Calculation Method 1 relies on direct measurement of gas flow rate during flowback to develop calculation inputs. The EPA is proposing that subpart W would include the same requirements for the location of the flow meter used to measure the gas flow rate for an oil well as for the flow meter on a gas well. The EPA is seeking comment on whether this is the appropriate location for the oil well flow meter. The EPA is also seeking comment on the burden of requiring direct measurement of gas flow rate during flowback.

The EPA is also aware that operators of oil wells with a relatively low gas-to-oil ratio (GOR) may not meter gas during the completion phase or even during the production phase. Instead, the associated natural gas may be vented or flared without measuring the gas flow rate. For these oil wells that do not meter gas production, the EPA is proposing to add a new Equation W–12C to calculate, rather than measure, the value of $PR_{s,p}$ (the average gas production flow rate during the first 30 days of production after the completion or workover), which is used as an input to Equation W–10A. In this proposed Equation W–12C, the value of $PR_{s,p}$ would be calculated by multiplying the GOR of the well by the measured oil production rate during the first 30 days of production after the completion or workover to calculate average gas production flow rate.

The EPA is not proposing at this time to allow the use of calculated flowback rate for oil wells based on well parameters, as specified in Calculation Method 2 in 40 CFR 98.233(g). In the current subpart W, Calculation Method 2 uses the measured gas pressure differential across the well choke to estimate gas flow rate. Based on the information available, the EPA concluded that this methodology may not be appropriate for estimating emissions from oil well completions because of the differences in operational conditions between oil and gas production. The EPA is seeking comment on how an engineering estimate of gas flow rate for oil wells might be performed as an alternative to the proposed monitoring methods that would require direct measurement of gas flow rate. Such an engineering estimate would be analogous to the current Calculation Method 2, but with alternatives to the current Equations 11–A and 11–B that would be applicable to oil wells. If an appropriate and technically sound approach can be identified, an engineering estimate methodology analogous to Calculation Method 2 for gas wells would reduce the burden for reporters of oil well completions and workovers with hydraulic fracturing.

Additionally, the EPA is seeking comment on whether to establish a minimum GOR threshold such that oil wells with a very low GOR would not be subject to the monitoring and reporting requirements for GHG emissions from completions and workovers with hydraulic fracturing. The EPA is also soliciting data and other supporting information that could be used to establish a level for that threshold in the final rule amendments, if that approach were adopted. Supporting data should include, at a minimum, information sufficient to identify the location of any wells for which data are provided (*e.g.,* US Well Number), the measured GOR, and whether the GOR for the well was measured during completion or workover. Information that would allow the EPA to estimate the typical emissions from wells with such a low GOR, and to estimate the total emissions from all wells that would be exempt if such a threshold were established, would be particularly helpful to inform potential inclusion of a GOR threshold in the final rule. The EPA particularly solicits specific data, rather than conclusory statements, to support commenters' positions on whether the EPA should include a minimum GOR threshold for monitoring and reporting.

The EPA is also seeking comment on whether to establish a minimum well pressure such that oil wells operating below a certain pressure would not be subject to the monitoring and reporting requirements for GHG emissions from completions and workovers with hydraulic fracturing. Similar to the discussion on a potential GOR threshold above, the EPA is also soliciting data and other supporting information that could be used to establish a level for the well pressure threshold in the final rule amendments, if that approach were adopted. Supporting data should include, at a minimum, information sufficient to identify the location of any wells for which data are provided (*e.g.,* US Well Number), the measured well pressure, and whether the well pressure was measured during completion or workover. Information that would allow the EPA to estimate the typical emissions from wells with low well pressures, and to estimate the total emissions from all wells that would be exempt if such a threshold were established, would be particularly helpful to inform potential inclusion of a well pressure threshold in the final rule. The EPA particularly solicits specific data, rather than conclusory statements, to support commenters' positions on whether the EPA should include a minimum well pressure threshold for monitoring and reporting.

B. Onshore Petroleum and Natural Gas Gathering and Boosting Segment

The EPA is proposing to add a new industry segment to subpart W, Onshore Petroleum and Natural Gas Gathering and Boosting, that would cover emissions from equipment used by gathering pipeline systems that move petroleum and natural gas from the well to either larger gathering pipeline systems, natural gas processing plants, natural gas transmission pipelines, or natural gas distribution pipelines. A gathering and boosting system is a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more well-defined connection points to gas and oil production and a well-defined downstream endpoint, typically a gas processing plant or transmission pipeline. Gathering pipelines are pipelines used to transport gas from the furthermost downstream point in an onshore production facility to certain endpoints, generally either a gas processing facility or point of connection to a transmission pipeline. Compressors located along the gathering and boosting system are used to control or ''boost'' the pressure of the gas in the pipeline and keep the gas moving downstream. Acid gas removal units and dehydrators may also be located on the gathering and boosting system to treat the collected natural gas. There are two types of gathering and boosting systems, radial and trunk line. The radial type brings all the pipelines to a central header, while the trunk-line type uses several remote headers to collect fluid and is mainly used in large fields.

The EPA recognized the need to require reporting from gathering and boosting systems in an earlier GHGRP proposed rule. Gathering lines and boosting stations were included in the original subpart W proposal (75 FR 18608, April 12, 2010) under both the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment. The EPA originally proposed to include reporting of emissions from intra-facility gathering lines and all systems engaged in gathering produced gas from multiple wells as part of the Onshore Petroleum and Natural Gas Production segment. The EPA also proposed that field gathering and boosting stations that gather and process natural gas from multiple wellheads and compress and transport natural gas as feed to natural gas processing facilities would be included in the Onshore Natural Gas Processing segment.

In response to the April 2010 proposal, the EPA received 32 comment letters addressing numerous aspects of the proposed gathering and boosting reporting requirements. The comments generally focused on the areas of ownership of the gathering and boosting system, and on determining the boundaries of gathering and boosting between the Onshore Petroleum and Natural Gas Production and Onshore Natural Gas Processing segments. The commenters were also concerned with the burden of the proposed reporting requirements for the gathering and boosting systems. These comments were summarized in the preamble to the final subpart W rule (75 FR 74458, November 30, 2010) and can be found in the EPA's Response to Public Comments document for the final rule.[5]

In response to public comments, the EPA recognized the need for further analysis of gathering and boosting before developing reporting requirements. As a result, gathering and boosting sources were not included in the final subpart W rule published in November 2010, and the EPA stated that we would continue to evaluate ''the most appropriate mechanism for future actions to address the collection of appropriate data on gathering lines and boosting stations'' (75 FR 74469, November 30, 2010). After further consideration of the comments and collection of additional data, the EPA is proposing to require reporting of petroleum and natural gas gathering and boosting equipment as part of a new Onshore Petroleum and Natural Gas Gathering and Boosting segment to collect the data needed to quantify the emissions from this segment and to achieve more complete coverage of the petroleum and natural gas systems sector.

The EPA is proposing to define the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230 as gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the gas to a natural gas processing facility, a natural gas transmission pipeline, or a natural gas distribution pipeline. Gathering and boosting equipment would include, but would not be limited to, gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. The Onshore Petroleum and Natural Gas Gathering and Boosting segment would not include equipment and pipelines that are reported under any other industry segment defined in subpart W.

The EPA is proposing to define a gathering and boosting system as a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, local distribution company (LDC) pipeline, or other gathering and boosting system. The EPA is proposing to define a gathering and boosting system owner or operator as any person that: (1) Holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline; or (2) is responsible for custody of the gas transported. The purpose of including the last phrase of the definition is to address ownership scenarios for vertically integrated companies for which contracts are not needed to transfer gas from production wells to natural gas processing plants. The EPA requests comment on whether this phrase addresses that concern.

The EPA is proposing to define a facility with respect to onshore petroleum and natural gas gathering and boosting in 40 CFR 98.238 as all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in 40 CFR 98.238. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting systems and equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, would be considered to be under common control of the owner or operator of the gathering and boosting system. Emissions from an onshore petroleum and natural gas gathering and boosting facility would only need to be reported if the collection of emission sources emits 25,000 metric tons of carbon dioxide equivalent (CO_2e) or more per year. The basin-level reporting approach that the EPA is proposing for onshore petroleum and natural gas gathering and boosting facilities is currently being used for reporting in the Onshore Petroleum and Natural Gas Production sector. The proposed basin-level approach for the Onshore Petroleum and Natural Gas Gathering and Boosting

[5] U.S. Environmental Protection Agency Office of Atmosphere Programs, Climate Change Division. *Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments*, November 2010. Docket Item No. EPA–HQ–OAR–2009–0923–3608.

segment would achieve a balance of providing geographically specific information, while also reducing burden on reporters by ensuring that owners/operators of gathering and boosting systems would only have to submit one report for all their systems within a basin. For more information on this analysis, please see ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' in Docket ID No. EPA–HQ–OAR–2014–0831.

The EPA believes that the proposed definitions of the Onshore Petroleum and Natural Gas Gathering and Boosting segment, facility, and owner/operator address or avoid the major issues raised by the commenters in response to the April 2010 proposal. Defining the Onshore Petroleum and Natural Gas Gathering and Boosting segment as a segment separate from the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment would avoid many of the boundary issues presented by the earlier proposal. The proposed definition of facility would also clarify how equipment located along the pipeline should be treated as part of the facility. The EPA requests comment on the definitions of the Onshore Petroleum and Natural Gas Gathering and Boosting segment and facility, the gathering and boosting system, the gathering and boosting system owner or operator, the determination of what emission sources are included in a petroleum and natural gas gathering and boosting facility in complex ownership scenarios (for example, multiple owners with operation handled by one of the owners or shared by multiple owners). In complex ownership scenarios, the EPA is proposing that the owners/operators would assign a designated representative responsible for reporting consistent with 40 CFR 98.4, and the EPA requests comment on whether the provisions of 40 CFR 98.4 are appropriate for petroleum and natural gas gathering and boosting facilities with complex ownership scenarios. In addition, the EPA requests comment on whether the proposed definitions clearly define the boundary of the Onshore Petroleum and Natural Gas Gathering and Boosting segment as the pipelines and equipment between the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment (or other downstream segment).

The EPA also requests comment on potential concerns with overlap of these boundaries and whether specific provisions are needed to address the overlap. For example, the EPA considered whether provisions were needed to address the potential for some non-fractionating processing plants with an annual throughput of around 25 million standard cubic feet per day (MMscfd) to be required to report as part of different industry segments from year to year (*i.e.,* as part of Onshore Petroleum and Natural Gas Gathering and Boosting if the annual average daily throughput drops below 25 MMscfd one year and then part of the Onshore Natural Gas Processing segment if the throughput increases to above 25 MMscfd the next year). The EPA considered a provision that would allow a non-fractionating processing facility to stop reporting as part of the Onshore Natural Gas Processing segment and instead report as part of the Onshore Petroleum and Natural Gas Gathering and Boosting segment if the facility throughput is below 25 MMscfd for 5 consecutive years. The EPA is not proposing to include this provision because there is not sufficient information available on gathering and boosting systems for the EPA to assess whether such a provision is necessary, but the EPA is requesting comment on the need for a provision that addresses overlap of segment boundaries and what that provision should include.

The EPA is proposing to use current methods in subpart W, when available, for monitoring and calculating emissions from the Onshore Petroleum and Natural Gas Gathering and Boosting segment. Subpart W already contains monitoring and calculation methods for all emission sources that would be included in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, with the exception of gathering pipelines, in either the Onshore Petroleum and Natural Gas Production segment or the Onshore Natural Gas Processing segment. Since similar equipment and sources are included in multiple segments, this approach allows the EPA to rely on methods that have been proven effective for collecting GHG data for at least 3 years. This approach is expected to provide high quality data while reducing the burden on reporters that would be associated with determining how to implement new estimation methods.

For natural gas pneumatic devices, pneumatic valves, pneumatic pumps, and atmospheric storage tanks located in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA is proposing that gathering and boosting reporters use the same methods for calculating emissions as in the Onshore Petroleum and Natural Gas Production segment. Where these emission sources are located within gathering and boosting facilities, these sources are likely to be similar to the ones located in the Onshore Petroleum and Natural Gas Production segment. Specifically, because most processing of the gas and oil extracted from wells will be processed downstream of the gathering and boosting facility, the equipment/activities in the Onshore Petroleum and Natural Gas Production segment will be designed to handle gas and oil of composition similar to the gas and oil in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, so the same methods are applicable and would be no more burdensome.

For blowdown vent stacks, the current subpart W requires reporting of emissions for the Onshore Natural Gas Processing segment, but not for the Onshore Petroleum and Natural Gas Production segment. The EPA is proposing that the same methods that are used for the Onshore Natural Gas Processing segment be applied to blowdowns of equipment in the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The same exemptions, including those for volumes less than 50 cubic feet and for desiccant dehydrator reloading, that are applied to the Onshore Natural Gas Processing segment should also be applied to the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The EPA expects that the exemption for volumes less than 50 cubic feet should alleviate any concerns with the burden of calculating emissions from small gathering pipelines.

Several emission sources, including compressors, acid gas removal units, dehydrators, flares, and equipment leaks are found in both the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment. For acid gas removal units, dehydrators, and flare stacks, the current subpart W specifies the same methods for these sources in both the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment. For acid gas removal units and dehydrators, the current rule includes several alternative methods, and the same alternative methods are specified for both segments. Because these emission sources in the Onshore Petroleum and Natural Gas Gathering and Boosting segment are likely to be similar to the ones in the Onshore Petroleum and Natural Gas Production segment or the Onshore Natural Gas

Processing segment, the same methods would be applicable.

For compressors and equipment leaks, subpart W contains one method in the Onshore Petroleum and Natural Gas Production segment and a different method for the same emission source in the Onshore Natural Gas Processing segment. We are proposing that the gathering and boosting reporters use the same method as in the Onshore Petroleum and Natural Gas Production segment. The method for the Onshore Petroleum and Natural Gas Production segment for compressors and equipment leaks relies on the reporter counting the number of compressors or components (*e.g.,* population counts) and then applying emission factors per compressor or component for that population. Alternatively, for equipment leaks, the reporter may count the number of pieces of major equipment, assume the default component counts in Table W–1B, and then apply emission factors per component. This proposed population count approach is appropriate for the Onshore Petroleum and Natural Gas Gathering and Boosting segment because, as in the Onshore Petroleum and Natural Gas Production segment, the equipment is often geographically dispersed and may be visited only intermittently. Under the proposed approach, a reporter would need to establish an inventory of the components or equipment subject to the population counts, apply the emission factors, and then update the inventory each year to account for new or retired components or equipment. The EPA also seeks comment on the appropriateness of the methods used in the Onshore Natural Gas Processing segment for compressors and equipment leaks, which are outlined in 40 CFR 98.234(a).

For gathering pipelines, the EPA is proposing to use an emission factor approach that is essentially the same as the approach used for equipment leaks in the Onshore Petroleum and Natural Gas Production segment. For gathering lines, reporters would use the population count and emission factor approach in 40 CFR 98.233(r). The emission factors that are being proposed, which would be added to an amended Table W–1A, are whole gas emission factors based on the U.S. GHG Inventory. The population count would be the miles of gathering pipeline, similar to the approach used for calculating emissions from natural gas distribution pipelines in the Natural Gas Distribution segment.

The EPA has determined that the proposed monitoring and reporting requirements minimize the potential confusion associated with calculating emissions from the Onshore Petroleum and Natural Gas Gathering and Boosting segment by adopting the same methods used for calculating emissions that are used in the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment. The EPA requests comment on whether the proposed monitoring and reporting requirements for the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment are appropriate for these emission sources, and if not, what methodologies would be more appropriate.

Data collected through the proposed reporting requirements for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in subpart W would improve the EPA's estimates and understanding of emissions from sources covered by the new segment and from the petroleum and natural gas sector. The improved data would provide a better understanding of sources in the petroleum and natural gas industry for which the public currently has little information. For example, the data that would be collected through these proposed revisions would inform updates to the U.S. GHG Inventory.

The proposed requirements would require the reporting of GHG emissions from an entire gathering and boosting facility instead of the partial approach that currently exists under the GHGRP. Specifically, some gathering and boosting emission sources, such as natural gas compression stations, are only required to report GHG emissions if the facility exceeds the 25,000 metric tons CO_2e annual emission reporting threshold in subpart A, 40 CFR 98.2(a)(2), based on combustion emissions that are reported under subpart C. Subpart W does currently require reporting from facilities that perform ''natural gas processing'' in 40 CFR 98.230(a)(3), but this requirement is only for those facilities that perform separation of natural gas liquids or non-methane gases from produced natural gas or the separation of natural gas liquids into one or more component mixtures and exceed 25 MMscfd annual average daily gas throughput. Subpart W also covers sources such as compressors, dehydration, or acid gas removal that are located on a single well-pad or associated with a single well as part of the Onshore Petroleum and Natural Gas Production segment. However, if these sources are associated with multiple well pads and not located on a single well-pad, they are not part of the Onshore Petroleum and Natural Gas Production segment and are currently not subject to reporting under subpart W.

The EPA is not proposing to alter the definitions for the Onshore Natural Gas Processing or Onshore Petroleum and Natural Gas Production segments within subpart W, found in 40 CFR 98.230, so if these amendments are finalized as proposed, then the facilities and emission sources that are currently in the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment of subpart W would remain in those segments. For facilities that have emissions sources that are covered by the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment of subpart W but do not collectively meet the threshold for reporting in those segments, those emission sources or equipment should only be considered in the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment if they meet the proposed definition of ''gathering and boosting system'' and the appropriate thresholds. However, the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment would increase the overall coverage of subpart W by including some facilities that are reporting under subpart C for combustion emissions but only have to report a subset of their emissions currently, or that are not reporting at all under the GHGRP. Under the proposed rule, these facilities would become part of the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment in subpart W. If a reporter has more than one facility currently reporting under subpart C and they are consolidated as part of a single gathering and boosting facility as defined in this proposal, then the gathering and boosting facility would begin reporting all their relevant facility emissions, including those previously reported under subpart C, as a single consolidated facility under subpart W. The consolidated reporting facility would also include the parts of the system, such as pipelines and smaller compression stations, for which emissions are not currently being reported.

The proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment would also include equipment and facilities that are not currently reporting under the GHGRP. For example, the EPA anticipates that the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment would include many compressor stations in gathering and boosting systems that are not currently reporting because they do not, as a facility defined in 40 CFR 98.6, exceed the 25,000 metric tons CO_2e per year reporting threshold in subpart A, 40 CFR 98.2(a)(2). However, when aggregated with the gathering pipelines and other compressor stations that are under common ownership and control within a system, the complete system may exceed the reporting threshold and would be required to begin reporting.

The EPA considered other reporting options for defining the facility and the level of reporting, but none of them would have achieved the same balance of geographically specific information and reduced industry burden as the proposed option. One option considered was using the definition of ''facility'' found in 40 CFR 98.6 that states, ''Facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.'' This would mean that each piece of property (or adjacent properties under common ownership or common control) with gathering and boosting equipment that exceeded the 25,000 metric tons CO_2e annual threshold would be considered its own ''facility''. This option provided limited data on the segment as a whole due to decreased coverage compared to other options, though more granular, site-specific data would likely be achievable for this option. This option would also require separate reports for each compressor station and/or gathering line, which would have resulted in a high reporting burden on owners/operators in this segment. Therefore, the EPA concluded that this option would not achieve the goals of having a thorough data set and transparent, complete information for this sector while minimizing burden to reporters. The EPA also considered an option that would have separated the gathering pipelines and gathering and boosting stations (*e.g.,* facilities with compressors, dehydration, and acid gas removal) into different segments. The gathering and boosting stations would have reported at the basin level, and the pipelines at the national level (*e.g.* all gathering pipelines owned by a person or entity within the United States). However, the EPA is not proposing this option because it would have potentially resulted in higher burden to reporters by requiring reporting of additional facilities under their ownership. The EPA is seeking comment on whether these options should be considered and how they might achieve transparent and complete data for this segment without imposing additional burden on reporters compared to the proposed option. For more information regarding the options considered for defining the facility, see ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule.''

C. Natural Gas Transmission Lines Between Compressor Stations

The EPA is proposing to add reporting requirements for emissions from natural gas transmission pipeline blowdowns between compressor stations in a new Onshore Natural Gas Transmission Pipeline segment. For purposes of the Onshore Natural Gas Transmission Pipeline segment, a blowdown is the release of gas from transmission pipelines for the purpose of reducing system pressure or complete depressurization. Transmission pipeline blowdowns occur when, a segment of pipeline is isolated from the rest of the line and the natural gas inside is purged through a blowdown vent stack. These blowdowns are needed to safely inspect and maintain the pipelines, but the purging of natural gas produces methane emissions that are currently not included in subpart W. In the U.S. GHG Inventory, the EPA estimated that there were over 300,000 miles of transmission pipelines in 2012, and the blowdown emissions associated with those pipelines were estimated to be 85,000 metric tons of methane a year. Although subpart W does require reporting of emissions from onshore natural gas transmission compression stations, it currently does not cover onshore natural gas transmission pipelines in between compressor stations. This represents a gap in the coverage of emission sources from the petroleum and natural gas systems source category covered by subpart W.

The EPA is proposing to define the onshore natural gas transmission pipeline owner or operator depending on whether the transmission pipeline is interstate or intrastate. For interstate pipelines, the onshore natural gas transmission pipeline owner or operator would be the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f. For intrastate pipelines, the onshore natural gas transmission pipeline owner or operator would be the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act (NGPA). The Certificate of Public Convenience and Necessity is a certificate issued by the Federal Energy Regulatory Commission (FERC) that allows the pipeline company to engage in the transportation and/or sale for resale of natural gas in interstate commerce or to acquire and operate facilities needed to accomplish this. The certificate is issued by FERC after FERC has approved the construction of a pipeline, and it allows the holder to build and operate the pipeline. Operators of intrastate pipelines are required to prepare a Statement of Operating Conditions for compliance under section 311 of the NGPA. Section 311 of the NGPA allows an interstate pipeline company to sell or transport gas on behalf of any intrastate pipeline or local distribution company without prior FERC approval.

The EPA is proposing that the facility for the new Onshore Natural Gas Transmission Pipeline segment would be defined as the total U.S. mileage of natural gas transmission pipelines owned or operated by an onshore natural gas transmission pipeline owner or operator. If an entity owned and operated multiple pipelines in the U.S., the facility would be considered the aggregate of those pipelines, even if they are not interconnected. In defining the facility, the EPA considered other options, such as the facility being the amount of pipeline owned and operated by an entity within a state or basin, or the facility being each separate pipeline. In considering these other options, the EPA had to take into account that many major pipeline systems are essentially linear systems to move gas from one part of the U.S. to another, and requiring reporters to file separate reports for each portion of the system in any one state or other defined geography would impose higher reporting burden on those subject to this source category without providing the EPA with additional, specific information. The EPA also took into account the fact that many entities own and operate pipeline segments that may not be directly interconnected, but are connected with pipelines owned and operated by other entities as part of the national network of natural gas transmission pipelines. The proposed approach limits the burden on reporters to correlate the pipeline ownership transfer points with specific geographical segments. Instead, the reporters can track the required information for their various pipelines, regardless of location, and submit data associated with all of them in one report.

The EPA is proposing that reporters would use the methods in 40 CFR 98.233(i) to calculate or measure emissions from pipeline blowdown events. One method allows a reporter to calculate emissions based on the volume of the pipeline segment between isolation valves that is blown down and the pressure and temperature of the gas within the pipeline. This method uses information that should be readily available to the reporter (*e.g.,* pipeline length, diameter, and operating pressure) and so should not be overly burdensome. The second method allows the reporter to measure the emissions from the blowdown using a flow meter on the blowdown vent stack. In both methods, the reporter would calculate both methane and carbon dioxide (CO_2) emissions from the volume of natural gas vented using either default gas composition or engineering estimates of composition as specified in 40 CFR 98.233(u)(2)(iii). In addition to the total annual emissions of methane and CO_2, natural gas transmission pipeline reporters would also report the methane and CO_2 emissions and location of each blowdown event.

The EPA previously considered fugitive emissions that result from leaks in transmission pipelines in the re-proposal of subpart W in April 2010 (75 FR 18616, April 12, 2010), but did not include provisions for these emissions in either the proposed or final rules. The April 2010 preamble explained that the EPA did not propose reporting requirements for fugitive emissions from leaks in natural gas pipeline segments between compressor stations due to the dispersed nature of the fugitive emissions, and the fact that, once fugitives are found, the leaks causing the emissions are usually addressed quickly for safety reasons (75 FR 18616, April 12, 2010). The EPA also notes that larger fugitive leaks are currently reported to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration as part of 49 CFR 191.3. Under this provision, any pipeline incident that results in unintentional gas loss of three million cubic feet or more must be reported. Therefore, the EPA is not proposing to include reporting requirements for fugitive emissions from transmission pipeline leaks.

The EPA also considered adding blowdowns between compressor stations on natural gas transmission pipelines to the Onshore Natural Gas Transmission Compression segment, which is already a reporting segment under subpart W, instead of creating a new segment. However, the Onshore Natural Gas Transmission Compression segment currently uses the same definition of facility as found in 40 CFR 98.6 and the natural gas transmission pipelines that surround a compressor station might not be compatible with that definition of ''facility'' because they would likely not be under common ownership or control with the adjacent compressor station(s). Therefore, keeping the definition of facility found in 40 CFR 98.6 for this proposed new segment would result in a higher reporting burden on pipeline owners/operators with a number of non-contiguous pipelines in the U.S. compared to the proposed option, because these owners/operators would have to submit individual reports for each pipeline they owned or operated. The proposed option simplifies reporting for this source by allowing each owner/operator to submit one report for all their transmission pipelines.

D. Well Identification Numbers

The EPA is proposing to amend 40 CFR 98.236 to add reporting requirements for well identification numbers to improve data quality by enabling identification of wells. If finalized, these reporting requirements would be reported for the first time in the report covering the year in which the rule is made effective (*e.g.,* if the final rule is effective January 1, 2016, then the reports covering 2016 data would be the first to include well identification numbers). Reporting of well identification numbers for previous years (*e.g.,* 2012) is not being proposed by the EPA. For the majority of wells, the well identification number reported will be the US Well Number (formerly referred to as the API Well Number, or API Number).[6] For any well that does not already have a US Well Number, the reporter would be required to provide the unique well number assigned by the permitting authority for drilling of oil and gas wells. US Well Numbers are required for wells in almost all states covered in the Onshore Petroleum and Natural Gas Production segment and are generally reported in relevant onshore production permitting documentation. This would allow the EPA to link the GHGRP data to other databases to more easily match the data reported under the GHGRP with other data sources and will improve the accuracy and transparency of subpart W. Being able to match the GHGRP data to other data sources would provide the EPA with more options for analysis of the GHGRP data to better inform future policy decisions related to GHG emissions from the oil and natural gas production sector. The reporting of the well identification numbers would also allow the EPA to assess the completeness and representativeness of the data collected under the GHGRP as a portion of all activity in the oil and natural gas production sector.

Since 1966, almost all U.S. oil and gas wells have been assigned a unique and permanent API Well Number in accordance with American Petroleum Institute (API)'s specification in Bulletin D12A.[7] The API Well Number was established to allow regulators to track drilling permits, collect royalties, and optimize field conservation. API transferred ownership of the well numbering specification to the Professional Petroleum Data Management (PPDM) Association in 2010. The PPDM Association issued an updated specification in May 2013 and then renamed the identifier as the US Well Number in June 2014.[8] The PPDM Association is working with state regulatory agencies to implement the 2013 updates, but adoption is at the discretion of the agency. State agencies that elect not to use the US Well Number have assigned unique well identification numbers to the gas and oil wells in that state for tracking in their regulatory databases. US Well Numbers and other well identification numbers are publically available, but the accessibility of the data varies from state to state. Reporters in the Onshore Petroleum and Natural Gas Production segment already track and maintain records by well identification number for other regulatory and reporting purposes.

The EPA is proposing to require the reporting of well identification numbers for the Onshore Petroleum and Natural Gas Production segment in two general cases. First, the EPA proposes to require reporters in the Onshore Petroleum and

[6] The Professional Petroleum Data Management Association. *The US Well Number Standard: An Identifier for Petroleum Industry Wells in the USA.* Version 2013 rev 1, published June 19, 2014. Available at *http://dl.ppdm.org/dl/1147.*

[7] American Petroleum Institute. *The API Well Number and Standard State And County Numeric Codes Including Offshore Waters.* API Bulletin D12A, January 1979. Available at *http://wellidentification.org/dl/US_API_Bulliten_1979.pdf.*

[8] The Professional Petroleum Data Management Association. *The US Well Number Standard: An Identifier for Petroleum Industry Wells in the USA.* Version 2013 rev 1, published June 19, 2014. Available at *http://dl.ppdm.org/dl/1147.*

Natural Gas Production segment to report a list of well identification numbers associated with different emission sources for all wells in a sub-basin included in the reported emissions data. Reporting the well identification numbers associated with different emission sources for each sub-basin would allow the EPA to determine completeness of reporting by evaluating the coverage of current reporting requirements and identifying potential cases of under-reporting by comparing lists of reported well identification numbers to lists of well identification numbers from state agencies. The EPA expects that this would present a low burden to reporters because reporters should already track and maintain well identification numbers. The EPA expects that most reporters track and maintain sub-basins for each well identification number. If a reporter does not, they can use the state code and county code portions of the US Well Number to identify the sub-basin.

Second, for reporters in the Onshore Petroleum and Natural Gas Production segment that report emissions using input data that are calculated from measurements at individual wells or equipment associated with individual wells (*e.g.,* if Equation W–10A was used to calculate emissions from oil well completions and workovers with hydraulic fracturing, well testing emissions), the EPA proposes to require the reporter to report the well identification number for which those measurements were made, or for which the equipment is associated. Reporting the well identification numbers for input data based on measurements at a sample of wells would allow the EPA to compare GHGRP data to data from other wells in the same basin or sub-basin to evaluate whether the measurements were likely representative of all wells in the basin or sub-basin. The EPA expects that this would present a low burden to reporters because reporters should already track and maintain well identification numbers associated with measurements used for the GHGRP input data.

Where emissions are reported for equipment that is on or associated with a single well pad, (*e.g.,* dehydrators, acid gas removal units), providing the well identification number(s) for the associated well(s) would also allow the EPA to compare the data that are used as inputs for estimating emissions to the data available from the well(s) to verify those data. The EPA expects that this would also present a low burden to reporters because reporters already have to make a determination of whether the equipment is on or associated with a single well pad, and would simply need to note and maintain the well identification number(s) for that associated piece of equipment.

E. Advanced Innovative Monitoring Methods

As oil and gas operations seek to capitalize on advances in measurement and monitoring technology in optimizing process operations and reducing fugitive emissions from process equipment leaks, opportunities will arise for facilities to use innovative technologies to gather real-time, continuous emissions data from area and point sources. For example, optical remote sensing techniques have existed for many years but recent technological advances have allowed these devices to be used in the field (*e.g.,* for fence line monitoring) to provide reliable measurements of gas concentrations, including methane, in the ambient air at the relevant detection limits.[9] [10]

The EPA is assessing the potential opportunities for applying remote sensing technologies and other innovations in measurement or monitoring technology to identifying and calculating emissions from affected sources under subpart W. The EPA's objective for this assessment is to determine if new and innovative technologies could be applied to the GHGRP to improve the overall accuracy and transparency of reported data in a cost-effective way while still meeting the overall objectives of Part 98. While the EPA is not proposing to incorporate these technologies into subpart W in this action, the EPA is requesting comment on the feasibility, possible regulatory approaches, provisions necessary to incorporate or allow the use of advanced measurement or monitoring methods in subpart W, and methods to ensure compliance with those provisions in an efficient manner. In particular, the EPA is soliciting data and case studies that could provide information regarding the benefits, costs, and potential problem areas, including consistency among reporters and the feasibility of verifying emissions, associated with using advanced innovative monitoring methods for providing emissions measurements in the oil and natural gas sector, including the provision of real-time or continuous measurements.

[9] Allen, D.T. et al. Measurements of methane emissions at natural gas production sites in the United States, *Proceedings of the National Academy of Sciences of the United States of America,* 110(44): 17768–17773, 2013.

[10] EPA Handbook: Optical Remote Sensing for Measurement and Monitoring of Emissions Flux, *http://www.epa.gov/ttnemc01/guidlnd/gd-052.pdf.*

Additionally, we are seeking comment on the EPA's memorandum on alternative and innovative measurement or monitoring technologies (see ''Discussion Paper on Potential Implementation of Alternative Monitoring under the GHGRP'' in Docket ID No. EPA–HQ–OAR–2014–0831). Following review of the data and information received in comments, the EPA may propose amendments related to the use of innovative technologies in reporting to the GHGRP in a future rulemaking.

F. Best Available Monitoring Methods

The EPA is proposing that facilities will be allowed to use BAMM for the proposed amendments for the 2016 reporting year for only the new industry segments and emission sources included in this proposal. These include calculating and reporting emissions from oil well completions and workovers with hydraulic fracturing, from onshore petroleum and natural gas gathering and boosting systems, and for transmission pipeline blowdown emissions. This proposal would allow reporters to use best available methods to estimate inputs to emission equations for the newly proposed emission sources using their best engineering judgment for cases where the monitoring of these inputs would not be possible beginning on January 1, 2016. The EPA is not proposing to allow the use of BAMM for the proposed reporting of well identification numbers because reporters should already have well identification numbers readily available for all wells and associated equipment to which this proposed reporting requirement would apply.

These reporters have the option of using BAMM from January 1, 2016, to March 31, 2016, without seeking prior EPA approval for certain parameters that cannot reasonably be measured according to the monitoring and QA/QC requirements of 40 CFR 98.234. Reporters would also have the opportunity to request an extension for the use of BAMM beyond March 31, 2016; those owners or operators would submit a request to the Administrator by January 31, 2016. This additional time for reporters to comply with the monitoring methods for new emission sources in subpart W would allow facilities to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions.

The EPA is not proposing to allow the use of BAMM beyond 2016 and does not anticipate that BAMM would be needed beyond 2016 for the new segments and emissions sources being proposed in this rule.

III. Proposed Confidentiality Determinations

A. Overview and Background

In this proposed rule, we are proposing confidentiality determinations for 171 data elements proposed to be reported by the following segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. These data elements include new reporting requirements for existing sources already reporting under subpart W as well as new reporting requirements that would be reported by additional industry segments or sources under these proposed amendments.

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; 79 FR 63750, October 24, 2014. 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

With the exception of the specific data elements addressed in Section III.D of this preamble, 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'' (hereafter 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.[11] 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) in the 2011 Final CBI Rule. However, the EPA has since proposed and finalized an approach for addressing disclosure concerns associated with inputs to emissions equations.[12]

For this rulemaking, we are proposing to assign 165 new 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 data element. For the proposed categorical assignment of the data elements in these eight categories with categorical determinations, see the memorandum ''Data Category Assignments and Confidentiality Determinations for All Data Elements (excluding inputs to emission equations) in the Proposed '2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems' '' in Docket ID No. EPA–HQ–OAR–2014–0831.

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 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 the memorandum ''Data Category Assignments and Confidentiality Determinations for All Data Elements (excluding inputs to emission equations) in the Proposed '2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems' '' in Docket ID No. EPA–HQ–OAR–2014–0831. For the results of our case-by-case evaluation of these data elements, see Sections III.C and III.D of this preamble.

In addition to the individual data element determinations described above and for the reasons stated below, we are proposing individual confidentiality determinations for six new 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

[11] 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,'' and ''Data Elements Reported for Periods of Missing Data that are not Inputs to Emission Equations.''

[12] Revisions to Reporting and Recordkeeping Requirements, and Confidentiality Determinations Under the Greenhouse Gas Reporting Program; Final Rule. (79 FR 63750, October 24, 2014).

categories.[13] Similarly, while the six proposed new 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 six 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 six data elements; accordingly, these data elements should not be assigned to these data categories. Not assigning these six 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 six 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 CAA. 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 six proposed subpart W data elements, see Section III.D of this preamble.

We are also proposing to assign 65 additional data elements used to calculate GHG emissions in subpart W for the Onshore Petroleum and Natural Gas Gathering and Boosting segment, Onshore Natural Gas Transmission Pipeline segment, and for emissions from oil wells with hydraulic fracturing to the ''Input to Emission Equation'' data category. We are not proposing a confidentiality determination for this data category. The majority of these data elements are existing data elements in subpart W that would be applied to the new Onshore Petroleum and Natural Gas Gathering and Boosting segment and Onshore Natural Gas Transmission Pipeline segment. Some of the data elements are new data elements that are used as inputs to proposed Equation W–12C. 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.[14] 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.[15] We performed a similar evaluation for the 67 subpart W inputs to emission equations when they are applied to the Onshore Petroleum and Natural Gas Gathering and Boosting segment, Onshore Natural Gas Transmission Pipeline segment, and for calculating emissions from oil wells with hydraulic fracturing.

For the Onshore Natural Gas Transmission Pipeline segment, the EPA did not identify any potential disclosure concerns with the data elements that are inputs to emissions equations. Accordingly, the proposal would require reporting of these data elements by March 31, 2017, which is the reporting deadline for the 2016 reporting year.

For calculating emissions from oil wells with hydraulic fracturing, the EPA did not identify any disclosure concerns, except when the oil wells to which those inputs to emission equations apply meet the definition of either ''wildcat well'' or ''delineation well.'' ''Delineation well'' is defined as ''a well drilled in order to determine the boundary of a field or producing reservoir.'' ''Wildcat well'' is defined as ''a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.'' As noted in a previous rulemaking (79 FR 63750, October 24, 2014), the early public disclosure of certain data elements that are inputs for these two specific well definitions could reveal data on well productivity that could give competitors an advantage by giving them information on new fields or new areas of existing fields without having to drill their own wildcat or delineation wells. This could result in the loss of investment value for certain reporters. For wildcat and delineation wells, the EPA is proposing to allow reporters to delay reporting of these data elements for 2 years, as currently allowed for gas wells with hydraulic fracturing that meet the definition of either ''wildcat well'' or ''delineation well'', because a 2-year delay of reporting is sufficient to prevent early public disclosure of these data and will provide sufficient time for a reporter to thoroughly conduct an assessment of the well. The specific proposed data elements impacted are: (1) The cumulative gas flowback time, in hours, for each sub-basin, from when gas is first detected until sufficient quantities are present to enable separation (§ 98.236(g)(5)(i)); (2) the cumulative flowback time, in hours, for each sub-basin, after sufficient quantities of gas are present to enable separation (§ 98.236(g)(5)(i)); (3) the measured flowback rate, in standard cubic feet per hour, for each sub-basin (§ 98.236(g)(5)(ii)); and (4) the total annual gas-liquid separator oil volume that is sent to applicable onshore storage tanks, in barrels (§ 98.236(j)(1)(v)).

In addition to the data elements that are inputs to emission equations for wildcat and delineation wells, the EPA has further determined that one other proposed data element related to these two specific types of wells may have early disclosure concerns due to the reasons stated above. Therefore, in order to treat all early disclosure concerns related to exploratory wells consistently throughout subpart W, the EPA is proposing to allow reporters to delay reporting for this data element for 2 years as well. The EPA is also proposing a confidentiality determination for this data element, found in Table 3 of this

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

[14] 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).

[15] 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).

preamble, which would apply once the data element is reported to the EPA following the 2-year delay. The specific proposed data element impacted is: The total annual oil throughput that is sent to all atmospheric tanks, in barrels (§ 98.236(j)(2)(i)(A)). Other data elements related to delineation or wildcat wells that are not proposed to be amended in this action have been addressed in a previous rulemaking (79 FR 70352, November 25, 2014).

For calculating emissions from sources in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA did not identify any disclosure concerns. The Onshore Petroleum and Natural Gas Gathering and Boosting segment would be a regionally concentrated segment, with gathering lines and other services located in fixed geological basins. Because of the amount of fixed assets required to operate in this segment (*e.g.,* gathering lines and boosting stations), companies operating in this segment enter into long term agreements with natural gas producers to gather natural gas and transport it to natural gas processing facilities or, in some cases, transmission pipelines. These agreements are for long periods, lasting from several years to the life of the lease for the producing wells, and establish the prices for gathering services for the life of the agreement. Once these agreements are established, information that would be revealed from the ''inputs to emissions equations'' is not likely to affect the competitive position of the company operating the gathering and boosting system because it will not reveal information about the cost or profitability of providing that gathering service, or about the company's ability to enter into new agreements and expand operations. As a result, the ''inputs to equations'' data elements in this segment would not be likely to reveal any proprietary information about the facility or cost to do business.

For the list of new subpart W inputs to emission equations and the results of our evaluation, see the memorandum, ''Review for Potential Disclosure Concerns for Inputs to Emission Equations Affected by the Proposed '2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems' '' in Docket ID No. EPA–HQ–OAR–2014–0831.

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 that 36 data elements for subpart W that have been assigned 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 would be reported for sources in the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment, the Onshore Natural Gas Transmission Pipeline segment, or for onshore natural petroleum and natural gas production facilities that report emissions from oil wells with hydraulic fracturing. The data elements were assigned to these two categories in earlier EPA actions (77 FR 48072, August 13, 2012; and 79 FR 70352, November 25, 2014). We are proposing confidentiality determinations for these data elements when applied to these new emission sources 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 EPA concluded that the proposed new 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 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, the proposed confidentiality determination for each data element, and our rationale for each determination as they would apply to the Onshore Petroleum and Natural Gas Gathering and Boosting segment or for oil wells with hydraulic fracturing in the Onshore Petroleum and Natural Gas Production segment.

For the existing data elements previously 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'' that would be reported by the newly proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment, the Onshore Natural Gas Transmission Pipeline segment, or for oil wells with hydraulic fracturing, we are proposing confidentiality determinations based on a new case-by-case evaluation of the data elements, taking into consideration the characteristics of the new reporters that would be required to report these data elements by the proposed amendments. Because these data elements do not meet the definition of emissions data in 40 CFR 2.301(a), the EPA used the 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 by data category, the proposed confidentiality determination for each data element, and our rationale for each determination.

Table 2. Proposed Confidentiality for 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)(v)	Whether any CO_2 emissions from the acid gas removal unit are recovered and transferred outside the facility.	This proposed data element would be reported by onshore petroleum and natural gas gathering and boosting facilities. 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 CO_2 and hydrogen sulfide from raw natural gas streams and are commonly found at compressor stations in gathering and boosting systems, and at natural 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."
98.236(e)(1)(xvi)	Whether any dehydrator emissions are vented to a vapor recovery device.	These proposed data elements would be reported by onshore petroleum and natural gas gathering and boosting facilities. 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 and are commonly found at compressor stations in gathering and boosting systems, and at natural gas processing facilities. 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 onshore petroleum and natural gas gathering and boosting facilities.
98.236(e)(1)(xvii)	Whether any dehydrator emissions are vented to a flare or regenerator firebox/fire tubes.	
98.236(e)(1)(xviii)	For each glycol dehydrator with an annual average daily natural gas throughput greater than or equal to 0.4 MMscfd, whether any dehydrator emissions are vented to the atmosphere without being routed to a flare or regenerator firebox/fire tubes.	
98.236(e)(2)(iii)	For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscfd, whether any the total number of dehydrators were venting to a vapor recovery device.	
98.236(e)(2)(iv)	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	

Citation	Data Element	Proposed Confidentiality Determination and Rationale
	recovery device or a flare or regenerator firebox/fire tubes.	
98.236(c)(2)(v)	For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 MMscfd, whether any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes.	
98.236(e)(2)(v)(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, the total number of dehydrators venting to a vapor recovery device.	
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 and vent to a flare or regenerator firebox, the total number of dehydrators.	
98.236(e)(3)(i)	For dehydrators that use desiccant and vent to a flare or regenerator firebox, the total number of dehydrators.	
98.236(g)	Whether the facility had any oil 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 oil 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 and the cumulative flowback time. Information on the number of completions and workovers performed by an oil and gas operator in a given year and the
98.236(g)(3)	For each oil well completion or workover and well type combination, the total number of completions or workovers with hydraulic fracturing.	
98.236(g)(5)(i)	If you used Equation W-10A to calculate annual volumetric total gas emissions for multiple wells,	

Citation	Data Element	Proposed Confidentiality Determination and Rationale
	the cumulative gas flowback time, in hours, for each sub-basin, from when gas is first detected until sufficient quantities are present to enable separation ("$T_{p,i}$" in Equation W-10A).	age and production rates for wells can be derived from or is available publicly on state oil and gas commission Web sites. Information on the flowback time would be aggregated across multiple oil wells in a sub-basin. 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)(5)(i)	If you used Equation W-10A to calculate annual volumetric total gas emissions for multiple wells, the cumulative flowback time, in hours, for each sub-basin, after sufficient quantities of gas are present to enable separation ("$T_{p,s}$" in Equation W-10A).	
98.236(i)(1)(i)	If you calculated emissions from blowdown vent stacks by equipment or event type, the total number of blowdowns in the calendar year for the equipment or event type (the sum of equation variable "N" from Equation W-14A or Equation W-14B of this subpart, for all unique physical volumes for the equipment or event type).	This proposed data element would be reported by onshore petroleum and natural gas gathering and boosting facilities and natural gas transmission pipeline 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, onshore petroleum and natural gas gathering and boosting facilities and natural gas transmission pipeline 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."
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 gathering and boosting facilities and provide information on malfunctioning of dump valves on gas-liquid separators.

Citation	Data Element	Proposed Confidentiality Determination and Rationale
98.236(j)(3)(i)	If any of the gas-liquid separator liquid dump valves did not close properly during the reporting year, the total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.	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, release of 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 dump valves on multiple gas-liquid separators in a sub-basin did not close properly, the total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of "T_n" in Equation W-16).	
98.236(z)(2)(iii)	Type of fuel combusted.	This data element would be reported by onshore petroleum and natural gas gathering and boosting facilities. This data element would provide information on the types of fuel burned. However, facilities in this segment 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 typically available in a facility's construction and operating permits. For these reasons, we consider that release of information on the types of fuels burned by onshore petroleum and natural gas gathering and boosting facilities would not be likely to cause substantive competitive harm and propose this data element be designated as "not CBI" for this industry segment.
98.236(aa)(11)(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.	These proposed data elements would be reported by natural gas transmission pipeline companies, which are regionally concentrated and have control over particular segments of the pipeline infrastructure. Existing pipeline construction and natural gas transmission technology and operations development information is generally well-known and understood. It is possible that the limited number of firms and the regional concentration could pose potential data sensitivity issues. Firms in the natural gas transmission pipeline segment compete with others in their region for shipments of natural gas. Even though there may be only one pipeline transmitting natural gas from one
98.236(aa)(11)(ii)	The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.	
98.236(aa)(11)(iii)	The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.	

Citation	Data Element	Proposed Confidentiality Determination and Rationale
98.236(aa)(11)(iv)	The quantity of natural gas transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.	location to another, competition exists between firms that wish to accept shipments of natural gas within a given region, for potential transmission to different endpoints. Such firms could make use of information about their competitors' throughput quantity and/or cost structure to strategically set their prices or other contract terms. Even though the market is regulated by FERC, actual contract prices may be set at levels below the FERC-mandated maximum tariff. However, the information proposed to be collected is aggregated to the nationwide level, and small pipeline operations are unlikely to report as they are not expected to exceed the reporting threshold. In addition, these data elements are also reported to the Energy Information Administration (EIA) (e.g., natural gas withdrawn from storage, natural gas stored, gas received at city gate), and the 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)(11)(v)	The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.	
"Unit/Process 'Static' Characteristics That Are Not Inputs to Emission Equations" Data Category		
98.236(j)(1)(xi)	If using Calculation Method 1 or 2, the number of wells sending oil to gas-liquid separators or directly to atmospheric tanks.	These data elements would be reported by onshore petroleum and natural gas gathering and boosting facilities. Separators are used to separate hydrocarbons into liquid and gas phases. Separators are typically connected to atmospheric storage tanks (hydrocarbon tanks) where hydrocarbon liquids are stored. The number of well-head separators sending oil to atmospheric tanks can vary widely depending on numerous conditions, including the sizing of the tank and throughput of the separators, and the number of parties involved with handling or processing the separated constituents. Information on the count of atmospheric storage tanks with a throughput above 500 barrels of oil per day is already publicly available in title V permits under the EPA's National Emission Standards for Hazardous Air Pollutants (NESHAP) for Oil and Gas Production (40 CFR part 63, subpart HH). Any additional information required under subpart W regarding the number of
98.236(j)(1)(xii)	If using Calculation Method 1 or 2, the number of atmospheric tanks.	
98.236(j)(1)(xiv)(A)	If using Calculation Method 1 or 2, if any emissions from the atmospheric tanks at your facility were controlled with vapor recovery systems, the number of atmospheric tanks that control emissions with vapor recovery systems.	
98.236(j)(1)(xvi)(A)	If using Calculation Method 1 or 2, if you controlled emissions from any atmospheric tanks at your facility with one or more flares, the number of atmospheric tanks that controlled emissions with flares.	

Citation	Data Element	Proposed Confidentiality Determination and Rationale
98.236(j)(2)(i)(D)	If using Calculation Method 3, the number of atmospheric tanks in the basin.	wellhead separators is the same type of information already made publicly available through the NESHAP and thus is a reasonable expansion of that information. Further, information about the number of well-head separators sending oil to atmospheric tanks does not provide insight into the performance (ability to separate hydrocarbon into different phases) or the overall operational efficiency for the facility that could cause substantial competitive harm if disclosed. We propose that these data elements be designated as "not CBI."
98.236(j)(2)(ii)(B)	If using Calculation Method 3, the number of atmospheric tanks in the sub-basin that did not control emissions with flares, including those that have vapor recovery.	
98.236(j)(2)(iii)(B)	If using Calculation Method 3, the number of atmospheric tanks in the sub-basin that controlled emissions with flares.	
98.236(z)(1)(ii)	For each combustion unit type listed in §§ 98.236(z)(1), the total number of combustion units.	This data element would be reported by onshore petroleum and natural gas gathering and boosting facilities. This data element provides information on the number of internal and external combustion units located at these facilities. However, this information would not be likely to cause substantial competitive harm if released to the public, because internal and external combustion units are typical parts of an onshore petroleum and natural gas gathering and boosting facility and the total number of such units is not considered to be competitively sensitive information by this industry segment. Because disclosure of the number of combustion units would not be likely to cause substantive competitive harm to this segment, we propose this data element be designated as "not CBI" when reported by onshore petroleum and natural gas gathering and boosting facilities.
98.236(aa)(11)(vi)	The miles of transmission pipeline in the facility.	This proposed data element would be reported by natural gas transmission pipeline companies, which are regionally concentrated and have control over particular segments of the pipeline infrastructure. Existing pipeline construction and natural gas transmission technology and operations development information is generally well-known and understood. It is possible that the limited number of firms and the regional concentration could pose potential data sensitivity issues. Firms in the natural gas transmission pipeline segment compete with others in their region for shipments of natural

Citation	Data Element	Proposed Confidentiality Determination and Rationale
		gas. Even though there may be only one pipeline transmitting natural gas from one location to another, competition exists between firms that wish to accept shipments of natural gas within a given region, for potential transmission to different endpoints. Such firms could make use of information about their competitors' throughput quantity and/or cost structure to strategically set their prices or other contract terms. Even though the market is regulated by FERC, actual contract prices may be set at levels below the FERC-mandated maximum tariff. However, the information proposed to be collected is aggregated to the nationwide level, and small pipeline operations are unlikely to report as they are not expected to exceed the reporting threshold. In addition, each company must provide a map of the entire system to FERC and on the company Web site (18 CFR 284.12), and the total mileage of the system can be determined from these publically-available maps. 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."

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

The proposed revision includes six data elements that are production and/or throughput data from subpart W facilities that would be newly reported for the Onshore Petroleum and Natural Gas Gathering and Boosting segment. 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 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. The proposed results of these individual determinations are presented in Table 3 of this preamble.

As described 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 six 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 were 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 six 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 their publication would be likely to cause competitive harm.

For the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA is proposing that five data elements related to the throughput of each gathering and boosting facility be reported and one data element related to the amount of produced gas consumed by the facility be reported. These data elements are not publicly available for all facilities operating in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, although they are publicly available for facilities in the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment.[16] However, information for

[16] See the rationale for determining that similar data elements are not CBI for the onshore petroleum and natural gas production segment and the natural gas processing segment in the November 25, 2014 preamble (79 FR 70352).

some gathering and boosting systems is available on the company Web site or in annual reports. In addition, even if the data are not available, companies operating in this segment enter into long term agreements with natural gas producers to gather natural gas. Once these agreements are established, information that would be revealed from the data elements in Table 3 is not likely to affect the competitive position of the company operating the gathering and boosting system because it will not reveal information about the cost or profitability of providing that gathering service, or about the company's ability to enter into new agreements and expand operations. In addition, the information will be aggregated to the basin or sub-basin level rather than being reported for individual gathering and boosting systems. Therefore, we propose that these data, when reported by the newly proposed onshore petroleum and natural gas gathering and boosting reporters, be designated as not CBI because their disclosure would not be likely to cause competitive harm to reporters in that industry segment. This proposed determination does not affect earlier determinations made for reporters of the same data elements in other industry segments.

Table 3. Proposed Individual Confidentiality Determination for New Data Elements

Citation	Data Element	Proposed Confidentiality Determination and Rationale
Onshore Petroleum and Natural Gas Gathering and Boosting		
98.236(j)(2)(i)(A)	If using Calculation Method 3, the total annual oil/condensate throughput that is sent to all atmospheric tanks in the gathering and boosting facility, in barrels.	We propose that each of these data elements be designated as "not CBI." The Onshore Petroleum and Natural Gas Gathering and Boosting segment is a regionally concentrated segment, with gathering lines and other services located in fixed geological basins. Because of the amount of fixed assets required to operate in this segment (e.g., gathering lines and boosting stations), companies operating in this segment enter into long term agreements with natural gas producers to gather natural gas and transport it to natural gas processing facilities or, in some cases, transmission pipelines. These agreements are for long periods, lasting from several years to the life of the lease for the producing wells, and establish the prices for gathering services for the life of the agreement. Once these agreements are established, information on the actual throughput of the gathering and boosting system is not likely to affect the competitive position of the company operating the gathering and boosting system because it will not reveal information about the cost or profitability of providing that gathering service, or about the company's ability to enter into new agreements and expand operations. Data on the length, diameter, and pressure of gathering lines, and on the size (e.g., horsepower) of gathering compression stations is typically publicly available through construction and operating permits for these sources. These data can be used to determine the capacity of these systems, if it is not already reported elsewhere. Actual throughput of gathering and boosting systems, in terms of annual average daily throughput, is frequently included in the quarterly or annual reports for publicly traded companies and these are readily available on company Web sites. Annual throughput capacity and actual throughput is often also listed on gathering company Web sites. Based on the general availability of the actual throughput information, and the absence of an adverse competitive effect from revealing this information, the EPA is proposing that these data elements be considered "not CBI."
98.236(aa)(10)(i)	The quantity of produced gas throughput in the calendar year, in thousand standard cubic feet.	
98.236(aa)(10)(ii)	The quantity of produced gas consumed by the facility in the calendar year, in thousand standard cubic feet.	
98.236(aa)(10)(iii)	The quantity of produced condensate throughput in the calendar year, in barrels.	
98.236(aa)(10)(iv)	The quantity of produced oil throughput in the calendar year, in barrels.	
98.236(aa)(10)(v)	The quantity of gas flared, vented and/or unaccounted for in the calendar year, in thousand standard cubic feet.	

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 new data elements assigned to categories with such determinations. If a commenter believes that the EPA has improperly assigned certain new 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: 26 data elements assigned to the ''Unit/Process Operating Characteristics That Are Not Inputs to Emission Equations'' data category; 10 data elements assigned to the ''Unit/Process 'Static' Characteristics That Are Not Inputs to Emission Equations'' category; and six data elements for which no data category assignment was proposed.

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 the data elements identified in this rulemaking. 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

A. Costs of the Proposed Amendments

As discussed in Section II of this preamble, the EPA is proposing amendments to subpart W that would add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline.

Reporters in the Onshore Petroleum and Natural Gas Production segment would have to monitor and report emissions and data elements associated with oil well completions and workovers with hydraulic fracturing. Reporters in this segment would also have to report the well identification numbers associated with individual oil and gas wells, and when reporting emissions for certain pieces of equipment, such as acid gas removal units, dehydrators, tanks, and flares, that are associated with individual oil and gas wells. The addition of the requirement to report emissions associated with oil well completions and workovers with hydraulic fracturing is expected to cause an increase in the amount of emissions that would count towards determining applicability with subpart W. The proposed addition of reporting requirements for oil wells with hydraulic fracturing is expected to affect 246 existing reporters and to cause approximately 50 new reporters to exceed the reporting threshold for the onshore petroleum and natural gas production facility.

Reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment would need to estimate and report emissions data and related data elements associated with several different emission sources within this newly proposed industry segment. Approximately 200 new reporters are expected to be subject to subpart W due to the proposed amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in this rulemaking.

Reporters in the Onshore Natural Gas Transmission Pipeline segment would need to estimate and report emissions data and related data elements associated with transmission pipeline blowdown activities. Approximately 150 new reporters are expected to be subject to subpart W due to the proposed amendments in this rulemaking.

The proposed amendments to subpart W are not expected to significantly increase burden. See the memorandum, ''Assessment of Impacts of the 2015 Proposed Revisions to Subpart W'' in Docket ID No. EPA–HQ–OAR–2014–0831 for additional information.

B. Impacts of the Proposed Amendments on Small Businesses

As required by the Regulatory Flexibility Act (RFA) and Small Business Regulatory Enforcement and Fairness Act (SBREFA), the EPA assessed the potential impacts of these amendments on small entities (small businesses, governments, and non-profit organizations). (See Section V.C of this preamble for definitions of small entities.)

The EPA conducted a screening assessment comparing compliance costs to onshore petroleum and natural gas production specific receipts data for establishments owned by small businesses. This ratio constitutes a ''sales'' test that computes the annualized compliance costs of this rule as a percentage of sales and determines whether the ratio exceeds 1 percent.[17] The cost-to-sales ratios were constructed at the establishment level (average reporting program costs per establishment/average establishment receipts) for several business size ranges. This allowed the EPA to account for receipt differences between establishments owned by large and small businesses and differences in small business definitions across affected industries. The results of the screening assessment are shown in Table 4 of this preamble.

TABLE 4—ESTIMATED COST-TO-SALES RATIOS FOR FIRST YEAR COSTS BY INDUSTRY AND ENTERPRISE SIZE [A]

Industry segment	NAICS	NAICS description	SBA size standard (effective January 22, 2014)	Average cost per entity ($1,000/entity)	All enterprises (percent)	Owned by enterprises with: <20 employees [b] (percent)	20 to 99 employees (percent)	100 to 499 employees (percent)	<500 employees (percent)	500 to 999 employees (percent)	1,000 to 2,499 employees
Onshore Petroleum and Natural Gas Production.	211	Oil and Gas Extraction.	500 employees	$29.36	0.07	0.43	0.03	0.01	0.09	0.00	0.00
	213111	Drilling Oil and Gas Wells.	500 employees	29.36	0.28	1.00	0.32	0.06	0.19	0.02	0.01
	213112	Support Activities for Oil and Gas Operations.	$35.5 million	29.36	0.45	1.24	0.39	0.08	0.33	0.02	NA
	221	Utilities	500 employees	29.36	0.08	0.84	0.14	0.06	0.19	0.04	NA
	486	Pipeline Transportation.	$25.5 million	29.36	0.29	0.44	0.18	0.26	0.26	0.33	NA
Onshore Natural Gas Transmission Pipeline.	211	Oil and Gas Extraction.	500 employees	3.19	0.01	0.05	0.00	0.00	0.01	0.00	0.00
	213111	Drilling Oil and Gas Wells.	500 employees	3.19	0.03	0.11	0.03	0.01	0.02	0.00	0.00
	213112	Support Activities for Oil and Gas Operations.	$35.5 million	3.19	0.05	0.13	0.04	0.01	0.04	0.00	NA
	221	Utilities	500 employees	3.19	0.01	0.09	0.01	0.01	0.02	0.00	NA
	486	Pipeline Transportation.	$25.5 million	3.19	0.03	0.05	0.02	0.03	0.03	0.04	NA
Onshore Petroleum and Natural Gas Gathering and Boosting.	211	Oil and Gas Extraction.	500 employees	24.70	0.06	0.36	0.03	0.01	0.08	0.00	0.00
	213111	Drilling Oil and Gas Wells.	500 employees	24.70	0.23	0.84	0.27	0.05	0.16	0.02	0.01
	213112	Support Activities for Oil and Gas Operations.	$35.5 million	24.70	0.38	1.04	0.32	0.07	0.27	0.02	NA
	221	Utilities	500 employees	24.70	0.07	0.70	0.12	0.05	0.16	0.04	NA
	486	Pipeline Transportation.	$25.5 million	24.70	0.24	0.37	0.15	0.22	0.22	0.28	NA

[a] The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the Small Business Administration (SBA)'s business size definitions (*http://www.sba.gov/size*) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses.

[b] The Census Bureau has missing data ranges for this employee range. Hence the receipts are an underestimate of the true value. Therefore, the cost-to-sales ratio is a conservative estimate.

[17] The EPA's RFA guidance for rule writers suggests the ''sales'' test continues to be the preferred quantitative metric for economic impact screening analysis.

As shown, the cost-to-sales ratios are less than 1 percent for all establishments, except the ratio for the 1–20 employee range for facilities in the Onshore Petroleum and Natural Gas Production segment with NAICS code 213111, which is 1 percent, and the ratios for the 1–20 employee range for facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting segments with NAICS code 213112, which are greater than 1 percent but less than 2 percent. The petroleum and natural gas industry has a large number of enterprises, the majority of them in the 1–20 employee range. However, a large fraction of production comes from large corporations and not those with less than 20 employee enterprises. The smaller enterprises in most cases deal with very small operations (such as a single family owning a few production wells) that are unlikely to cross the 25,000 metric tons CO_2e threshold considered for the rule. An exception to such a scenario is a small (less than 20 employee) enterprise owning large operations but conducting nearly all of its operations through contractors. This is not an uncommon practice in the Onshore Petroleum and Natural Gas Production segment. Such enterprises, however, are a very small group among the almost 16,000 enterprises in the less than 20 employee category, and the EPA proposes to cover them in the rule.

The EPA took a conservative approach with the model entity analysis. Although the appropriate SBA size definition should be applied at the parent company (enterprise) level, data limitations allowed us only to compute and compare ratios for a model establishment within several enterprise size ranges.

Although this rule will not have a significant economic impact on a substantial number of small entities, the agency nonetheless tried to reduce the impact of this rule on small entities. See Section V.C of this preamble for more detail on the measures taken by the EPA to ensure that the burdens imposed on small entities would be minimal.

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).

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to 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 2300.16. 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.

This action proposes to add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. Impacts associated with the proposed changes to the monitoring and reporting requirements are detailed in the memorandum ''Assessment of Impacts of the 2015 Proposed Revisions to Subpart W'' (see Docket ID No. EPA–HQ–OAR–2014–0831). Burden is defined at 5 CFR 1320.3(b).

The estimated projected cost and hour burden associated with reporting for the proposed amendments to subpart W affecting the three industry segments are $7.2 million and 73,000 hours, respectively. For the hour burden, the estimated average burden hours per new response is 113 hours, the proposed frequency of response is once annually, and the estimated number of likely new respondents that would result from these proposed amendments is approximately 400.

The estimated total projected cost and hour burden associated with all ten subpart W industry segments are 317,400 hours and $29.2 million per year for a 3-year period, where identical annual costs are anticipated for all 3 years. The average annual burden to the EPA for this period is estimated to be 10,400 hours for oversight activities. The annual reporting and recordkeeping burden for this collection of information is estimated to average 63.4 hours per response.

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.

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–2014–0831. 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 December 9, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by January 8, 2015. 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

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.

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. 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 may result in a burden increase on subpart W reporters, but the EPA has determined that it is not a significant increase. See Section IV.B of this preamble for more details on the analysis of the potential impact of this proposal on small business entities.

Although this proposed rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless has tried to reduce the impact of this rule on small entities. As part of the process of 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 supports a ''help desk'' for the GHGRP, which would be available to answer questions on the provisions in this rulemaking. 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. We continue to be interested in the potential impacts of the proposed rule amendments on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

The proposed amendments and confidentiality determinations do 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. This action proposes to add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. This action also proposes confidentiality determinations for reported data elements. As discussed in Section V.B of this preamble, for the first year, the estimated total projected cost and hour burden associated with reporting for the proposed amendments to subpart W affecting the three industry segments are $7.2 million and 73,000 hours, respectively. Thus, this proposed rule is not subject to the requirements of section 202 and 205 of the Unfunded Mandates Reform Act of 1995 (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. As discussed in Section V.B of this preamble, the total collective impact on regulated entities is $7.2 million annually. Because this impact on each individual facility is estimated to be approximately $9,000 annually, the EPA has determined that the provisions in this action would not significantly impact small governments. In addition, because none of the provisions apply specifically to small governments, the EPA has determined that the provisions in this action would not uniquely impact 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. 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 add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. This action also proposes confidentiality determinations for reported data elements. 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.

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

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

The EPA has concluded that this action may have tribal implications. However, it will neither impose substantial direct compliance costs on tribal governments, nor preempt tribal law. This action proposes to add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. This action also proposes confidentiality determinations for reported data elements. 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, it is possible that there may be some facilities owned by tribal governments.

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. In particular, the EPA 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). 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 proposed 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 proposed action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Part 98 relates to monitoring, reporting, and recordkeeping and does not impact energy supply, distribution, or use. This action proposes to add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. This action also proposes confidentiality determinations for reported data elements.

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, 12(d) (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 the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking does not involve any new technical standards. 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.

The EPA has determined that these proposed rule amendments will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because the amendments do not affect the level of protection provided to human health or the environment. This is because the proposed amendments address information collection and reporting and verification procedures.

List of Subjects in 40 CFR Part 98

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

Dated: November 13, 2014.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations as amended November 25, 2014 at 79 FR 70351, and effective January 1, 2015, is proposed to be further 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, *et seq.*

Subpart W—Petroleum and Natural Gas Systems

■ 2. Section 98.230 is amended by adding paragraphs (a)(9) and (10) to read as follows:

§§ 98.230 Definition of the source category.

(a) * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares.

(10) *Onshore natural gas transmission pipeline.* Onshore natural gas transmission pipeline means all natural gas transmission pipelines as defined in § 98.238.

* * * * *

■ 3. Section 98.231 is amended by revising paragraph (a) to read as follows:

§ 98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of § 98.2(a)(2), except for the industry segments in paragraphs (a)(1) through (4) of this section.

(1) Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in paragraph § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year.

(2) Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in paragraph § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(3) Facilities must report emissions from the onshore petroleum and natural gas gathering and boosting industry segment only if emission sources specified in paragraph § 98.232(j) emit 25,000 metric tons of CO_2 equivalent or more per year.

(4) Facilities must report emissions from the onshore natural gas transmission pipeline industry segment only if emission sources specified in § 98.232(m) emit 25,000 metric tons of CO_2 equivalent or more per year.

* * * * *

■ 4. Section 98.232 is amended by:

■ a. Revising paragraphs (a) and (c)(6) and (8);

■ b. Adding paragraph (j);

■ c. Revising paragraph (k); and

■ d. Adding paragraph (m).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (j) and (m) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (b) through (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

* * * * *

(c) * * *

(6) Well venting during well completions with hydraulic fracturing.

* * * * *

(8) Well venting during well workovers with hydraulic fracturing.

* * * * *

(j) For an onshore petroleum and natural gas gathering and boosting facility, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Natural gas pneumatic device venting.

(2) Natural gas driven pneumatic pump venting.

(3) Acid gas removal vents.

(4) Dehydrator vents.

(5) Blowdown vent stacks.

(6) Storage tank vented emissions.

(7) Flare stack emissions.

(8) Centrifugal compressor venting.

(9) Reciprocating compressor venting.

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(11) Gathering pipeline equipment leaks.

(12) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas gathering and boosting facility as defined in § 98.238. Stationary or portable equipment includes the following equipment, which are integral to the movement of natural gas: natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section. Onshore petroleum and natural gas gathering and boosting facilities must report stationary and portable combustion emissions as specified in paragraph (j) of this section.

* * * * *

(m) For onshore natural gas transmission pipeline, report CO_2 and CH_4 emissions from blowdown vent stacks.

■ 5. Section 98.233 is amended by:

■ a. Revising the parameters ''EF_t'' and ''GHG_i'' of Equation W–1 in paragraph (a);

■ b. Revising paragraph (a)(2);

■ c. Revising the parameter ''EF'' of Equation W–2 in paragraph (c);

■ d. Revising paragraph (d)(8)(iii);

■ e. Revising paragraphs (g) introductory text, (g)(1) introductory text, (g)(1)(i) and the paragraph (g)(1)(ii) heading;

■ f. Revising the parameters ''FRM_s,'' ''$FR_{s,p}$'' and ''$PR_{s,p}$'' of Equation W–12A in paragraph (g)(1)(iii);

■ g. Revising the parameters ''$FRM_{i,}$'' and ''$PR_{s,p}$'' of Equation W–12B in paragraph (g)(1)(iv);

■ h. Revising paragraphs (g)(1)(v) and (vi);

■ i. Adding paragraph (g)(1)(vii);

■ j. Revising paragraph (g)(2) introductory text;

■ k. Adding paragraph (g)(2)(iv);

■ l. Revising paragraph (g)(4) introductory text;

■ m. Revising paragraphs (j) introductory text, (j)(1) introductory text, and (j)(6);

■ n. Revising paragraph (n)(2)(i);

■ o. Revising paragraphs (o) introductory text and (o)(10);

■ p. Revising paragraphs (p) introductory text and (p)(10);

■ q. Revising paragraphs (r) introductory text and (r)(2);

■ r. Revising paragraphs (u)(2)(i) and (iii); and

■ x. Revising paragraphs (z) introductory text and (z)(1)(ii).

The revisions and additions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) * * *

* * * * *

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. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W–1A.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting 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.

* * * * *

(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. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine ''$Count_t$'' for Equation W–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.

* * * * *

(c) * * *

* * * * *

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 and onshore petroleum and natural gas gathering and boosting facilities.

* * * * *

(d) * * *

(8) * * *

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas.

* * * * *

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using Equation W–10A or Equation W–10B of this section. Equation W–10A applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers and Equation W–10B applies when the gas flowback vent or flare volume is measured for each completion or workover. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use Equation W–10A of this section, you must follow the procedures specified in paragraph (g)(1) of this section. If you elect to use Equation W–10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. Emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

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

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

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each sub-basin and well type combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of routing to open tanks/pits.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas 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 gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, expressed in standard cubic feet per hour, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of each well p, in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job 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 of vented or flared gas for each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

$FR_{p,i}$ = Flow rate vented or flared of each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in § 98.234(b).

(1) If you elect to use Equation W–10A of this section on gas wells, 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. If you elect to use Equation W–10A of this section on oil wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

(i) *Calculation Method 1.* You must use Equation W–12A as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W–12B as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas 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, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in § 98.234(b).

(ii) *Calculation Method 2 (for gas wells).* * * *

(iii) * * *

* * * * *

FRM_s = Ratio of average gas flowback rate, during the period of time when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or calculated average flowback rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured and calculated FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W–33 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 gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

* * * * *

(iv) * * *

* * * * *

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, for the period of flow to open tanks/pits.

* * * * *

$PR_{s,p}$ = Average gas production flow rate during the first 30-days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour of each well, p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

* * * * *

(v) For Equation W–10A of this section, the ratio of gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate are applied to all well completions and well workovers, respectively, in the sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average gas production rate for each of these wells.

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

(vii) For oil wells where the gas production rate is not metered and you elect to use Equation W–10A of this section, calculate the average gas production rate ($PR_{s,p}$) using Equation W–12C of this section. If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraphs (g)(1)(vii)(A) or (g)(1)(vii)(B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

$$PR_{s,p} = GOR_p * \frac{V_p}{720} \qquad \text{(Eq. W-12C)}$$

Where:

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of well p, in the sub-basin and well type combination.

GOR_p = Average gas to oil ratio during the first 30 days of production after completions of newly drilled wells or workovers using hydraulic fracturing in standard cubic feet of gas per barrel of oil for each well p, that was measured in the sub-basin and well type combination; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in barrels of each well p, that was measured in the sub-basin and well type combination.

720 = Conversion from 30 days of production to hourly production rate.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in § 98.234(b).

(2) For paragraphs (g) introductory text and (g)(1) of this section, measurements and calculations are completed separately for workovers and completions per sub-basin and well type combination. A well type combination is a unique combination of the parameters listed in paragraphs (g)(2)(i) through (iv) of this section.

* * * * *

(iv) Oil well or gas well.

* * * * *

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

* * * * *

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For hydrocarbon liquids flowing directly to atmospheric storage tanks without passing through a wellhead separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(4) 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)(5) 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)(6) of this section.

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last

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:

* * * * *

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

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

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 or 2 in paragraphs (j)(1) and (2) of this section (with 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 separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

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

8,760 = Conversion to hourly emissions.

* * * * *

(n) * * *

(2) * * *

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

* * * * *

(o) *Centrifugal compressor venting.* If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) of this section do not apply. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section.

* * * * *

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–25 of this section.

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

Where:

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

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

$EF_{i,s}$ = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (p)(1) through (12) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) of this section do not apply. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section.

* * * * *

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–29D of this section.

$$E_{s,i} = Count_e * EF_{i,s} \qquad (Eq.\ W-29D)$$

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.

* * * * *

(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), (i)(6), (j)(9), and (j)(10) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (r) and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B and according to paragraph (r)(6)(ii) of this section.

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

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

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, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations, in standard cubic feet.

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting 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. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines. Underground natural gas storage facilities must count each component listed in Table W–4 of this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W–7 of this subpart.

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

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

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs, as determined in Equation W–31.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; 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_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.

* * * * *

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W–1A of this subpart. Major equipment and components associated with gas wells and onshore petroleum and natural gas gathering and boosting systems 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), except for miles of gathering pipelines, which must be determined using Component Count Method 2 in paragraph (r)(2)(ii) of this section. 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 and onshore petroleum and natural gas gathering and boosting 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 for onshore natural gas production and onshore petroleum and natural gas gathering and boosting; and Table W–1C of this subpart for onshore oil production. 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.

* * * * *

(u) * * *

(2) * * *

(i) *GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities.* If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

* * * * *

(iii) *GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment and the onshore natural gas transmission pipeline industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

* * * * *

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (z)(3) and (4) of this section, as follows:

(1) * * *

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

* * * * *

■ 6. Section 98.234 is amended by adding paragraph (g) to read as follows:

§ 98.234 Monitoring and QA/QC requirements.

* * * * *

(g) Special reporting provisions for best available monitoring methods in reporting year 2016.

(1) *Best available monitoring methods.* From January 1, 2016 to March 31, 2016, you must use the calculation methodologies and equations in § 98.233 but you may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2016 as specified in paragraphs (g)(2) through (5) of this section. Starting no later than April 1, 2016, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraph (g)(6) of this section. Best available monitoring methods means any of the following methods:

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

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Best available monitoring methods for well-related measurement data for oil wells with hydraulic fracturing.* You may use best available monitoring methods for any well-related measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for venting during well completions and workovers of oil wells with hydraulic fracturing.

(3) *Best available monitoring methods for onshore petroleum and natural gas gathering and boosting facilities.* You may use best available monitoring methods for any leak detection and/or measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in § 98.233(d).

(4) *Best available monitoring methods for natural gas transmission pipelines.* You may use best available monitoring methods for any measurement data for natural gas transmission pipelines that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for blowdown vent stacks.

(5) *Best available monitoring methods for specified activity data.* You may use best available monitoring methods for activity data as listed in paragraphs (g)(5)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for well completions and workovers of oil wells with hydraulic fracturing, onshore petroleum and natural gas gathering and boosting facilities, or natural gas transmission pipelines.

(i) Cumulative hours of venting, days, or times of operation in § 98.233(e), (g), (o), (p), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in § 98.233(g) and (i).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (n), and (z).

(6) *Requests for extension of the use of best available monitoring methods beyond March 31, 2016.* You may submit a request to the Administrator to use one or more best available monitoring methods for sources listed in paragraphs (g)(2) through (5), of this section beyond March 31, 2016.

(i) *Timing of request.* The extension request must be submitted to EPA no later than January 31, 2016.

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

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

(B) For each specific source type for which you are requesting use of best available monitoring methods, a description of the reasons that the needed equipment could not be obtained and installed before April 1, 2016.

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

(iii) *Approval criteria.* To obtain approval to use best available monitoring methods after March 31, 2016, you must submit a request demonstrating to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2016. The use of best available methods under this paragraph (g) will not be approved beyond December 31, 2016.

* * * * *

■ 7. Section 98.236 is amended by:
■ a. Revising paragraph (a) introductory text;
■ b. Adding paragraphs (a)(9) and (10);
■ c. Revising paragraphs (b)(1)(ii)(A) and (B) and (c) introductory text;
■ d. Redesignating paragraphs (c)(2) through (4) as paragraphs (c)(3) through (5), respectively;
■ e. Adding new paragraph (c)(2);
■ f. Revising paragraphs (d)(1) introductory text and (d)(1)(i);
■ g. Redesignating paragraphs (d)(1)(ii) through (vi) as paragraphs (d)(1)(iii) through (vii), respectively;
■ h. Adding new paragraph (d)(1)(ii);
■ i. Revising newly redesignated paragraph (d)(1)(vii);
■ j. Revising paragraphs (e)(1) introductory text and (e)(1)(i);
■ k. Redesignating paragraphs (e)(1)(ii) through (xviii) as paragraphs (e)(1)(iii) through (xix), respectively;
■ l. Adding new paragraph (e)(1)(ii);
■ m. Revising newly redesignated paragraphs (e)(1)(xvii) introductory text, (e)(1)(xviii) introductory text, and (e)(1)(xix);
■ n. Revising paragraph (e)(2) introductory text;
■ o. Redesignating paragraphs (e)(2)(ii) through (v) as paragraphs (e)(2)(iii) through (vi), respectively;
■ q. Adding new paragraph (e)(2)(ii);
■ p. Revising newly redesignated paragraphs (e)(2)(iii), (e)(1)(iv), (e)(2)(v) introductory text, and (e)(2)(vi) introductory text;
■ q. Revising paragraphs (e)(3)(i) introductory text, (f)(1)(ii), (f)(1)(xi)(A), (f)(1)(xii)(A), (f)(2)(i), (g) introductory text, (g)(1), (g)(2), (g)(5)(i), and (g)(5)(ii);
■ r. Adding paragraph (g)(5)(iii);
■ s. Revising paragraph (g)(6);
■ t. Revising paragraphs (h)(1)(i), (h)(1)(iv), (h)(2)(i), (h)(2)(iv), (h)(3)(i), (h)(4)(i) and (i) introductory text;
■ u. Adding paragraph (i)(3);
■ v. Revising paragraphs (j) introductory text and (j)(1) introductory text;
■ w. Redesignating paragraphs (j)(1)(ii) through (xiv) as paragraphs (j)(1)(iv) through (xvi), respectively;
■ x. Adding new paragraphs (j)(1)(ii) and (j)(1)(iii);
■ y. Revising newly redesignated paragraphs (j)(1)(v), (j)(1)(ix), (j)(1)(x), (j)(1)(xiv) introductory text, (j)(1)(xv) introductory text, and (j)(1)(xvi) introductory text;
■ z. Revising paragraphs (j)(2)(i) introductory text, (j)(2)(i)(A) through (j)(2)(i)(C), (j)(2)(ii)(B), (j)(2)(iii)(B), and (l)(1) introductory text;
■ aa. Redesignating paragraphs (l)(1)(ii) through (vi) as paragraphs (l)(1)(iii) through (vii), respectively;
■ bb. Adding new paragraph (l)(1)(ii);
■ cc. Revising newly designated paragraph (l)(1)(v);
■ dd. Revising paragraph (l)(2) introductory text;
■ ee. Redesignating paragraphs (l)(2)(ii) through (vii) as paragraphs (l)(2)(iii) through (viii), respectively;
■ ff. Adding new paragraph (l)(2)(ii);
■ gg. Revising newly designated paragraph (l)(2)(v);
■ hh. Revising paragraph (l)(3) introductory text;
■ ii. Redesignating paragraphs (l)(3)(ii) through (v) as paragraphs (l)(3)(iii) through (vi), respectively;
■ jj. Adding new paragraph (l)(3)(ii);
■ kk. Revising newly designated paragraph (l)(3)(iv);
■ ll. Revising paragraph (l)(4) introductory text;
■ mm. Redesignating paragraphs (l)(4)(ii) through (vi) as paragraphs (l)(4)(iii) through (vii), respectively;
■ nn. Adding new paragraph (l)(4)(ii);
■ oo. Revising newly designated paragraph (l)(4)(iv);
■ pp. Revising paragraphs (m)(1), (m)(5), (m)(6), (m)(7)(i), (m)(8)(i), (n) introductory text and (n)(1);
■ qq. Adding paragraph (n)(13);
■ rr. Revising paragraphs (o) introductory text and (o)(5) introductory text;
■ ss. Redesignating paragraphs (o)(5)(ii) and (iii) as paragraphs (o)(5)(iii) and (iv), respectively;
■ tt. Adding new paragraph (o)(5)(ii);
■ uu. Revising paragraphs (p) introductory text and (p)(5) introductory text;
■ vv. Redesignating paragraphs (p)(5)(ii) and (iii) as paragraphs (p)(5)(iii) and (iv), respectively;
■ ww. Adding new paragraph (p)(5)(ii);
■ xx. Revising paragraphs (r)(1) introductory text, (r)(1)(i), (r)(3) introductory text, (r)(3)(ii), (w)(2), and (x) introductory text;
■ yy. Redesignating paragraphs (x)(2) through (4) as paragraphs (x)(3) through (5), respectively;
■ zz. Adding new paragraph (x)(2);
■ aaa. Revising paragraphs (z) introductory text and (z)(1) introductory text;
■ bbb. Adding new paragraph (z)(1)(iii);
■ ccc. Revising paragraph (z)(2) introductory text;
■ ddd. Redesignating paragraphs (z)(2)(ii) through (vi) as paragraphs (z)(2)(iii) through (vii), respectively;
■ eee. Adding new paragraph (z)(2)(ii);
■ fff. Revising paragraphs (aa) introductory text and (aa)(1)(ii)(D) through (H);
■ ggg. Adding paragraphs (aa)(10) and (11); and
■ hhh. Revising paragraph (cc).

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

* * * * *

(a) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10) of this section, and each applicable emission source listed in paragraphs (b) through (z) of this section.

* * * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *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) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(vi) *Storage tanks.* Report the information specified in paragraph (j) of this section.

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

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

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

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

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

(10) *Onshore natural gas transmission pipeline.* For blowdown vent stacks, report the information specified in paragraph (i) of this section.

(b) * * *

(1) * * *

(ii) * * *

(A) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are counted. A list of the well ID numbers associated with the devices that are counted (for the onshore petroleum and natural gas production industry segment only).

(B) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are estimated (not counted). A list of the well ID numbers associated with the devices that are estimated (not counted) (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(c) *Natural gas driven pneumatic pumps.* You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (5) of this section.

* * * * *

(2) A list of the well ID numbers associated with the natural gas driven pneumatic pumps (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(d) * * *

(1) You must report the information specified in paragraphs (d)(1)(i) through (vii) 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 and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

(ii) A list of the well ID number(s) associated with the acid gas removal units (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(vii) Sub-basin ID that best represents the wells and/or equipment supplying gas to the unit (for the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments only).

* * * * *

(e) * * *

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

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

(ii) A list of well ID number(s) associated with the dehydrators (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(xvii) 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)(xvii)(A) through (C) of this section for these emissions from the dehydrator.

(xviii) 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)(xviii)(A) and (B) of this section for those emissions from the dehydrator.

(xix) Sub-basin ID that best represents the wells and/or equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments 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 (vi) of this section for the entire facility.

* * * * *

(ii) A list of the well ID numbers associated with the dehydrators at the facility (for the onshore petroleum and natural gas production industry segment only).

(iii) Whether any dehydrator emissions were vented to a vapor recovery device. If any dehydrator emissions were vented to a vapor recovery device, then you must report the total number of dehydrators at the facility that vented to a vapor recovery device. For the onshore petroleum and natural gas production industry segment only, also report a list of the associated well ID numbers.

(iv) Whether any dehydrator emissions were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a control device(s) other than a vapor recovery device or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were vented to each type of control device. For the onshore petroleum and natural gas production industry segment only, also report a list of the associated well ID numbers for each type of control device.

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

* * * * *

(vi) 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)(vi)(A) and (B) of this section.

* * * * *

(3) * * *

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

* * * * *

(f) * * *

(1) * * *

(ii) Well tubing diameter and pressure group ID and a list of the well ID numbers associated with each sub-basin well tubing diameter and pressure group ID.

* * * * *

(xi) * * *

(A) Well ID number of tested well.

* * * * *

(xii) * * *

(A) Well ID number.

* * * * *

(2) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin.

* * * * *

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

(1) Sub-basin ID and a list of the well ID numbers associated with each sub-basin that had completions or workovers with hydraulic fracturing during the calendar year.

(2) Well type combination (horizontal or vertical, gas well or oil well).

* * * * *

(5) * * *

(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of ''$T_{p,i}$'' and sum of ''$T_{p,s}$'' values used in Equation W–10A). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number.

(ii) For the measured well(s), the flowback rate, in standard cubic feet per hour, for each sub-basin (average of ''$FR_{s,p}$'' values in Equation W–12A), and the well ID numbers of the wells for which it is measured. You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured flowback rate during well completion or workover and the well ID number(s) for the well(s) included in the measurement.

(iii) If you used Equation W–12C to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil (''GOR_p'' in Equation W–12C).

(B) Volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels (''V_p'' in Equation W–12C).

(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 information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin (''$FV_{s,p}$'' in Equation W–10B).

(ii) Flow rate, in standard cubic feet per hour, at the beginning of the period of time when sufficient quantities of gas are present to enable separation (''$FR_{p,i}$'' in Equation W–10B).

(iii) The well ID number for which vented natural gas volume was measured.

* * * * *

(h) * * *

(1) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin without hydraulic fracturing and without flaring.

* * * * *

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all ''V_p'' used in Equation W–13B). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(2) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin without hydraulic fracturing and with flaring.

* * * * *

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all ''V_p'' from Equation W–13B). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(3) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin without hydraulic fracturing and without flaring.

* * * * *

(4) * * *

(i) Sub-basin ID and a list of well ID numbers associated with each sub-basin without hydraulic fracturing and with flaring.

* * * * *

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section.

* * * * *

(3) Onshore natural gas transmission pipeline segment. Report the information in paragraphs (i)(3)(i) to (i)(3)(iii) for each separate transmission pipeline blowdown event.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) The location of the blowdown, in latitude and longitude in decimal degree format provided as a comma-delimited ''latitude, longitude'' coordinate pair reported in decimal degrees to at least four digits to the right of the decimal point.

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2, and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xv) of this section for each sub-basin and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraph (j)(1)(xiii) of this section.

* * * * *

(ii) A list of the well ID number(s) associated with the tanks that controlled emissions with flares (for the onshore petroleum and natural gas production industry segment only).

(iii) A list of the well ID number(s) associated with the tanks that did not control emissions with flares (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(v) The total annual oil volume from gas-liquid separators and direct from wells that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells in the sub-basin flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total volume of oil from all wells and the well ID number(s) for the well(s) included in this volume.

* * * * *

(ix) The minimum and maximum concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(x) The minimum and maximum concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.

* * * * *

(xiv) 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)(xiv)(A) through (E) of this section.

* * * * *

(xv) 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)(xv)(A) through (C) of this section.

* * * * *

(xvi) 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)(xvi)(A) through (D) of this section.

* * * * *

(2) * * *

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3. Onshore gathering and boosting facilities do not report the information specified in paragraphs (j)(2)(i)(E) and (F) of this section.

(A) The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells in the sub-basin with oil production less than 10 barrels per day and that send oil to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual oil throughput from all wells and the well ID number(s) for the well(s) included in the measurement.

(B) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

* * * * *

(ii) * * *

(B) The number of atmospheric tanks in the sub-basin that did not control emissions with flares, including those that have vapor recovery, and for the onshore petroleum and natural gas production industry segment only, a list of the well ID numbers of the associated wells.

* * * * *

(iii) * * *

(B) The number of atmospheric tanks in the sub-basin that controlled emissions with flares, and for the onshore petroleum and natural gas production industry segment only, a list of the well ID numbers of the associated wells.

* * * * *

(l) * * *

(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 (vii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(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 (viii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(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 (vi) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(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 (vii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(m) * * *

(1) Sub-basin ID and a list of well ID numbers for wells in each sub-basin for which associated gas was vented or flared.

* * * * *

(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of ''$V_{p,q}$'' used in Equation W–18 of this subpart). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of ''SG'' values used in Equation W–18 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(7) * * *

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

* * * * *

(8) * * *

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

* * * * *

(n) *Flare stacks.* You must indicate if your facility contains any flare stacks. You must report the information specified in paragraphs (n)(1) through (13) 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 and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

* * * * *

(13) For the onshore petroleum and natural gas production industry segment, a list of the well ID numbers associated with flare stacks in each sub-basin.

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (o)(5)(i) through (iv) of this section.

* * * * *

(ii) A list of the well ID numbers for the wells at which these compressors are located (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (p)(5)(i) through (iv) of this section.

* * * * *

(ii) A list of the well ID numbers for the wells at which these compressors are located (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(r) * * *

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of this subpart. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W–32A of this subpart that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately by component type, service type, and geographic location (*i.e.,* Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the component type, service type, and geographic location. For the onshore petroleum and natural gas production facilities only, also report a list of well ID numbers for the associated wells.

* * * * *

(3) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

* * * * *

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W–1B and W–1C of this subpart.

* * * * *

(w) * * *

(2) EOR injection pump system identifier and a list of the well ID number(s) associated with each EOR injection pump.

* * * * *

(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 (5) of this section for each sub-basin category with EOR operations.

* * * * *

(2) A list of the well ID numbers associated with the EOR operations in each sub-basin.

* * * * *

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by § 98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraphs (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section. If your facility contains any combustion units subject to reporting according to paragraphs (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

(1) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour; or, internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 mmBtu/hr (or the equivalent of 130 horsepower). If the facility contains external fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour or internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 million Btu per hour (or the equivalent of 130 horsepower), then you must report the information specified in paragraphs (z)(1)(i) through (iii) of this section for each unit type.

* * * * *

(iii) A list of the well ID numbers associated with the combustion units (for the onshore petroleum and natural gas production industry segment only).

(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 (vii) for each combustion unit type and fuel type combination.

* * * * *

(ii) A list of the well ID numbers associated with the combustion units (for the onshore petroleum and natural gas production industry segment only).

* * * * *

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (11) 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) * * *

(ii) * * *

(D) The number of producing wells and a list of the well ID numbers at the end of the calendar year (exclude only those wells permanently taken out of production, *i.e.,* plugged and abandoned).

(E) The number of producing wells and a list of the well ID numbers acquired during the calendar year.

(F) The number of producing wells and a list of the well ID numbers divested during the calendar year.

(G) The number of wells and a list of the well ID numbers completed during the calendar year.

(H) The number of wells permanently taken out of production (*i.e.,* plugged and abandoned) and a list of the well ID numbers during the calendar year.

* * * * *

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (v) of this section.

(i) The quantity of produced gas throughput in the calendar year, in thousand standard cubic feet.

(ii) The quantity of produced gas consumed by the facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of produced condensate throughput in the calendar year, in barrels.

(iv) The quantity of produced oil throughput in the calendar year, in barrels.

(v) The quantity of gas flared, vented and/or unaccounted for in the calendar year, in thousand standard cubic feet.

(11) For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from 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 transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

(v) The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.

(vi) The miles of transmission pipeline in the facility.

* * * * *

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (h)(1)(iv), (h)(2)(iv), (j)(1)(v), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4)(iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

■ 8. Section 98.238 is amended by adding definitions of ''Facility with respect to petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements,'' ''Facility with respect to the onshore natural gas transmission pipeline segment,'' ''Gathering and boosting system,'' ''Gathering and boosting system owner or operator,'' ''Onshore natural gas transmission pipeline owner or operator,'' and ''Well identification (ID) number'' in alphabetical order to read as follows:

§ 98.238 Definitions.

* * * * *

Facility with respect to petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements means all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in this section. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in this subpart.

Facility with respect to the onshore natural gas transmission pipeline segment means the total U.S. mileage of natural gas transmission pipelines, as defined in this section, owned and operated by an onshore natural gas transmission pipeline owner or operator as defined in this section.

* * * * *

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the gas transported.

* * * * *

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act.

* * * * *

Well identification (ID) number means the unique and permanent identification number assigned to a petroleum or natural gas well. If the well has been assigned a US Well Number, the well ID number required in this subpart is the US Well Number. If a US Well Number has not been assigned to the well, the well ID number is the identifier established by the well's permitting authority.

* * * * *

■ 9. Revise Table W–1A of Subpart W of part 98 to read as follows:

TABLE W–1A OF SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES

Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents [2]	1.39

TABLE W–1A OF SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES—Continued

Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other [5]	0.003
Population Emission Factors—Gathering Pipelines	
Gathering Pipeline [7]	2.81
Western U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other [5]	0.003
Population Emission Factors—Gathering Pipelines	
Gathering Pipeline [7]	2.81

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emission Factor is in units of "scf/hour/device."
[3] Emission Factor is in units of "scf/hour/pump."
[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."
[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."
[7] Emission factor is in units of "scf/hour/mile of pipeline."

■ 10. Amend Table W–1B of Subpart W of part 98 by revising the table heading to read as follows:

TABLE W–1B TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING EQUIPMENT

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