ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2014–0831; FRL–9935–50–OAR]

RIN 2060–AS37

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing revisions and confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule. These revisions include the addition of calculation methods and reporting requirements for greenhouse gas (GHG) 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 revisions also include the addition of well identification reporting requirements to improve the EPA's ability to verify reported data and enhance transparency. This action also finalizes confidentiality determinations for new data elements contained in these amendments.

DATES: This final rule is effective on January 1, 2016.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2014–0831. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343–9263; fax number: (202) 343–2342; email address: *GHGReportingRule@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Rule Web site, *http://www.epa.gov/ghgreporting/.* To submit a question, select Help Center, followed by ''Contact Us.''

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on the EPA's Greenhouse Gas Reporting Rule Web site at *http://www.epa.gov/ghgreporting/index.html.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. This final rule adds calculation methods, monitoring, and data reporting requirements and finalizes confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule (40 CFR part 98). The Administrator determined that 40 CFR part 98 is subject to the provisions of Clean Air Act (CAA) section 307(d). See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine''). Entities affected by this final rule are owners and operators of petroleum and natural gas systems that directly emit GHGs, which 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	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.
	221210	Natural gas distribution.
	486210	Pipeline transportation of natural gas.

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

What is the effective date? The final rule is effective on January 1, 2016.

Judicial Review. Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit (the Court) by December 21, 2015. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Section 307(d)(7)(B) of the CAA also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note that under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

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

AGR acid gas removal

API American Petroleum Institute
BAMM best available monitoring methods
CAA Clean Air Act
CBI confidential business information
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e carbon dioxide equivalent
e-GGRT Electronic Greenhouse Gas Reporting Tool
EPA U.S. Environmental Protection Agency
FERC Federal Energy Regulatory Commission
FR Federal Register
ft^3 cubic feet
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GOR gas to oil ratio
GRI Gas Research Institute
ICR information collection request
ID identification
LDC local distribution company
N_2O nitrous oxide
NAICS North American Industry Classification System
NGO non-government organization
NGPA Natural Gas Policy Act
NTTAA National Technology Transfer and Advancement Act
O&M operation and maintenance
OMB Office of Management and Budget
PHMSA Pipeline and Hazardous Materials Safety Administration
psi/ft pounds per square inch per foot
REC reduced emissions completion
RFA Regulatory Flexibility Act
scf standard cubic feet
scf/STB standard cubic feet per stock tank barrel
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
WWW worldwide web

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

I. Background

A. Organization of This Preamble

Section I of this preamble provides background information regarding the origin of the final amendments. This section also discusses the EPA's legal authority under the CAA to promulgate and amend 40 CFR part 98 of the Greenhouse Gas Reporting Rule (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 final amendments to part 98, subpart W (Petroleum and Natural Gas Systems) (hereafter referred to as ''subpart W''), including a summary of the major comments that the EPA considered in the development of this final rule. Section III of this preamble discusses the final confidentiality determinations for new data reporting elements. Section IV of this preamble discusses the impacts of the final amendments to subpart W. Finally, Section V of this preamble describes the statutory and executive order requirements applicable to this action.

B. Background on This Action

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).

On December 9, 2014, the EPA proposed ''2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (79 FR 76267) to require the reporting of GHG emissions from several sources that had not previously been included in subpart W. These sources include completions and workovers of oil wells with hydraulic fracturing, petroleum and natural gas gathering and boosting systems, and transmission pipeline blowdowns between compressor stations. The reporting requirements for completions and workovers of oil wells with hydraulic fracturing were proposed to be included as part of the existing Onshore Petroleum and Natural Gas Production industry segment. For the other sources, the EPA proposed two new industry segments: The Onshore Petroleum and Natural Gas Gathering and Boosting segment for petroleum and natural gas gathering and boosting facilities, and the Onshore Natural Gas Transmission Pipeline segment for transmission pipeline blowdowns between compressor stations. The EPA also proposed to require the reporting of a well identification number for oil and gas wells covered in the Onshore Petroleum and Natural Gas Production segment. In addition, the EPA proposed confidentiality determinations for new data elements contained in the proposed amendments. The public comment period for these proposed rule amendments ended on February 24, 2015, following a 2-week extension of the original comment period end date (80 FR 6495; February 5, 2015).

In this action, the EPA is finalizing additions and revisions to the subpart W calculation, monitoring, and reporting requirements for new sources, with some changes made in response to public comments. Responses to comments submitted on the proposed amendments can be found in sections II, III, and IV of this preamble as well as in ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. As noted in the preamble to the proposed amendments (79 FR 73148; December 9, 2014), these additions and revisions further the EPA's goals of improving the completeness, quality, accuracy, and transparency of data from this sector, and improving the ability of agencies and the public to use these GHG data to analyze emissions and understand emission trends.

The *Strategy to Reduce Methane Emissions* in the President's *Climate Action Plan* summarizes the sources of methane (CH_4) emissions, commits to new steps to cut emissions of this potent GHG, 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 CH_4 emissions from several sectors, including the oil and natural gas sector. In the strategy, the EPA was tasked to review regulatory requirements to address potential gaps in coverage, improve methods, and help ensure high quality data reporting.[1] The final revisions to subpart W covered in this action are responsive to this task by addressing data gaps in subpart W, specifying methods for measuring CH_4 emissions, and providing data that can be used to further analyze CH_4 emissions in this industry.

This action also addresses a petition the EPA received from a group of non-government organizations (NGOs) requesting 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 (''Petition for Rulemaking'').[2] Table 2 of this preamble summarizes how the EPA has responded to the Petition for Rulemaking. These revisions, and previously finalized revisions where noted in Table 2, reflect the EPA's complete response to the Petition for Rulemaking. It is our position that we have fully responded to the NGO petition, however, any requests included in the petition that have not been responded to in Table 2 are considered denied.

TABLE 2—EPA RESPONSE TO PETITION FOR RULEMAKING

Request in petition	EPA's response	Final rule citations (40 CFR)
Clarify that oil wells that co-produce natural gas (''co-producing wells''), specifically wells in tight-oil formations like the Bakken and Eagle Ford, are subject to the completion reporting requirements as currently written. Expand the well completion reporting requirements to all wells, ensuring co-producing wells in any formation type are required to report completion emissions.	The EPA is not changing the definition of ''gas well'' or ''oil well.'' Instead, the EPA is amending subpart W to require 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.	98.232(c)(6) 98.232(c)(8) 98.236(g)
Require reporting from facilities and pipelines in the gathering and boosting segment of the natural gas industry.	The EPA is finalizing the proposal to amend subpart W to add a new industry segment, Onshore Petroleum and Natural Gas Gathering and Boosting, which covers 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.	98.230(a)(9) 98.232(j) 98.233 (various) 98.236(a)(9)
Require reporting from transmission pipeline blowdown events.	The EPA is finalizing the proposal to add reporting requirements for emissions from natural gas transmission pipeline blowdowns between compressor stations in a new Onshore Natural Gas Transmission Pipeline segment.	98.230(a)(10) 98.232(m) 98.236(aa)(11)
Require reporters to include API well identification numbers along with their submissions to help the public and policymakers understand which sources are reporting and how the threshold may be adjusted to most effectively provide emissions information.	The EPA is requiring the reporting of well identification numbers for the Onshore Petroleum and Natural Gas Production segment for information related specifically to wells.	98.236(f), (g), (h), (l), and (m) 98.238
Phase out the use of best available monitoring methods (BAMM), which will further help to ensure Subpart W data are rigorous, and comprehensive.	Prior to these amendments, BAMM was discontinued for all sources except specific sources that were affected by the amendments finalized on November 25, 2014 (79 FR 70352); those BAMM provisions will be unavailable after December 31, 2015. Reporters will be allowed to use BAMM for the 2016 reporting year for only the new industry segments and emission sources included in this action. The EPA is not allowing the use of BAMM beyond 2016.	98.234(f) and (g)

[1] *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.*

[2] *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. Docket Item No. EPA–HQ–OAR–2014–0831–0005.

TABLE 2—EPA RESPONSE TO PETITION FOR RULEMAKING—Continued

Request in petition	EPA's response	Final rule citations (40 CFR)
Consider including advanced innovative monitoring methods as a way to accelerate development and deployment of real-time continuous CH_4 emission monitoring in the oil and natural gas sector.	The agency is assessing the potential opportunities for application of remote sensing technologies and other innovations in measurement or monitoring technology to identifying and calculating emissions from affected sources under subpart W and requested comment in the proposal. The EPA received multiple comments in response to the request for comments on the feasibility, possible regulatory approaches, and provisions necessary to incorporate or allow the use of advanced measurement or monitoring methods in subpart W. All of the comments received are included in "Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" in Docket ID No. EPA–HQ–OAR–2014–0831. The EPA is not including provisions related to advanced measurement or monitoring methods in this rule and is not responding to these comments in this rulemaking. Instead, 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.	

Legal Authority

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

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing final confidentiality determinations for the new data elements required by these amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information that qualifies for confidential treatment. The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA.

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

These amendments are effective on January 1, 2016. Thus, beginning on January 1, 2016, facilities must follow the revised methods in subpart W, as amended, to calculate emissions occurring during the 2016 calendar year (*i.e.,* reporting year 2016). The first annual reports of emissions calculated using the amended requirements will be those submitted by March 31, 2017, covering reporting year 2016. For reporting year 2015, reporters will continue to calculate emissions and other relevant data for the reports that are submitted according to the requirements in part 98 that are applicable to reporting year 2015 (*i.e.,* the requirements in place until the effective date of this final rule).

For reporting year 2016 only, we are allowing the use of best available monitoring methods (BAMM) on a short-term transitional basis for facilities new to reporting under subpart W as well as reporters of facilities subject to new monitoring requirements associated with these revisions. Reporters have the option of using BAMM for only the new industry segments and emission sources included in this action from January 1, 2016, to December 31, 2016, without seeking prior EPA approval. The EPA will not accept requests for an extension for the use of BAMM beyond the time periods listed above. The EPA is not allowing the use of BAMM for the new well identification number provisions in the Onshore Petroleum and Natural Gas Production segment because the well identification number is not a parameter that requires monitoring equipment to be measured and, therefore, does not meet the requirements for BAMM. In addition, reporters should already have well identification numbers readily available for all wells and associated equipment to which this reporting requirement applies. See section II.E of this preamble for more information.

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

In this action, the EPA is amending subpart W to require the reporting of GHG emissions from completions and workovers of oil wells with hydraulic fracturing as part of the existing Onshore Petroleum and Natural Gas Production industry segment. The EPA is also adding requirements for two new industry segments: the Onshore Petroleum and Natural Gas Gathering and Boosting segment for petroleum and natural gas gathering and boosting systems, and the Onshore Natural Gas Transmission Pipeline segment for transmission pipeline blowdowns between compressor stations. Finally, the EPA is requiring the reporting of well identification numbers for oil and gas well-specific information (*e.g.,* completions and workovers, associated gas venting and flaring) reported in the Onshore Petroleum and Natural Gas Production segment. The comments received on this rule generally did not dispute the merit of adding these new segments and sources to subpart W, but they did provide a number of suggestions regarding the technical details of monitoring, reporting, and applicability.

Sections II.A through II.E of this preamble describe the requirements and other amendments that we are finalizing in this rulemaking. Section II.A describes the final amendments for the reporting of GHG emissions from completions and workovers of oil wells with hydraulic fracturing. Section II.B describes the final amendments for the reporting of GHG emissions from sources in the new Onshore Petroleum and Natural Gas Gathering and Boosting segment. Section II.C describes the final amendments for the reporting of GHG emissions from sources in the new Onshore Natural Gas Transmission Pipeline segment. Section II.D describes the requirements for reporting well identification numbers for the Onshore Petroleum and Natural Gas Production segment. Finally, section II.E provides a summary of the final amendments to the best available monitoring method requirements. The amendments described in each section are followed by a summary of the major comments on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and the EPA's responses.

Finally, in the preamble to the proposed rule, the EPA stated that the agency 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'' (79 FR 73148; December 9, 2014). The EPA did not propose, and therefore is not finalizing, any amendments to subpart W to this effect, but the EPA did request 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. The EPA also requested comment on the memorandum ''Discussion Paper on Potential Implementation of Alternative Monitoring under the GHGRP'' in Docket ID No. EPA–HQ–OAR–2014–0831. All of the comments received are included in ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. The EPA will consider these comments in the context of any future action related to alternative monitoring.

The amendments in this action will advance EPA's goal of maximizing rule effectiveness. For example, these amendments provide clear monitoring, calculation and reporting requirements for new segments and sources in subpart W, thus enabling government, regulated entities, and the public to easily identify and understand rule requirements. In addition, specific changes such as increasing the flexibility and time period for transitional BAMM will make compliance easier than non-compliance.

These amendments will also improve the EPA's ability to assess compliance by adding reporting elements that allow the EPA to more thoroughly verify greenhouse gas data and understand trends in emissions. For example, the requirement for the Onshore Petroleum and Natural Gas Production segment to report well identification numbers will allow the EPA to link GHGRP data with other data sources and assess the completeness and representativeness of the data collected relative to all activity in the U.S. oil and gas production sector. Lastly, these amendments further advance the ability of the GHGRP to provide access to quality data on greenhouse gas emissions by adding key petroleum and natural gas emission sources to this program. One example is the addition of the Onshore Petroleum and Natural Gas Gathering and Boosting segment, a significant greenhouse gas emissions segment that had not been previously covered under the GHGRP.

A. Summary of Final Amendments for Oil Wells With Hydraulic Fracturing

1. Summary of Final Amendments

The EPA is amending subpart W to require 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. In general, commenters supported inclusion of emissions from completions and workovers of oil wells with hydraulic fracturing in subpart W, and a few commenters provided targeted technical edits and suggestions for this source. Consistent with the requirements for completions and workovers of gas wells with hydraulic fracturing, and consistent with the proposed requirements, the new provisions include the reporting of activity data on the number of completions and workovers of oil wells with hydraulic fracturing and on the use of flaring and reduced emission completions (RECs). In response to public comments, the final monitoring and reporting amendments do not apply to completions and workovers of oil wells with hydraulic fracturing that have a gas to oil ratio (GOR) of less than 300 standard cubic feet per stock tank barrel (scf/STB).

The EPA is also amending the equations and definitions in 40 CFR 98.233(g) to reflect applicability to completions and workovers of all gas and oil wells with hydraulic fracturing. As in the proposal, the final amendments require the use of either Equation W–10A or W–10B for calculating GHG emissions from completions and workovers of oil wells 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. As proposed, the EPA is finalizing that emissions be calculated and reported separately for gas wells and oil wells by sub-basin and well type combination.[3] Furthermore, as proposed, the final amendments require the use of 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 requirements for the location of the flow meter used to measure the gas flow rate for oil wells are the same as the location requirements for gas wells. Other provisions that apply to completions and workovers of gas wells with hydraulic fracturing also apply to completions and workovers of oil wells with hydraulic fracturing, including the determination of wells that constitute a representative sample for use in Equation W–10A.

For oil wells that do not meter gas production, such as some wells with a relatively low GOR, the EPA is adding a new Equation W–12C as proposed 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 Equation W–12C, the value of $PR_{s,p}$ is calculated by multiplying the GOR of the well by the measured oil production rate over the

[3] 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. See the definition of ''Sub-basin category, for onshore natural gas production'' in 40 CFR 98.238.

first 30 days of production after the completion or workover.

2. Summary of Comments and Responses

Comment: Several commenters responded to the EPA's request for 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. Most of these commenters supported establishment of a cutoff for wells with very low emissions. One commenter urged the EPA to require monitoring and reporting for all completions and workovers with hydraulic fracturing but stated that if a threshold is set, it should be set at a level that ensures that all significant emissions sources are included and that sources are able to clearly determine whether they are required to report. Three commenters supported setting a minimum GOR threshold. One commenter suggested a minimum GOR threshold of 300 and stated that, based on industry experience, oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. The second commenter agreed that operators should only have to monitor and report emissions if the GOR is great enough to operate a separator and direct measurement is possible. The third commenter supporting a minimum GOR threshold did not provide a suggestion for a specific numeric threshold but stated that the emissions from wells with a low GOR are insignificant, and the time and resources involved in measuring the flowback and reporting emissions for wells expected to have minimal emissions would outweigh any contribution of these emissions to the overall source category totals. This commenter supported the inclusion of a threshold so that only significant sources of emissions would be included.

Response: The EPA agrees that including a minimum GOR threshold will help minimize reporting burden while still capturing most of the emissions from this source. Energy Information Administration data show that the number of ''oil only'' wells drilled from 2007–2012 was less than 20 percent of all new wells.[4] These wells would have a GOR approaching zero and, therefore, would be expected to have low emissions. We believe that having no threshold may create an unnecessary burden for operators to report emissions for these wells with just a trace of gas. Given that the EPA is finalizing the proposed requirement that the oil well flow meter be located downstream of the separator, the separator must be operating for the owner or operator to be able to measure the flow rate and estimate emissions from completions and workovers of oil wells with hydraulic fracturing. One commenter, an industry trade association, suggested a threshold of 300 scf/STB based on the industry trade association's experience that separators typically do not operate at a GOR less than 300 scf/STB.

The primary concern when determining the level for a threshold is volatility; the threshold must be low enough that the oil produced is considered non-volatile. Non-volatile ''black oils'' (*i.e.,* oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900 scf/STB.[5] Oil wells with a GOR less than the 300 scf/STB suggested by the commenter are at the lower end of this range, and completions and workovers with hydraulic fracturing of these wells will not likely have enough gas associated that can be separated. Therefore, the final monitoring and reporting requirements do not apply to completions and workovers of oil wells with hydraulic fracturing that have a GOR of less than 300 scf/STB.

Comment: Several commenters responded to the EPA's request for comment on whether to establish a minimum well pressure threshold such that oil wells with a very low well pressure would not be subject to the monitoring and reporting requirements for GHG emissions from completions and workovers with hydraulic fracturing. Most of these commenters supported establishment of a cutoff for wells with very low well pressure. One commenter urged the EPA to require monitoring and reporting for all completions and workovers with hydraulic fracturing but stated that if a threshold is set, it should be set at a level that ensures that all significant emissions sources are included and that sources are able to clearly determine whether they are required to report. Three commenters supported setting a minimum well pressure threshold. One commenter suggested a minimum well pressure threshold of 0.4645 pounds per square inch per foot (psi/ft) because this is the vertical pressure gradient needed for a well to flow back, based on experience with the Natural Gas STAR program. The second commenter suggested that operators should only have to monitor and report emissions if the pressure of the reservoir during oil well completions and workovers is greater than the pressure gradient of 0.433 psi/ft and noted that the pressure needed varies based on the density of the materials in the column and the depth of the well. The third commenter supporting a minimum well pressure threshold did not provide a suggestion for a threshold but supported the inclusion of a threshold so that only significant sources of emissions would be included.

Response: The EPA evaluated the commenters' suggestions and has decided not to include a minimum well pressure threshold. Both commenters who suggested a specific value noted in their comments that these pressure gradients are the minimum needed for the well to produce. In other words, according to the commenters' rationale, wells with pressures below the suggested pressure thresholds would not have any production, regardless of whether a threshold is included in the final rule. As a result, specifying that reporting of emissions from completions and workovers of oil wells with hydraulic fracturing is not required below those pressures is redundant. Therefore, the final rule does not include a minimum well or reservoir pressure threshold for completions and workovers of oil wells with hydraulic fracturing.

B. Summary of Final Amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment

The EPA is amending subpart W to add a new industry segment, Onshore Petroleum and Natural Gas Gathering and Boosting, that covers 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

[4] In this analysis, all hydrocarbon production in the liquid state at the wellhead was considered oil. J. Lieskovsky and S. Gorgen. ''Drilling often results in both oil and natural gas production.'' *Today in Energy,* U.S. Energy Information Administration, October 29, 2013. *http://www.eia.gov/todayinenergy/detail.cfm?id=13571*. Accessed June 9, 2015.

[5] M.P. Walsh. ''Oil Reservoir Primary Drive Mechanisms.'' In *Petroleum Engineering Handbook, Volume V: Reservoir Engineering and Petrophysics,* E.D. Holstein (Ed.), L.W. Lake (Ed. in Chief), pp. V–895–980. Society of Petroleum Engineers, 2007.

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. Commenters generally supported inclusion of gathering and boosting system emissions in subpart W, and many commenters suggested targeted revisions concerning definitions, what emission sources should be included in the segment and methods for individual emission sources.

The remainder of this section describes the final reporting requirements for this new industry segment, including the segment description, definitions, calculation methods, and information to be reported. The amendments described in each section are followed by a summary of the major comments, if any, on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and the EPA's responses.

1. Segment Description for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment

a. Summary of Final Amendments

The EPA is finalizing the definition of 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 petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to, gathering pipelines, separators, compressors, acid gas removal (AGR) units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. The Onshore Petroleum and Natural Gas Gathering and Boosting segment does not include equipment and pipelines that are reported under any other industry segment defined in subpart W. The segment definition is being finalized as proposed, except that the final amendments provide two clarifications regarding gathering pipelines. First, gathering pipelines operating on a vacuum are not included because they would not be expected to have emissions. Second, to address comments regarding the inclusion of liquid and multiphase streams in the segment, the definition clarifies that gathering pipelines with a GOR less than 300 scf/STB are not a part of the segment.

b. Summary of Comments and Responses

Comment: Commenters requested that the EPA remove ''Petroleum and'' from the proposed segment name, ''Onshore Petroleum and Natural Gas Gathering and Boosting.'' The commenters asserted that the removal would provide a clear demarcation between onshore petroleum and natural gas production and onshore natural gas gathering and boosting. They also stated that such a change would be more consistent with the segment definition, which includes pipelines and equipment ''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.'' The commenter stated that the type of equipment included in the gathering and boosting segment is ''synonymous'' with gas gathering and boosting systems, not liquid or petroleum, and they noted that the emission factor for equipment leaks from gathering pipelines is not applicable to gathering pipelines that carry mostly liquid.

Commenters also specifically requested that the EPA exclude petroleum gathering pipelines from the gathering and boosting segment because the fugitive gas emissions from these gathering pipelines would be negligible. Both commenters stated that the proposed emission factor for gathering pipeline leaks is only applicable to gas gathering pipelines. Two commenters also requested that multi-phase flow lines from wells to a centralized production facility where initial separation occurs be retained in the Onshore Petroleum and Natural Gas Production segment rather than included in the new gathering and boosting segment.

Response: The EPA is finalizing the segment name as proposed and not removing ''Petroleum and'' from the segment name or moving multiphase gathering pipelines to the Onshore Petroleum and Natural Gas Production segment. We proposed including ''Petroleum and'' in the segment name to reflect the complex nature of upstream operations where wells can produce oil, natural gas, or a mixture of both and to signify the inclusion of GHG emissions from gathering and boosting systems moving high volatility liquids in this new segment. Even in wells that produce primarily liquids at surface temperature and pressure conditions, there is often a volatile gaseous component. This associated gas is usually considered wet due to the high content of natural gas liquids (volatile components) to go along with gaseous CH_4. Similarly, the inclusion of all petroleum gathering pipelines in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, including multiphase pipelines, is appropriate, because gathering lines are a key component to gathering and boosting systems. Therefore, all gathering pipelines that collect petroleum and/or natural gas from onshore production gas or oil wells and transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline are considered part of the final Onshore Petroleum and Natural Gas Gathering and Boosting segment.

However, the EPA does agree that gathering pipelines carrying mostly oil have a low potential for GHG emissions. We note that the ratio of CH_4 to volatile components increases as the GOR increases. Therefore, to clarify our intent to exclude gathering pipelines containing oil, the final rule clarifies that the Onshore Petroleum and Natural Gas Gathering and Boosting segment does not include gathering pipelines with a GOR of less than 300 scf/STB. Operators of gathering pipelines below that threshold are not required to include those pipelines in their gathering and boosting facility. See section II.B.5 of this preamble for additional discussion.

Finally, as part of evaluating this comment, the EPA reviewed the proposed definitions related to the Onshore Petroleum and Natural Gas Gathering and Boosting segment and recognizes that two of them referred to ''the gas'' rather than ''the petroleum and/or natural gas.'' One was the proposed description of the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230, as identified by the commenters, and the other was the definition of ''gathering and boosting system owner or operator'' in 40 CFR 98.238. For consistency throughout the final rule with the intent stated in this response, the final description of the Onshore

Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230 refers to ''petroleum and/or natural gas'' and the final definition of ''gathering and boosting system owner or operator'' in 40 CFR 98.238 refers to ''the petroleum or natural gas transported.''

Comment: One commenter stated that there may be confusion regarding which equipment should be reported in the different industry segments, which could lead to emissions being mistakenly excluded or double-counted. For example, gathering and boosting equipment located on a single well pad or associated with a single well pad could be double-counted, especially if it is operated by one entity but owned by another. The commenter also noted that confusion over the proper segment for this type of equipment could make the difference between reporting emissions or not reporting emissions if a facility is close to the reporting threshold of 25,000 metric tons carbon dioxide equivalent (CO_2e). Therefore, the commenter requested that the EPA incorporate by reference the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) federally defined boundaries of production, gathering and boosting, and transmission segments to ensure state/federal transparency and consistency.

Response: The EPA is not changing the segment description for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3). As stated at proposal, the EPA decided not to make any changes to the existing segment descriptions to provide consistency for reporters in that segment. This decision allows the EPA to ensure that the data gap in subpart W related to gathering and boosting systems is addressed while minimizing confusion over changes to other segments. Instead, the EPA is reiterating the intention for the Onshore Petroleum and Natural Gas Gathering and Boosting segment to cover equipment and emission sources not included in reporting for the existing Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments.

The EPA does not agree that emissions from the same equipment will be reported under more than one industry segment in a given reporting year; however, we acknowledge that similar equipment may exist in adjacent industry segments as defined in subpart W. The owner or operator of the equipment in question should first determine if that equipment is subject to reporting in another segment of subpart W, such as the Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments. If the equipment is not subject to reporting in another segment of subpart W, then the owner or operator should evaluate whether or not the equipment is included in the Onshore Petroleum and Natural Gas Gathering and Boosting source category. For example, if a gathering and boosting owner or operator also owns or operates equipment on or associated with a single well pad (40 CFR 98.230(a)(2)), that equipment is part of the Onshore Petroleum and Natural Gas Production segment, not the Onshore Petroleum and Natural Gas Gathering and Boosting segment. Therefore, emissions from that equipment should not be included when determining if the gathering and boosting facility exceeds the reporting threshold.

Comment: One commenter requested that the EPA clarify the proper segment for AGR units and revise the rule accordingly. The commenter suggested that the Natural Gas Processing segment should explicitly exclude sulfur dioxide and carbon dioxide (CO_2) removal units, so that it is clear that those units do not report under both the Natural Gas Processing segment and the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The commenter stated that this revision would be more consistent with the definition of gas processing plant in other EPA rules. If the EPA does not make this change, the commenter stated that AGR units should not be included in the Onshore Petroleum and Natural Gas Gathering and Boosting segment because they are already included in the Natural Gas Processing segment. The commenter noted that AGR units are specifically defined in 40 CFR 98.238 as a process unit that separates hydrogen sulfide and/or CO_2 from sour natural gas using liquid or solid absorbents or membrane separators.

Response: The EPA agrees that emissions from a particular acid gas removal unit should not be reported under both the Natural Gas Processing segment and the Onshore Petroleum and Natural Gas Gathering and Boosting segment. However, as noted previously in this preamble, the EPA is not changing the segment description for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3). Instead, the EPA is reiterating the intention for the Onshore Petroleum and Natural Gas Gathering and Boosting segment to cover equipment and emission sources not included in reporting for the Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments. The final segment description for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230(a)(10) specifies that gathering and boosting equipment does not include equipment reported under any other industry segment defined in 40 CFR 98.230(a), which should address the commenter's concern about reporting under multiple segments.

Regarding the commenter's suggestion to exclude AGR units from the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA believes AGR units should be reported under subpart W and that the current requirements, coupled with the revisions in this rulemaking, allow for a clear demarcation of where they should be included and reported. While most AGR units will be included in the Onshore Natural Gas Processing segment, the EPA does not agree that the Onshore Natural Gas Processing segment includes all AGR vents, particularly those in processes that do not fractionate gas liquids with an annual average throughput of less than 25 million scf per day. Therefore, the final Onshore Petroleum and Natural Gas Gathering and Boosting segment includes AGR vents that do not meet the segment descriptions for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3) but do meet the Onshore Petroleum and Natural Gas Gathering and Boosting segment description in 40 CFR 98.230(a)(10).

2. Definitions

a. Summary of Final Amendments

The EPA is finalizing the definition of ''gathering and boosting system'' as proposed and is finalizing the definition of ''gathering and boosting system owner or operator'' as proposed with a clarification that the fluid being transported may be petroleum or natural gas. Specifically, 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 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. A gathering and boosting system owner or operator is 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 petroleum or natural gas transported. In complex ownership scenarios, the owner/operator assigns a designated representative responsible for reporting consistent with 40 CFR 98.4.

The EPA is also finalizing the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting'' in 40 CFR 98.238 as proposed. A facility with respect to onshore petroleum and natural gas gathering and boosting is 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 are 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. Emissions from an onshore petroleum and natural gas gathering and boosting facility only need to be reported if the collection of emission sources emits 25,000 metric tons CO_2e or more per year.

b. Summary of Comments and Responses

Comment: Multiple commenters provided comments on the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting.'' Some commenters supported the basin-level approach that the EPA proposed, although a few asked the EPA to clarify how to report their emissions if their gathering and boosting system is in more than one basin. Other commenters disagreed with the basin-level approach and suggested that the EPA should use the definition of facility in 40 CFR 98.6. These commenters asserted that the basin-level approach would result in an expansive definition of facility that includes huge numbers of emissions sources and that this approach is not consistent with how a facility is defined elsewhere in the GHGRP or with traditional notions of aggregation under the CAA. One commenter asserted that defining a facility in a way that is not consistent with other CAA programs will make it difficult for the EPA to use the GHGRP data to inform future policy decisions. The commenter also stated that the EPA has not provided any explanation of why basin-wide aggregation is a reasonable data request under section 114 of the CAA.

Commenters opposing the basin-level facility definition noted that the Onshore Petroleum and Natural Gas Gathering and Boosting segment has very different characteristics from the Onshore Petroleum and Natural Gas Production segment, which also uses the basin-level approach to defining a facility. One commenter specifically noted that production sources are located at well-defined, discrete locations, owners and operators of production sites know where the wells are physically located and how many operate in a single production basin. In contrast, the commenter stated, the gathering and boosting operations of one owner or operator in a single hydrocarbon basin may include hundreds or thousands of miles of pipelines with multiple sites, including interconnects, meter stations, scrubber stations, pigging stations, compressor stations, and gas treating plants. Another commenter stated that gathering and boosting sites have the ability to boost and move gas from multiple basins within the same site, whereas production typically maintains operations and moves gas within one basin.

Another commenter also disagreed with the basin-level approach, noting that the term ''basin'' is not common terminology that is used in the gathering and boosting industry segment. The commenter suggested that the EPA use a county- or parish-level approach with an equipment threshold (to determine which equipment should be counted when determining if the 25,000 metric tons CO_2e reporting threshold has been exceeded).

Response: The EPA is finalizing the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as proposed. As noted in the preamble to the proposed amendments, the basin-level approach to defining a facility for the Onshore Petroleum and Natural Gas Gathering and Boosting segment is expected to achieve a balance of providing geographically specific information while also reducing burden on reporters. This approach also recognizes the fact that gathering and boosting facilities are more dispersed than processing facilities and are geographically similar to the Onshore Petroleum and Natural Gas Production segment in size and number of sources because, by their nature, they are needed to process and transport the petroleum and natural gas produced in a given basin. While some gathering and boosting operations may span multiple basins or may only be present in a portion of a basin, as will some onshore production operations, the EPA has concluded that a basin-level facility definition is the best reflection of how this industry is organized operationally.

In ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' (Docket Item No. EPA–HQ–OAR–2014–0831–0018), we evaluated the option of using the definition of ''facility'' found in 40 CFR 98.6 for gathering and boosting facilities, and we found that this definition would provide limited data on the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment compared to the basin-level approach, due to the fact that fewer facilities would exceed the 25,000 metric tons CO_2e reporting threshold. It would also likely be more burdensome overall to reporters, because a larger number of facilities would have to be evaluated to determine whether they exceed the 25,000 metric tons CO_2e reporting threshold, and a larger number of ''facility'' reports would be required for each owner or operator. The commenters did not provide any new information that would enable us to re-evaluate this conclusion. A county- or parish-level approach would similarly result in a larger number of smaller facilities to be evaluated to determine whether they exceed the reporting threshold than the basin-level approach. This approach would result in fewer facilities reporting than a basin-level definition, especially if an equipment threshold were defined as requested by the commenter, as well as a higher burden for owners or operators with multiple facilities in a basin that exceed the 25,000 metric tons CO_2e reporting threshold. Therefore, the EPA concluded that these options would not achieve the goals that were articulated in the preamble to the proposed rule of ''having a thorough data set and transparent, complete information for this sector while minimizing burden to reporters'' (79 FR 73156; December 9, 2014). For more detail on this analysis, see ''Greenhouse Gas Reporting Rule: Technical Support for Final 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. We disagree with the comment that aggregation of data would not provide a data set that the EPA can use to inform future policy decisions. The purpose of this rule is to collect emissions and activity data for this industry and understand the relative emission sources, which we anticipate the aggregated data will help to promote. Therefore, the aggregated data can still inform future GHG policy. As we have pointed out previously, the EPA's definition of ''facility'' for purposes of part 98 in no way impacts the ''facility'' definition for similar sources under existing CAA programs.[6] Information collected under part 98 can inform a number of different CAA programs and the Agency's authority under CAA section 114 as the basis for part 98 is independent from the EPA's authority for other CAA programs.

To address the commenters' question about reporting a system in two basins, we are confirming in this response that reporters should submit one report per basin (*i.e.,* per facility as it is defined in subpart W) and that the 25,000 metric tons CO_2e per year reporting threshold applies to each basin/facility separately. In other words, the reporter should determine the emissions from the portion of gathering and boosting system associated with each basin. If the total emissions in each basin exceed the 25,000 metric tons CO_2e per year reporting threshold, then the reporter submits two reports. If the total emissions in one basin exceed the 25,000 metric tons CO_2e threshold, but the emissions in the other basin are below the threshold, then the reporter submits one report (for the facility that exceeds the threshold).

Regarding the commenter's question regarding the reasonableness of collecting data at the basin-level under the CAA, the EPA established its basis for collecting basin-level data in the final subpart W rule, when the EPA finalized the requirements for the Onshore Petroleum and Natural Gas Production segment. Additionally, as noted earlier in this section, more granular collection of data for this segment would result in higher burden for owners or operators with multiple operations in a basin that exceed the 25,000 metric tons CO_2e reporting threshold. See also, ''Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document (Docket Item No. EPA–HQ–OAR–2009–0923–3610) and ''Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments'' (Docket Item No. EPA–HQ–OAR–2009–0923–3608).

3. Blowdown Vent Stacks

a. Summary of Final Amendments

The EPA is finalizing the requirements for blowdowns of equipment in the Onshore Petroleum and Natural Gas Gathering and Boosting segment with some clarifications from proposal. Emissions should be calculated using the same methods that are used for the Onshore Natural Gas Processing segment. The same exemptions, including those for volumes less than 50 cubic feet (ft^3) and for desiccant dehydrator reloading, apply to the Onshore Petroleum and Natural Gas Gathering and Boosting segment. In response to comments that the segment is geographically dispersed and blowdowns may occur without personnel on-site or nearby, making it difficult to determine emissions from a blowdown event, the final amendments specify that for emergency blowdowns, reporters may use engineering estimates based on best available information to determine the temperature and pressure used in Equation W–14A.

b. Summary of Comments and Responses

Comment: Commenters stated that the EPA should not include reporting of blowdown vent stack emissions due to the large burden on the reporter. Instead, the commenters stated, blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should be treated similarly to blowdowns in the Onshore Petroleum and Natural Gas Production segment, where they are excluded because they are not located at consolidated facility sites and are not manned. Commenters also stated that blowdowns from gathering and boosting systems contribute minimally to overall GHG emissions. One commenter noted that while there is an exemption for any blowdown of a volume less than 50 ft^3, there is also a burden to determine if the physical volume meets this reporting threshold. To reduce the burden, some commenters suggested only including emissions from blowdown vent stacks located at a facility site (*e.g.,* compressor station, central tank battery). Other commenters stated if blowdowns remain in the segment, the EPA should allow reporters to use an emission factor approach to calculate emissions. Another commenter stated that the EPA's supporting documentation focuses on gathering pipeline blowdowns, but the regulatory text appears to include all the blowdowns occurring within a basin, including individual equipment blowdowns. The commenter requested that the EPA clarify its intent if blowdowns remain in the segment.

Response: The EPA has evaluated these comments and has decided to finalize the reporting requirements for blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment with some revisions to address the commenters' concerns. While the EPA does recognize that many gathering and boosting systems are geographically dispersed, as noted by the commenters, the nature of the Onshore Petroleum and Natural Gas Gathering and Boosting segment is such that the amount of fluid passing through a gathering and boosting system will be much greater than the amount of fluid at individual well pads. Therefore, the EPA has determined that the potential for emissions from blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment is higher than blowdowns in the Onshore Petroleum and Natural Gas Production segment, and they should not be excluded. However, the EPA acknowledges that the geographic dispersion of the segment, and the fact that some blowdowns occur without facility personnel on site, may make it difficult to measure emissions from blowdowns, particularly emergency blowdowns. Therefore, the final amendments include a provision specifying that for emergency blowdowns, reporters may use engineering estimates based on best available information to determine the temperature at actual conditions in the unique physical volume and absolute pressure at actual conditions in the unique physical volume for use in Equation W–14A.

To respond to the commenter's request regarding whether only gathering pipeline blowdowns or all equipment blowdowns should be included, the EPA is clarifying that the intent is to include emissions from the ''blowdown vent stacks'' source type as defined in subpart A of part 98. The focus on blowdown vent stacks located on gathering pipelines in the supporting documentation was not intended to imply that only gathering pipeline blowdowns should be reported. On the

[6] Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems, Docket Id. No. EPA–HQ–OAR–2009–0923.

contrary, the proposal supporting documentation reflects the fact that the EPA expected that blowdown vent stacks located at boosting stations would be similar to blowdown vent stacks in other industry segments and conducted a separate evaluation to determine whether the same calculation methods would be appropriate for gathering pipeline blowdown vent stacks. The final rule supporting documentation more clearly reflects this intent. The EPA also notes that while measuring equipment to determine whether it exceeds the 50 ft^3 physical volume threshold for reporting may create an initial burden on reporters, the threshold will lead to a burden reduction as reporters become familiar with the identification process.

4. Storage Tank Vented Emissions

a. Summary of Final Amendments

The EPA is finalizing the same methods for calculating emissions for atmospheric storage tanks located in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as in the Onshore Petroleum and Natural Gas Production segment, as proposed but with a few clarifications. Specifically, the EPA is clarifying some of the language within 40 CFR 98.233(j) and 40 CFR 98.236(j) that was originally written to apply to Onshore Petroleum and Natural Gas Production facilities and not proposed to be amended to also apply to storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment. In particular, references to a ''wellhead separator'' have been clarified to refer simply to a ''separator,'' which is a defined term in 40 CFR 98.238. To accommodate Onshore Petroleum and Natural Gas Gathering and Boosting storage tanks that do not receive hydrocarbon liquids from a separator or well, Calculation Methods 1 and 2 have been amended to specify how to estimate emissions if liquids are received from non-separator equipment. In addition, certain instances of ''sub-basin'' have been amended to refer to ''county'' to clarify the requirements for Onshore Petroleum and Natural Gas Gathering and Boosting reporters. All other provisions in 40 CFR 98.233(j) apply to the Onshore Petroleum and Natural Gas Gathering and Boosting segment, including the 10 barrels per day threshold for determining which calculation method may be used for estimating emissions.

b. Summary of Comments and Responses

Comment: One commenter stated that combining the requirements for storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment and the Onshore Petroleum and Natural Gas Production segment results in confusing terminology and unclear requirements. In particular, the commenter noted that the terms ''separator(s),'' ''gas-liquid separator(s),'' ''wellhead separator(s),'' and ''wellhead gas-liquid separator(s),'' appear throughout the storage tank requirements. The commenter asked whether the EPA intended all of these terms to refer to the same equipment. The commenter also noted that not all gathering and boosting system storage tanks receive liquids directly from separators, and no gathering and boosting storage tanks receive liquids directly from wellhead separators. Therefore, the commenter stated, the requirements for storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment are unclear.

The commenter also noted inconsistency between use of the terms ''oil,'' ''sales oil,'' and ''stabilized oil'' in 40 CFR 98.233(j) and 40 CFR 98.236(j). The commenter stated that Onshore Petroleum and Natural Gas Gathering and Boosting facilities may process condensate but not oil, and the commenter asked the EPA to clarify how those terms should be applied to the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

Finally, the commenter noted that Calculation Method 1 for storage tanks requires use of the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category. The commenter stated that the term ''sub-basin'' has no relevance to the Onshore Petroleum and Natural Gas Gathering and Boosting segment because the composition of condensate processed at a compressor station may have little relationship to the oil or gas formation below the compressor station.

Response: The EPA agrees that the language in 40 CFR 98.233(j) and 40 CFR 98.236(j) should be clear for all Onshore Petroleum and Natural Gas Production facilities and all Onshore Petroleum and Natural Gas Gathering and Boosting facilities to which it applies. The existing definition of ''separator'' in 40 CFR 98.238 is a vessel in which streams of multiple phases are gravity separated into individual streams of single phase. This general definition and the general term ''gas-liquid separator'' apply to both Onshore Petroleum and Natural Gas Production facilities and all Onshore Petroleum and Natural Gas Gathering and Boosting facilities. Therefore, the EPA has reviewed the language and is amending references to a ''well,'' ''well pad,'' or ''wellhead,'' which are terms that are not expected to apply to most Onshore Petroleum and Natural Gas Gathering and Boosting facilities. The final provisions in 40 CFR 98.233(j) and 40 CFR 98.236(j) refer more generally to separators or gas-liquid separators. To address the comment that not all gathering and boosting system storage tanks receive liquids directly from separators, the EPA has amended 40 CFR 98.233(j)(1) and (2) to specify how those calculation methodologies may be used for Onshore Petroleum and Natural Gas Gathering and Boosting storage tanks receiving hydrocarbon liquids from non-separator equipment (*i.e.,* without a well or separator directly upstream of the storage tank).

Regarding the particular material being stored in storage tanks, the EPA agrees that there is inconsistency in some of the terms that could cause some confusion. The EPA is clarifying in this response that for the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the intent is for ''oil'' to refer more generally to hydrocarbon liquids, which is consistent with the statement in 40 CFR 98.233(j) that reporters are required to calculate emissions ''from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids.'' The proposed separate reporting requirements for quantity of produced oil throughput and produced condensate throughput in 40 CFR 98.236(aa)(10) have been revised, and the final rule requires reporting of the hydrocarbon liquids received by the facility and the hydrocarbon liquids leaving the facility. Finally, the EPA notes that the term ''sales oil'' is already defined in Subpart A to include ''produced crude oil or condensate,'' so there is no further clarification needed.

Regarding the term ''sub-basin,'' the EPA agrees with the commenter that the definition of ''sub-basin category, for onshore natural gas production'' in 40 CFR 98.238 is not relevant for Onshore Petroleum and Natural Gas Gathering and Boosting facilities. The EPA also agrees that the operations within a section of a gathering and boosting system may not be related to the formation type below the surface of the ground at that location, especially as the material travels further from the wells supplying gas and hydrocarbon liquids to the system. As a result of this comment, the EPA reviewed the use of the term ''sub-basin'' as it was proposed to apply to Onshore Petroleum and Natural Gas Gathering and Boosting facilities. In 40 CFR 98.233(j), the calculation methods provide options to estimate unknown parameters using information from a previous analysis of the composition in the sub-basin category. In these cases, the intent is to estimate unknown parameters from a representative unit (*e.g.,* well, separator). To reflect a similar intent for Onshore Petroleum and Natural Gas Gathering and Boosting facilities, 40 CFR 98.233(j)(1)(vii)(B) and 40 CFR 98.233(j)(1)(vii)(C) in Calculation Method 1 clarify that representative separators or non-separator equipment are located within the same county for Onshore Petroleum and Natural Gas Gathering and Boosting reporters. For Calculation Method 2, the term ''sub-basin category'' is used to describe calculation of emissions for flow to storage tanks directly from wells. The final rule includes a new paragraph 40 CFR 98.233(j)(2)(iii) to address calculation of emissions from flow to a tank from equipment other than a well or separator (such as a stabilizer or slug catcher), and this paragraph also clarifies that representative analyses should come from other non-separator equipment located within the same county. Finally, there are reporting requirements for a ''sub-basin ID'' in 40 CFR 98.236. The final rule specifies that for Onshore Petroleum and Natural Gas Gathering and Boosting, the information to be reported is the county in which the equipment is located.

5. Gathering Pipelines

a. Summary of Final Amendments

The EPA is finalizing the requirements for calculating emissions from gathering pipelines defined to be included in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as proposed. The methodology is similar to the approach used for equipment leaks in the Onshore Petroleum and Natural Gas Production segment. For gathering lines, reporters use the population count and emission factor approach in 40 CFR 98.233(r). The emission factors in Table W–1A for gathering pipelines are whole gas emission factors based on the U.S. GHG Inventory. The population count is the miles of gathering pipeline, similar to the approach used for calculating emissions from natural gas distribution pipelines in the Natural Gas Distribution segment. As noted in section II.B.1.a of this preamble, gathering pipelines with a GOR less than 300 scf/STB are not included in this segment.

b. Summary of Comments and Responses

Comment: One commenter asserted that the EPA should revise the proposed emission factor of 2.81 standard cubic feet (scf)/hour/mile for leaks from gathering pipelines to be based on characteristics of currently operating gathering pipelines rather than distribution pipelines or older data on gathering pipelines. The commenter also noted that this emission factor is not applicable to gathering pipelines that carry primarily liquids, as there is no gas stream until after separation. The commenter identified gathering pipeline-specific data from PHMSA and used the data to calculate a suggested emission factor of 2.23 scf/hour/mile.

Response: We reviewed the underlying data used to develop the proposed emission factor, and we agree with the commenter that the proposed emission factor could better account for differences between pipeline types and for currently operating gathering pipelines. In the 1996 Gas Research Institute (GRI)/EPA report that is the basis of the emission factor, material-specific emissions factors for gathering lines were developed using data from direct measurement of distribution pipelines conducted in the 1990s, not gathering pipelines. These material-specific emission factors are the same emission factors used by the commenter as the starting point for their revised emission factor.

We agree with the commenter that the emission factors should better represent currently operating gathering pipelines; however, there is significant variability in gathering pipelines and gathering system configurations. Owners and operators currently report the mileage of pipeline by gathering pipeline type to PHMSA.[7] Therefore, rather than calculate a single emission factor for gathering pipelines based on a distribution of gathering pipeline materials, as was done at proposal, the EPA determined that the most appropriate approach is to develop gathering pipeline emission factors for four pipeline material types: Protected steel, unprotected steel, plastic, and cast iron. (For more information about the development of these emission factors, see ''Greenhouse Gas Reporting Rule: Technical Support for Final 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831.) The final amendments require reporters to estimate emissions using material-specific emission factors provided in the rule and to report gathering pipeline mileage by material type.

The EPA also notes that reporters will not need to calculate emissions from gathering pipelines that carry hydrocarbon liquids if they are below the minimum GOR threshold for the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

6. Other Emission Sources

a. Summary of Final Amendments

The EPA is finalizing the requirements for natural gas pneumatic devices and pneumatic pumps located in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as proposed. Gathering and boosting reporters will use the same methods for calculating emissions as in the Onshore Petroleum and Natural Gas Production segment. The EPA is also finalizing the requirements for acid gas removal units, dehydrators, and flare stacks as proposed. The methods are the same as the methods for these sources in both the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment. The EPA is also finalizing the requirements for compressors and equipment leaks as proposed, with one clarification regarding how to count ''meters/piping'' for equipment leaks. Gathering and boosting reporters use the same method as in the Onshore Petroleum and Natural Gas Production segment. Specifically, a reporter will 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.

b. Summary of Comments and Responses

Comment: Two commenters stated that the major equipment categories for calculating equipment leaks by population count are not clear for the Onshore Petroleum and Natural Gas Gathering and Boosting segment. Both commenters requested that the EPA clarify how to count ''meters/piping'' for the Onshore Petroleum and Natural Gas Gathering and Boosting segment. One commenter also requested clarification regarding separators, compressors, and in-line heaters (specifically, whether small heating systems used to ensure a temperate environment for a meter are considered in-line heaters). The

[7] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. Natural and Other Gas Transmission and Gathering Pipeline Systems: Annual Report for Calendar Year. Form PHMSA F 7100.2–1 (rev 10–2014). OMB No. 2137–0522, Expires: 10/31/2016.

commenter also noted that there was limited time to evaluate the appropriateness of the emission factors in Table W–1A and the component counts in Table W–1B for gathering and boosting systems.

Response: The categories in Table W–1B represent the types of equipment that are generally expected to be found in the field for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities.[8] For the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA realizes that reporters will only use those categories that apply (*e.g.,* reporters will not include wellheads, as that equipment type is specific to Onshore Petroleum and Natural Gas Production facilities).

Most of the major equipment categories are described by function in the rule. For the example of a separator, 40 CFR 98.238 defines a separator as ''a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.'' Any device meeting this functional definition will fall into this major equipment category. Other major categories are described in the rule by their functional role, including dehydrators and compressors. For the in-line heater example for which the commenter requested clarification, the equipment described is not located in line with the fluid flow and therefore would not be considered in this equipment category.

The EPA agrees with both commenters that the measurement of meters/piping in the Onshore Petroleum and Natural Gas Gathering and Boosting segment was not clear as proposed. The final rule specifies that reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should count the number of meters in the facility and use that as the count for ''meters/piping.''

Comment: Two commenters supported the use of calculation methods that include emission factors for the Onshore Petroleum and Natural Gas Gathering and Boosting segment because they are less burdensome to the industry. However, the commenters also requested that the EPA allow reporters the option to use any available data/information that provides the best representation of emissions from their specific sources, including manufacturer data, test data, measurement and/or monitoring data. The commenters compared this option to the approach in state-level emissions inventories that require an emissions reporting hierarchy. The commenters noted that this approach will provide the EPA with more accurate emissions data that could be used to update the emission factors for the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

Response: The calculation methods provided in subpart W were selected to minimize burden on industry while maintaining the necessary quality and consistency of data to inform policy. Therefore, outside of the BAMM provisions being finalized in this rulemaking, the EPA does not agree to allow reporters to use customized, individual information for their emission sources at this time. The EPA is currently investigating additional calculation methods for subpart W sources and may propose additional calculation methods in the future.

C. Summary of Final Amendments for the Onshore Natural Gas Transmission Pipeline Segment

1. Summary of Final Amendments

The EPA is finalizing the proposal to add reporting requirements for emissions from natural gas transmission pipeline blowdowns between compressor stations in a new Onshore Natural Gas Transmission Pipeline segment. Commenters generally had no objections to the merit of including this segment in subpart W but did suggest technical edits and clarifications for targeted provisions. As noted in the preamble to the proposed amendments, a blowdown is the release of gas from transmission pipelines that causes a reduction in system pressure or a complete depressurization. The EPA is clarifying that for the purposes of the Onshore Natural Gas Transmission Pipeline segment, the blowdowns that must be reported are blowdowns of a pipeline or section of pipeline.

The EPA is finalizing clarifications to the proposed definition of onshore natural gas transmission pipeline owner or operator. For interstate pipelines, the onshore natural gas transmission pipeline owner or operator is 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, as proposed. For intrastate pipelines, the onshore natural gas transmission pipeline owner or operator is 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). If the intrastate pipeline is not subject to section 311 of the NGPA, the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers. Finally, the owner or operator of a pipeline that falls under the ''Hinshaw Exemption'' is the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224.

The EPA is finalizing the definition of facility for the new Onshore Natural Gas Transmission Pipeline segment as proposed; the facility is 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 owner or operator has multiple pipelines in the United States, the facility is considered the aggregate of those pipelines, even if they are not interconnected.

The EPA is finalizing the requirement that reporters use the methods in 40 CFR 98.233(i) to calculate or measure emissions from pipeline blowdown events as proposed. 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. 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 calculates both CH_4 and 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).

The EPA is not finalizing the proposed requirement to report the emissions and location (latitude and longitude) of each blowdown event. Instead, the EPA is requiring that Onshore Natural Gas Transmission Pipeline reporters report the total CH_4 and CO_2 emissions in each state, the number of blowdowns in each state, and the miles of pipeline in each state. In addition, instead of requiring Onshore Natural Gas Transmission Pipeline reporters to use the same equipment and event type categories as other industry segments reporting blowdown emissions, the EPA is including reporting categories specific to the Onshore Natural Gas Transmission Pipeline segment.

[8] See the memorandum ''Equipment-Level Population Emission Factors for Onshore Production,'' Docket Item No. EPA–HQ–OAR–2009–0923–3582, for more information regarding the derivation of this table.

2. Summary of Comments and Responses

Comment: Several commenters noted that not all intrastate pipelines are subject to section 311 of the NGPA and asked the EPA to clarify which intrastate pipelines are subject to reporting. One commenter requested that the EPA clarify that intrastate pipelines not subject to the NGPA are not required to report under subpart W. Another commenter suggested revising the definition of owner or operator to state that if section 311 of the NGPA does not apply, the intrastate transmission pipeline owner or operator is the owner or operator identified on required reports with the appropriate state agency.

Response: It was our intent to include transmission pipelines (including intrastate pipelines) that meet the already existing subpart W definition of ''transmission pipeline'' in the Onshore Natural Gas Transmission Pipeline segment. A transmission pipeline in subpart W is defined in 40 CFR 98.238 as a Federal Energy Regulatory Commission (FERC) rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the ''Hinshaw Exemption'' as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994). After reviewing the comments on the proposed rule, we re-reviewed section 311 of the NGPA and found that only operators of some intrastate pipelines, including those that transport natural gas on behalf of an interstate pipeline or sell natural gas to an interstate pipeline, are required to prepare a Statement of Operating Conditions for compliance under section 311 of the NGPA. Therefore, to clarify how to determine the owner and operator of intrastate transmission pipelines, the finalized definition of ''onshore natural gas transmission pipeline owner or operator'' specifies that for intrastate transmission pipelines not subject to section 311 of the NGPA, the owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers. The EPA also found that the proposed definition of ''onshore natural gas transmission pipeline owner or operator'' did not specify how to determine the owner or operator of pipelines that fall under the ''Hinshaw Exemption.'' The EPA notes that similar to intrastate pipelines, pipelines that fall under the ''Hinshaw Exemption'' must apply for a ''blanket certificate'' under 18 CFR 284.224 in order to transport petroleum or natural gas on behalf of interstate pipelines. Therefore, the finalized definition of ''onshore natural gas transmission pipeline owner or operator'' also specifies that for a pipeline that falls under the ''Hinshaw Exemption,'' the owner or operator is the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224.

Comment: Commenters appreciated that the EPA provided a threshold of 50 ft^3 of physical volume for blowdown emissions reporting but requested several changes. Commenters requested that the EPA include a list of ancillary equipment, such as metering and/or regulating stations, pipeline interconnects, and pig launchers and receivers, that would be excluded from reporting of blowdown emissions. One commenter suggested that, alternatively, the physical volume threshold could be increased to 3,000 thousand cubic feet to clearly exclude blowdowns of ancillary facilities along the pipeline. Another commenter stated that it is not feasible to establish a specific *de minimis* volume threshold to exclude all ancillary equipment.

Response: The EPA is finalizing the reporting threshold of 50 ft^3 of physical volume for blowdowns in the Onshore Natural Gas Transmission Pipeline segment as proposed. This threshold excludes smaller blowdown sources that have little contribution to emissions, consistent with other industry segments within subpart W that must report blowdown stack vent emissions. The EPA is not increasing the physical volume reporting threshold to account for blowdowns from ancillary equipment, as this would be inconsistent with the EPA's previous analysis in ''Equipment Threshold for Blowdowns'' (see Docket Item No. EPA–HQ–OAR–2009–0923–3581), and commenters were divided on whether increasing the threshold would even address their primary concern.

The EPA agrees that the emphasis for the Onshore Natural Gas Transmission Pipeline segment is on calculating and reporting blowdown emissions from pipeline segments, not ancillary equipment. However, any list of ancillary equipment that would be excluded from blowdown reporting could be incomplete, resulting in reporting of emissions from other equipment that is ancillary but not on the list in the rule. In addition, some of the equipment identified as ''ancillary'' in this segment is not considered ancillary in other industry segments, which could lead to confusion among reporters. Instead, the final rule clarifies that facilities in the Onshore Natural Gas Transmission Pipeline segment report pipeline blowdown emissions from blowdown vent stacks. If the blowdown does not include a pipeline segment or has a physical volume of less than 50 ft^3, then that blowdown is not required to be reported.

Comment: Several commenters stated that the blowdown equipment and event type categories in 40 CFR 98.233(i)(2) were developed for compressor station blowdowns and would not provide meaningful information regarding pipeline blowdowns in the Onshore Natural Gas Transmission Pipeline segment. The commenters provided suggestions for categories that would be more applicable to Onshore Natural Gas Transmission Pipeline blowdowns and would provide more valuable information than relying on the categories in the existing rule.

Response: The EPA agrees with the commenters that the rule should include blowdown categories specific to blowdowns in the Onshore Natural Gas Transmission Pipeline segment. The final rule specifies that blowdowns must be grouped into one of the following categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined by PHMSA, and all other pipeline segments with a physical volume greater than or equal to 50 ft^3.

Comment: Commenters requested that the EPA not finalize the requirement to report latitude and longitude for each blowdown event. The commenters indicated this requirement would be burdensome, such data are not currently collected, the requirement is inconsistent with the Paperwork Reduction Act, and the data would not be useful in determining the inventory. Some commenters also suggested aggregating emissions at the state level or only at the national/facility level.

Response: The requirement to report latitude and longitude of each blowdown was included in the proposed rule to help characterize the emissions from the new Onshore Natural Gas Transmission Pipeline segment on a more granular level than the nationwide facility. The EPA evaluated this comment and has noted the commenters' assertion that the latitude and longitude of each blowdown is not information currently reported elsewhere and may result in additional burden. Therefore, the EPA is not finalizing the requirement to report the emissions or latitude and longitude for each individual blowdown. Instead, the EPA is finalizing requirements for reporters to aggregate blowdown emissions by state and report the number of blowdowns and mileage of pipeline per state.

Comment: Two commenters questioned the requirement to report the data elements in proposed 40 CFR 98.236(aa)(11). Two commenters noted that the quantities of natural gas in this section are duplicative of information reported to FERC annually in FERC Form 2, although the units of measure are dekatherms rather than thousand standard cubic feet. One commenter noted that for the GHGRP reporting, they would assume 1 dekatherm is equivalent to 1,000 scf of natural gas, based on the approximate heat value of natural gas. The other commenter opposed these reporting requirements because they are duplicative and inconsistent with the requirements of the PRA, which is intended to reduce the information burden imposed by the federal government by requiring that agencies ensure that reported information is not duplicative of other available data and has a practical utility. This commenter stated that the EPA has not followed the PRA. The commenter also stated that the requested information is irrelevant to assisting EPA in verifying pipeline blowdown emissions; in particular, the information cannot be used to calculate pipeline blowdown volumes.

Response: As the EPA has noted elsewhere, the data collected in the GHGRP will be used to inform future policy decisions. As such, information regarding emissions and the inputs needed to verify those emissions is only part of the information that is needed. It is important to understand that, to inform future policy, activity data is often as useful as emissions estimates. The EPA has determined that data elements in 40 CFR 98.236(aa)(11) are activity data that will be used to determine how to use the emissions data to inform future policy decisions. It is essential that reporters provide and certify the data they gather under this rule so that EPA has a complete inventory from all sources under this rule and can directly relate the activity data to the emissions data reported, which will provide for appropriate verification of the emissions data reported.

The EPA agrees with the first commenter that for purposes of reporting the data elements in 40 CFR 98.236(aa)(11), reporters may consider 1 dekatherm equal to 1,000 scf.

Comment: Several commenters asserted that the EPA has not been consistent in its decisions on whether to include pipeline leaks across the subpart W industry segments. Some commenters supported the EPA's proposal not to include leaks from transmission pipelines and noted the decision was consistent with the Onshore Petroleum and Natural Gas Production segment. Conversely, one commenter stated that transmission pipeline leaks should be reported, consistent with the new Onshore Petroleum and Natural Gas Gathering and Boosting segment. This commenter noted that accidental leaks at these facilities can be a significant source of CH_4 emissions, as evidenced by the magnitude of emissions from pipeline incidents reported to PHMSA, and leaks at remote locations may not be noticed or repaired immediately.

Response: 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 noted in the proposal preamble for these amendments (79 FR 76267; December 9, 2014) that larger fugitive leaks are currently reported to PHMSA as part of 49 CFR 191.3. Under this provision, any pipeline incident that results in unintentional gas loss of 3 million ft^3 or more must be reported. The commenter that noted that emissions can be significant cited the emissions reported to PHMSA under this provision, and the EPA does not find it necessary to require owners and operators to report this same information under the GHGRP. The focus of the PHMSA reporting requirements is to identify major safety-related incidents that are not a part of typical operations. Therefore, the EPA is not finalizing a requirement to report fugitive emissions from transmission pipeline leaks but will continue to review this source as part of the EPA's ongoing effort to ensure comprehensive, high quality data in subpart W.

D. Summary of Final Amendments for Well Identification Numbers

1. Summary of Final Amendments

The EPA is finalizing some of the proposed amendments to 40 CFR 98.236 to add reporting requirements for well identification numbers to improve data quality by enabling identification of wells. These well identification numbers will be reported for the first time in the report covering 2016 emissions; reporters will not be required to report well identification numbers for previous years. 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).[9] For any well that does not already have a US Well Number, the reporter will be required to provide the unique well number assigned by the permitting authority for drilling of oil and gas wells. Commenters varied in their level of support for the proposed provisions regarding well identification numbers. The EPA is adjusting the final provisions in response to concerns about these reporting provisions raised in comments.

The EPA is requiring the reporting of well identification numbers for the Onshore Petroleum and Natural Gas Production segment only for information related specifically to wells. 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 report must include the well identification number for which those measurements were made and the well identification number(s) of other wells to which the measurements will be applied. This includes a list of the well identification numbers by sub-basin for the producing wells at the end of the calendar year as well as lists of the well identification numbers for the wells acquired, divested, completed, and permanently taken out of production during the calendar year. The EPA is not finalizing the proposed requirement that reporters in the Onshore Petroleum and Natural Gas Production segment report a list of well identification numbers associated with different emission

[9] 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.*

sources for all wells in a sub-basin included in the reported emissions data.

The EPA is finalizing the proposed change to update references to the ''API well number'' in subpart W to ''well identification number.'' The EPA is not otherwise changing the well identification reporting requirements finalized in 2014 (79 FR 70352; November 25, 2014). Reporters will still need to report well identification numbers for liquids unloading and for any exploratory wells for which reporting has been delayed for 2 years.

2. Summary of Comments and Responses

Comment: While one commenter supported the addition of well identification number reporting, most commenters opposed the proposal to require reporting of well identification numbers. These commenters asserted that requiring reporting of well identification numbers is an overreach of the EPA's authority for the reporting program under CAA section 114 and that the EPA has not provided a reasoned basis for the departure from the previous EPA approach that well-specific data was not necessary under Subpart W. Commenters also noted that well identification numbers are not needed to validate reported emissions. One commenter noted that the EPA has not questioned the data collected from wells thus far; nor has the EPA stated that the data already collected are insufficient to inform policy without addition of well identification numbers, so with this proposal, the EPA is no longer balancing data collection with reporting burdens. Commenters stated that mapping and maintaining a database of well identification numbers is more burdensome than the EPA estimated, and one commenter stated that it would be arbitrary and capricious to require companies to expend the resources necessary to report these data. Commenters also noted that it is not clear how to interpret the term ''associated with'' in all cases. One commenter stated that matching specific wells with emissions in the GHGRP could cause security concerns.

Response: The EPA disagrees that requiring reporting of well identification numbers is an overreach of our authority. The EPA has determined that these data elements are useful and necessary for the verification of existing data and for characterizing the emissions from the industry segment. This final revision will allow the EPA to link the GHGRP data to other databases (*i.e.* state permitting 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. Additionally, being able to match the GHGRP data to other data sources will 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 will 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. The EPA reiterates that CAA section 114 provides the EPA with the authority to collect emissions data, which includes information about the location of the source of emissions. Section 114 generally authorizes the EPA to gather information from any person who owns or operates an emissions source, who is subject to a requirement of the CAA, who manufactures control or process equipment, or who the Administrator believes has information necessary for the purposes of section 114(a). The EPA may gather information for purposes of establishing implementation plans or emissions standards, determining compliance, or ''carrying out any provision'' of the CAA. For these reasons, the Administrator may request that a person, on a one-time, periodic or continuous basis, establish and maintain records, make reports, install and operate monitoring equipment and, among other things, provide such information the Administrator may reasonably require. This language has been interpreted to grant the EPA broad authority. See, *e.g.,* Dow Chemical Co. v. U.S., 467 U.S. 227, 233 (1986) (''Regulatory and enforcement authority generally carries with it all modes of inquiring and investigation traditionally employed or useful to execute the authority granted.''). See, generally *Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Volume No.: 9, Legal Issues* (Docket Item No. EPA–HQ–OAR–2008–0508–2264). The requirement to report well identification numbers for well-specific data clearly fits within EPA's statutory authority. We also believe, for the reasons stated above, that we are exercising this authority reasonably in furtherance of the purposes of the Clean Air Act. Further, the EPA disagrees that this is a deviation from our previous approach to collecting data. As discussed in section II.B of this preamble, the EPA is finalizing the requirement to report Onshore Petroleum and Natural Gas Gathering and Boosting facilities at the basin-level, which is consistent with our previous approach to the Onshore Petroleum and Natural Gas Production segment.

Therefore, the EPA is finalizing the requirements to report the well identification number for well-specific data as proposed. Specifically, 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 or operations associated with individual wells (*e.g.,* if Equation W–10A is used to calculate emissions from oil well completions and workovers with hydraulic fracturing, well testing emissions, liquids unloading), the report must include the well identification number for which those measurements were made, or for which the equipment or operations are associated. In addition, the EPA is finalizing the requirements in 40 CFR 98.236(aa)(1)(ii)(D) through (H) to include a list of the well identification numbers by sub-basin for the producing wells at the end of the calendar year and lists of the well identification numbers for the wells acquired, divested, completed, and permanently taken out of production during the calendar year. The EPA continues to expect that this is a low burden to reporters because reporters already track and maintain well identification numbers associated with measurements used for the GHGRP input data.

To respond to the comment that well identification numbers may not be available for or assigned to equipment other than wells, the EPA reviewed the permits and requirements in seven different states. Although most of the states assign unique identifiers to each emission source, the EPA found that only two of the seven states have a tracking system that links individual emission sources to specific wells and well identification numbers, and these two states are not consistent in their approach. (See ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule'' in Docket ID No. EPA–HQ–OAR–2014–0831 for more information on this analysis.) While it may be straightforward to assign some emission sources directly to one well, particularly if there is only one well on the single well pad and the reporter does not operate any other wells nearby, the EPA's review of state requirements shows that there may be multiple scenarios in which a reporter does not know which well or wells are associated with a particular emission source. For example, there may be multiple wells on a single well pad and multiple storage tanks associated with that well pad, and the tanks may have the ability to receive hydrocarbon liquids from several of those wells. Therefore, in light of the potential burden of requiring facilities to develop new tracking systems that would assign and track emissions to well identification numbers for the purposes of part 98, the EPA is not requiring facilities in this rulemaking to report well identification numbers for every emission source in a facility in the Onshore Petroleum and Natural Gas Production segment.

E. Summary of Final Amendments to Best Available Monitoring Methods

1. Summary of Final Amendments

As proposed, reporters will be allowed to use BAMM for the 2016 reporting year for the new industry segments and emission sources included in this action. 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. Reporters are allowed to use BAMM to estimate inputs to emission equations for the newly finalized emission sources for cases where the monitoring of these inputs would not be possible beginning on January 1, 2016. The use of BAMM is not allowed for the reporting of well identification numbers because reporters should already have well identification numbers readily available for all wells and associated equipment to which this reporting requirement applies and because the well identification number is not a parameter that requires monitoring equipment to be measured and, therefore, does not meet the requirements for BAMM.

For these sources, the EPA is finalizing a longer timeline for BAMM than was proposed. Reporters have the option of using BAMM for the new industry segments and emission sources included in this action from January 1, 2016, to December 31, 2016, without seeking prior EPA approval. The provision providing a set amount of automatic transitional BAMM will allow reporters to prepare for data collection while automatically being able to use BAMM, which is consistent with the approach of prior part 98 rulemakings. This additional time for reporters to comply with the revised monitoring methods in subpart W will allow facilities to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions, and is responsive to comments received on the proposed rule provisions.

The EPA is not finalizing the proposed provision to allow reporters the opportunity to request an extension for the use of BAMM. The EPA will not accept requests for an extension for the use of BAMM beyond the time periods listed above. As proposed, the EPA also is not providing transitional BAMM for these new requirements beyond December 31, 2016.

The EPA is not allowing the use of BAMM beyond 2016 and does not anticipate that BAMM will be needed beyond 2016 for the new segments and emissions sources being finalized in this rule.

2. Summary of Comments and Responses

Comment: Several commenters stated that only 3 months of automatic BAMM and 1 year of transitional BAMM is not enough time to implement the monitoring and measurement requirements for facilities newly subject to subpart W and newly added emission sources. The commenter stated that adding a new segment is a significant amendment and the EPA has set the precedent of providing at least 1 year of automatic BAMM when adding a new segment to subpart W. The commenters noted that not all gathering and boosting reporters are already reporting as Onshore Petroleum and Natural Gas Production facilities, so they will not necessarily all be familiar with the monitoring and calculation methodologies. The commenters also noted that nearly all reporters will be spending the first month working on BAMM requests for the rest of 2016.

The commenters had a variety of suggestions for how long the EPA should provide BAMM for these new emission sources. Several commenters suggested 1 year (through the end of 2016) for automatic BAMM. Another commenter suggested March 31, 2017 (*i.e.,* 1 year in addition to the EPA's proposed 3 months), and another stated that 3 years would be consistent with the length of time provided when the Onshore Petroleum and Natural Gas Production segment was added to subpart W. Some commenters addressed the length of transitional BAMM with the EPA's approval. One commenter noted that a new reporter/facility could become subject to one of the new segments beyond the end of 2016, so there should be no deadline for submitting a request for BAMM to the EPA. Another requested transitional BAMM through the end of 2018.

Response: The EPA recognizes that most of the amendments being finalized in this rulemaking are new requirements rather than clarifications of existing reporting requirements for facilities already subject to subpart W and may require the development and implementation of new systems of data collection and monitoring. Therefore, the EPA is finalizing 1 year of automatic transitional BAMM in place of the proposed 3 months of automatic transitional BAMM. This additional time for reporters to comply with the revised monitoring methods in subpart W will allow facilities to install the necessary monitoring equipment and implement any new systems of data collection that may be required. Because the amount of time for which automatic BAMM is available should be sufficient time to comply with the requirements of subpart W for the new segments and emission sources, the EPA will not provide additional BAMM beyond the automatic BAMM provisions in 40 CFR 98.234(g).

We note that 40 CFR 98.235(e) and(f) provides 6 months of reporting flexibility for facilities that become subject to subpart W or acquire new sources after reporting year 2016. Reporters may also refer to the provisions of 40 CFR 98.235 after reporting year 2016 for guidance on reporting emissions if certain required data are not collected.

III. Confidentiality Determinations

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

In the proposed rule, we assigned 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.[10] For data elements the EPA assigned to a direct emitter category with a categorical determination, the EPA proposed that the categorical determination for the category be applied to the proposed new data element. For data elements assigned to the ''Unit/Process 'Static' Characteristics that Are Not Inputs to Emission Equations'' and ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' we proposed confidentiality determinations on a case-by-case basis taking into

[10] ''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'' (76 FR 30782, May 26, 2011).

consideration the criteria in 40 CFR 2.208, consistent with the approach used for data elements previously assigned to these two data categories. We also proposed individual confidentiality determinations for six new data elements without making a data category assignment. Refer to the preamble to the proposed rule (79 FR 76267; December 9, 2014) for additional information regarding the proposed confidentiality determinations.

With consideration of the data provided by commenters, the EPA is finalizing the confidentiality determinations as proposed. Specifically, the EPA is finalizing the proposed decision to require each of the new data elements to be designated as ''not CBI.''

The EPA proposed to provide reporters with the option to delay reporting of five data elements for 2 reporting years in situations where exploratory wells are the only wells in a sub-basin. We received comment requesting that the EPA provide the same 2-year delay for additional data elements associated with exploratory wells. The comment and the EPA's response are included in section III.B of this preamble. Based on consideration of the comment and consistent with the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014), the EPA is finalizing provisions to provide reporters with the option to delay reporting of five data elements as proposed and, based on comments received, an additional two data elements for 2 reporting years in situations where exploratory wells are the only wells in a sub-basin. For a given sub-basin, in situations where wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the required measurement, the following seven data elements associated with the delineation or wildcat well may be delayed for 2 reporting years: (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 (40 CFR 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 (40 CFR 98.236(g)(5)(i)); (3) the measured flowback rate, in standard cubic feet per hour, for each sub-basin (40 CFR 98.236(g)(5)(ii)); (4) the gas to oil ratio for the well (40 CFR 98.236(g)(5)(iii)(A)); (5) the volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing (40 CFR 98.236(g)(5)(iii)(B)); (6) the total annual gas-liquid separator oil volume that is sent to applicable onshore storage tanks, in barrels (40 CFR 98.236(j)(1)(iii)); and (7) the total annual oil throughput that is sent to all atmospheric tanks, in barrels (40 CFR 98.236(j)(2)(i)(A).

Four of the seven data elements for which reporting may be delayed by 2 years are inputs to emission equations and the EPA provided the same option in the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014). Two of the seven data elements are inputs only when the applicable data are related to a single well (the two data elements in 40 CFR 98.236(g)(5)(i)), and one data element is never an input (40 CFR 98.236(j)(2)(i)(A)). Where the EPA agrees that there are early disclosure concerns related to exploratory wells, the EPA decided to treat those early disclosure concerns consistently throughout subpart W by providing the option to delay reporting by 2 years to all seven data elements listed above.

At proposal, in cases where the two data elements in 40 CFR 98.236(g)(5)(i)) are not inputs to equations, they were assigned to the ''Unit/Process Operating Characteristics that are Not Inputs to Emission Equations'' category and were proposed to be ''not CBI.'' The EPA is finalizing this determination as proposed. Specifically, the ''not CBI'' determination applies to all situations except for when the data elements are inputs to equations.

For the situations when the data elements are used as inputs to equations, the EPA is assigning them to the ''Inputs to Emission Equations'' data category and is not making confidentiality determinations for these data. The EPA evaluated and summarized any potential disclosure concerns with the reporting of the data elements assigned to the ''Inputs to Emission Equations'' data category in the memo titled ''Review for Potential Disclosure Concerns for Inputs to Emission Equations Affected by the 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' available in Docket ID No. EPA–HQ–OAR–2014–0831. Other than the exception of the early disclosure concerns for certain data elements related to exploratory wells discussed earlier in this section, the EPA has concluded that there are no disclosure concerns with the reporting of these data elements.

The data element collected under 40 CFR 98.236(j)(2)(i)(A) was proposed as ''not CBI'' and was not assigned to a data category. The EPA is finalizing this determination as proposed as well. For the data elements reported under 40 CFR 98.236(g)(5)(i)) (in cases where they are not inputs to equations) and 40 CFR 98.236(j)(2)(i)(A), the ''not CBI'' determinations will apply once the data are reported to the EPA following the 2-year delay.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed categorical assignments and confidentiality determinations. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and responses. See the memorandum ''Final Data Category Assignments and Confidentiality Determinations for Data Elements (excluding inputs to emission equations) in the 'Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of final data category assignments and confidentiality determinations, and a discussion of changes since proposal.

Comment: One commenter requested that the EPA reconsider the determination that the quantity of produced gas throughput in the calendar year and the quantity of produced gas consumed by the facility in the calendar year are ''not CBI.'' The commenter noted that the quantity of natural gas received and the quantity of processed gas leaving processing plants was maintained as CBI in the 2014 amendments (79 FR 70352; November 25, 2014). The commenter also stated that information on fuel consumed at gathering and boosting facilities is not typically publically available, and when this information is combined with the quantity of produced gas throughput, it directly indicates the fuel efficiency of a station. The commenter noted that while the EPA is correct that the agreements are long-term for a given well, revealing information about one facility's fuel efficiency could cause competitive harm by affecting contracts for other facilities owned by that company, especially if there are smaller gathering and boosting facilities in the area that do not have to report this information to the GHGRP.

The commenter also requested that the EPA clarify a number of the reporting elements in 40 CFR

98.236(aa)(10). Specifically, the commenter requested clarification of the terms ''produced gas,'' ''produced condensate,'' ''produced oil,'' ''throughput,'' and ''consumed'' as they are used in proposed 40 CFR 98.236(aa)(10). The commenter also asserted that the data element in 40 CFR 98.236(aa)(10)(ii) (''quantity of produced gas consumed'') would be redundant with subpart C and should not be finalized. Finally, the commenter stated that the requirement to report the ''quantity of gas flared, vented and/or unaccounted for in the calendar year'' in 40 CFR 98.236(10)(aa)(v) would undermine over 5 years of rule development, public comment, reconsiderations, and petitioner negotiations because it would require reporting of emissions that are otherwise exempted (*e.g.,* blowdowns below 50 ft^3).

Response: The EPA reviewed these comments and has clarified the reporting elements in 40 CFR 98.236(aa)(10) for the final rule. The final reporting requirements include: (1) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet; (2) the quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet; (3) the quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels; and (4) the quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels. The EPA has determined that these quantities will be easily accessible for all reporters and are more consistent with the reporting requirements for the Onshore Natural Gas Processing segment. The EPA is finalizing the CBI determinations for these quantities as ''not CBI,'' as proposed.

The final reporting requirements do not include the terms ''produced gas,'' ''produced condensate,'' ''produced oil,'' ''throughput,'' or ''consumed,'' so no clarification regarding the use of those terms is needed. In particular, the final rule does not include a requirement to report the quantity of produced gas consumed by the facility. The difference between the quantities received by a gathering and boosting facility and the quantities exiting the gathering and boosting facility is expected to include the quantity of gas consumed by the facility as well as the quantity of gas flared or vented in one lump sum. Therefore, the reporting requirements do not directly indicate the fuel efficiency of the stations in a gathering and boosting facility.

Comment: One commenter reiterated previously stated concerns over the disclosure of information for exploratory wells, especially when they are located in stepout areas where no prior reporting exists for a given sub-basin. The commenter supported the EPA's proposal to defer reporting of data elements related to oil well completions and workovers with hydraulic fracturing for exploratory wells, but expressed concern that EPA has not provided such a delay in reporting for all emissions data and data elements that are associated with exploratory wells. Specifically, the commenter stated that the EPA failed to provide a necessary 2-year deferral in reporting for the following data elements, which are as business sensitive and confidential as the other information for which the EPA proposed to defer reporting for 2 years:

- 40 CFR 98.236(g)(5)(iii)(A)—If you used Equation W–12C to calculate the average gas production rate for an oil well, the gas to oil ratio for the well in standard cubic feet of gas per barrel of oil.
- 40 CFR 98.236(g)(5)(iii)(B)—If you used Equation W–12C to calculate the average gas production rate for an oil well, the 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.
- 40 CFR 98.236(g)(6)(i)—If you used Equation W–10B to calculate annual volumetric total gas emissions for completions that vent gas to the atmosphere, the vented natural gas volume, in standard cubic feet, for each well in the sub-basin.
- 40 CFR 98.236(g)(6)(ii)—If you used Equation W–10B to calculate annual volumetric total gas emissions for completions that vent gas to the atmosphere, the flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin.
- 40 CFR 98.236(g)(7)—For each oil well completion or workover and well type combination, annual gas emissions.
- 40 CFR 98.236(g)(8)—For each oil well completion or workover and well type combination, annual CO_2 emissions.
- 40 CFR 98.236(g)(9)—For each oil well completion or workover and well type combination, annual CH_4 emissions.
- 40 CFR 98.236(g)(10)—For each oil well completion or workover and well type combination, the total N_2O emissions, if the well emissions were vented to a flare.

Response: The EPA reviewed the data elements identified by the commenter as having disclosure concerns for exploratory wells (delineation wells and wildcat wells). Consistent with the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014), the EPA has determined that, for gas well completions or workovers with hydraulic fracturing of wildcat wells and/or delineation wells, early public disclosure of some of the additional data elements identified by the commenter could reveal the well productivity of wildcat wells and/or delineation wells, thereby resulting in the loss of investment value.

The additional data elements that could reveal well productivity for wildcat and/or delineation wells are as follows:

- The gas to oil ratio for the well (40 CFR 98.236(g)(5)(iii)(A))
- The volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing (40 CFR 98.236(g)(5)(iii)(B))

As the EPA has previously noted (79 FR 70352, November 25, 2014), in the interim period before these data are reported to the EPA, the EPA will be able to verify the majority of the emissions using data elements that will be reported to the EPA. For the seven total data elements that may be delayed for 2 years, the EPA will verify emissions using other data reported to the EPA, and will conclude verification upon receipt of the data. The EPA agrees with the commenter that a 2-year delay of reporting is sufficient to prevent early public disclosure of these data and will provide sufficient time for the reporter to thoroughly conduct an assessment of the well. Given the results of this evaluation, the EPA determined that, for these data elements, in those cases where delineation wells or wildcat wells are the only wells in a sub-basin, reporters should be provided an option to delay reporting of the given data element for 2 reporting years starting in 2015. In such cases, if the 2-year delay in reporting is used, the reporter must indicate for each delayed reporting element that wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the measurement in the current reporting year. In addition, when reporters report the delayed data elements after the 2-year delay, they must also report the well identification numbers for the applicable wildcat and/or delineation wells in the sub-basin for which the reporting element was delayed. For example, if a delineation or wildcat well is completed in 2015 in a sub-basin that has only delineation or wildcat wells or these are the only wells for which measurements can be made, then the reporter may: (1) Elect to report these seven data elements in their 2016 annual report submitted by March 31, 2017, or (2) elect to delay reporting of these data elements for up to 2 years. If the reporter elects to delay reporting, then the well identification numbers for the wildcat and delineation wells in the sub-basin for which reporting has been delayed and the data elements delayed from reporting must be reported no later than March 31, 2019.

The following inputs meet the definition of emission data in 40 CFR 2.301(a)(2)(i) because they indicate the amount or frequency of gas emitted by the facility: Volume of natural gas vented (reported under 40 CFR 98.236(g)(6)(i)) and flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation (reported under 40 CFR 98.236(g)(6)(ii)). Without corresponding activity data, such as a count of the exploratory wells in a sub-basin or production or flow rate data for a sub-basin containing only exploratory wells, there is no potential to disclose business sensitive information based on these data elements. Therefore, the EPA is not providing an option to delay reporting of these data elements for 2 reporting years.

Similarly, the data element annual gas emissions (reported under 40 CFR 98.236(g)(7)) meets the definition of emission data in 40 CFR 2.301(a)(2)(i) and is assigned to the ''Emissions'' data category because it indicates the amount of gas emitted by the facility. In addition, the following data elements meet the definition of emission data in 40 CFR 2.301(a)(2)(i) and are assigned to the ''Emissions'' data category because they are emissions of pollutants emitted by the source: annual CO_2 emissions (reported under 40 CFR 98.236(g)(8)), annual CH_4 emissions (reported under 40 CFR 98.236(g)(9)), and annual nitrous oxide (N_2O) emissions if the well emissions were vented to a flare (reported under 40 CFR 98.236(g)(10)). For these data elements that are assigned to the ''Emissions'' data category, the commenter did not claim or provide any justification for why these data elements do not meet the definition of emission data. Without corresponding activity data, such as a count of the exploratory wells in a sub-basin or production or flow rate data for a sub-basin containing only exploratory wells, there is no potential to disclose business sensitive information based on these data elements. Therefore, the EPA is not providing an option to delay reporting of these data elements for 2 reporting years.

IV. Impacts of the Final Amendments to Subpart W

A. Impacts of the Final Amendments

The final amendments to subpart W 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. The EPA is adding 213 new data elements to the reporting requirements. The new data elements impose additional burden and costs because, for each of the new data elements that are required to be reported, reporters are required to calculate the data element using readily available data and report the value to the EPA via e-GGRT as part of the annual report currently required under part 98.

The EPA calculated the increase in reporting and recordkeeping burden associated with the new data elements by adjusting labor hours upwards per reporter for all affected industry segments. For all three segments, an estimate of 10 hours per year per reporter was allotted for reporting via e-GGRT and 10 hours per year per reporter was allotted for recordkeeping.

Costs to reporters associated with this rulemaking are expressed as labor costs (*i.e.,* the cost of labor by facility staff to comply with the amendments), capital costs for equipment and travel, and operation and maintenance (O&M) costs.

Reporters in the Onshore Petroleum and Natural Gas Production segment have to monitor and report emissions and data elements associated with oil well completions and workovers with hydraulic fracturing. Reporters in this segment also have to report the well identification numbers 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 count towards determining applicability under subpart W. The 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. These numbers have not changed from proposal.

The 50 new reporters will be required to estimate and report emissions data and related data elements associated with several different emission sources within this new industry segment, including acid gas removal units, associated natural gas venting and flaring, storage tanks, dehydrators, equipment leaks, liquids unloading, and pneumatic devices.

Reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment must estimate and report emissions data and related data elements associated with several different emission sources within this new industry segment, including acid gas removal units, storage tanks, blowdown vents, dehydrators, equipment leaks, flare stacks, and pneumatic devices. Approximately 200 new reporters are expected to be subject to subpart W due to the amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in this rulemaking. This number has not changed from proposal.

Reporters in the Onshore Natural Gas Transmission Pipeline segment will need to estimate and report emissions data and related data elements associated with transmission pipeline blowdown activities. Approximately 183 new reporters in this segment are expected to be subject to subpart W. This number increased from 150 to 183 since proposal due to public comment.

The EPA received multiple comments regarding the impacts of the proposed amendments. After evaluating these comments and reviewing other changes from proposal, the EPA revised the impacts assessment slightly from proposal. The final amendments to subpart W are not expected to significantly change the burden calculated at proposal.

The EPA has determined that the cost associated with this final action will be $7,190,235 each year and has worked to minimize burden to reporters where practicable. See the memorandum, ''Assessment of Impacts of the 2015 Final Revisions to Subpart W'' in Docket ID No. EPA–HQ–OAR–2014–0831 for additional information.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the impacts of the proposed amendments to subpart W of part 98. We note that numerous commenters asserted that the burden was underestimated, and some provided suggestions for improvement, but most of those comments did not include the detailed information the EPA needed to assess the comment fully, such as a suggestion for a revised burden estimate, support for the suggestion, and an explanation of why the suggested value is representative of all sources subject to the same requirements. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and responses.

Comment: One commenter asked for an explanation for the estimate of 200 respondents in the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The commenter noted that the EPA estimated the number of reporters in the Onshore Natural Gas Processing industry segment as 291 reporters. The commenter stated by the nature of the industry, any company with a processing plant will most likely also have an associated gathering system subject to reporting and suggested that the number of reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment should total 291, at minimum, but potentially more.

Response: Due to differences in the definitions of the two industry segments, the EPA disagrees that the number of reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should match the number of reporters in the Onshore Natural Gas Processing segment. The EPA estimate of 200 respondents was based on the regulatory analysis for Office of Pipeline Safety (OPS) safety regulations. In the analysis, it was estimated that 50 percent of the 400 natural gas gathering pipeline operators under regulation are small entities operating small diameter, low pressure (Type B) gathering lines and fifty percent are large diameter, high pressure lines (Type A) potentially subject to the safety regulation (depending upon proximity to population centers).[11]

Comment: One commenter noted that the EPA estimated that there are 150 reporters for Onshore Natural Gas Transmission Pipeline facilities at proposal. However, the commenter stated that the EPA should expect 183 reporters in the segment based on the number of operators that are required to complete a PHMSA annual report (PHMSA F–7100–2) or are regulated by FERC under section 311 of the NGPA.

Response: The EPA agrees with the suggested change. The preamble to the final amendments, the final Supporting Statement, and the memorandum ''Assessment of Impacts of the 2015 Final Revisions to Subpart W'' (see Docket ID No. EPA–HQ–OAR–2014–0831) have been updated to reflect the change from 150 reporters to 183 reporters in the Onshore Natural Gas Transmission Pipeline segment.

Comment: Two commenters objected to the collection of well identification numbers. One commenter noted that collection would require significant resources and would be unduly burdensome on operators. The other commenter stated that the burdens associated with collecting and reporting this data far outweigh any minimal benefits in data quality.

Response: The EPA is finalizing the well identification number reporting requirements for well-specific data as proposed, but the EPA is not requiring well identification numbers to be reported in this rulemaking for equipment other than wells. See section II.D of this preamble for additional discussion responding to this comment.

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 and was therefore not submitted to the Office of Management and Budget (OMB) for review.

In addition, the EPA prepared an analysis of the potential costs associated with the final amendments to subpart W. This analysis is contained in the memorandum ''Assessment of Impacts of the 2015 Final Revisions to Subpart W.'' A copy of the analysis is available in the docket for this action (see Docket ID No. EPA–HQ–OAR–2014–0831) and the analysis is briefly summarized in section IV of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2300.16. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This action adds 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. Data collection complements the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) and provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments. The data can be used to complement atmospheric GHG studies and inform updates to emission inventories. Various activity data are collected that can be used to improve understanding of the occurrence of emissions from a variety of sources.

Data collected must be made available to the public unless the data qualify for CBI treatment under the CAA and EPA regulations. All data determined by the EPA to be CBI are safeguarded in accordance with regulations in 40 CFR chapter 1, part 2, subpart B.

Respondents/Affected Entities: The respondents in this information collection include owners and operators of petroleum and natural gas systems facilities that must report their GHG emissions to the EPA to comply with subpart W of part 98.

Respondent's Obligation To Respond: The respondent's obligation to respond is mandatory under the authority provided in CAA section 114.

Estimated Number of Respondents: Approximately 3,300 respondents per year.

Frequency of Response: Annual.

Total Estimated Burden: 317,100 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total Estimated Cost: $29.2 million (per year), includes $1.1 million annualized capital and 2.8 million operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities

[11] U.S. Department of Transportation. Pipeline and Hazardous Materials Safety Administration. *Draft Regulatory Evaluation, Regulated Natural Gas Gathering Lines, Regulatory Analysis,* Docket RSPA–1998–4868. Available at *www.viadata.com/pipeliner/library_docs/Gatheringanalysis.pdf.*

subject to the requirements of this action are: (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.

The Agency has determined that a few small businesses may experience an insignificant impact. Details of this analysis are presented in section IV.B of the preamble to the proposed amendments (79 FR 76267; December 9, 2014).

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

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

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

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This regulation will apply directly to petroleum and natural gas facilities that emit GHGs. Although few facilities that will be subject to the rule are likely to be owned by tribal governments, the EPA has sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final subpart W that was promulgated on November 30, 2010 (75 FR 74458).

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in section IV.F of the preamble to the re-proposal of subpart W published on April 12, 2010 (75 FR 18608), and section IV.F of the preamble to the subpart W 2010 final rule published on November 30, 2010 (75 FR 74458).

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks, that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risks.

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

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

The EPA believes the human health or environmental risk addressed by this action will **not** have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because it does not affect the level of protection provided to human health or the environment. Instead, this rule addresses information collection and reporting procedures.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 98

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

Dated: October 1, 2015.

Gina McCarthy,

Administrator.

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

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 1. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401, *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 petroleum and/or natural 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. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR) less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil

here refers to hydrocarbon liquids of all API gravities).

(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 § 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 § 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 § 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 paragraphs (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 that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

* * * * *

(8) Well venting during well workovers with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

* * * * *

(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 pipeline blowdown 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 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 paragraph (i)(2) introductory text;
■ n. Revising the parameters ‘‘T_a’’ and ‘‘P_a’’ of Equation W–14A in paragraph (i)(2)(i);
■ o. Revising paragraphs (j) introductory text, (j)(1) through (3), and (j)(6);
■ p. Revising paragraph (n)(2)(i);
■ q. Revising paragraphs (o) introductory text and (o)(10);
■ r. Revising paragraphs (p) introductory text and (p)(10);
■ s. Revising paragraphs (r) introductory text, (r)(2) introductory text, and (r)(2)(i);
■ t. 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 of this subpart.

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

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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, you must follow the procedures specified in paragraph (g)(1). 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. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

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

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

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 but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

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

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback for each well, p, as determined by using an appropriate meter according to methods described in § 98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of vented or flared gas for each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

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

(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) 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 of this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W–12B of this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in Equations W–12A and W–12B 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) * * *

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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 of this section converted to a flow rate for this parameter.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

* * * * *

(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. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

* * * * *

(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 Equations 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 paragraph (g)(1)(vii)(A) or (B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

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

Where:

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

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

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

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

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

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

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

* * * * *

(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.

* * * * *

(i) * * *

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. For industry segments other than onshore natural gas transmission pipeline, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary other than physical volumes associated with distribution pipelines), pipeline venting (*i.e.,* physical volumes associated with distribution pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event. For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

(i) * * *

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T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the pressure.

* * * * *

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

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last gas-liquid separator or non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator or non-separator equipment 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:

(i) Separator or non-separator equipment temperature.

(ii) Separator or non-separator equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator or non-separator equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section 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 emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

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

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

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

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

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

(A) If other non-separator equipment liquid and gas compositions are available through a previous analysis, select the latest available analysis that is representative of liquid and gas from non-separator equipment in the same county and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment liquid and gas compositions are not available, use default liquid and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

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

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

Where:

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

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed oil directly to the storage tank.

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

* * * * *

(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.

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

Where:

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

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

T_n = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_n based on maintenance, operations, or routine 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) 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) 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) 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); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11).

* * * * *

(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.

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

Where:

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

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

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

* * * * *

(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) 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) 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) 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); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11).

* * * * *

(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.

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

Where:

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

Count = Total number of reciprocating compressors.

$EF_{i,s}$ = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(r) *Equipment leaks by population count.* This paragraph (r) 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)(10), and (j)(11) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B of this section and according to paragraph (r)(6)(ii) of this section.

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

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

Where:

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a 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 by material type (protected steel, unprotected steel, plastic, or cast iron). 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 of this section.

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

(B) Multiply major equipment counts by the average component counts listed in Table W–1B of this subpart 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.

* * * * *

(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 paragraphs (z)(3) and (4) of this section, as follows:

(1) * * *

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities 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 December 31, 2016, you must use the calculation methodologies and equations in § 98.233 but you may use the best available monitoring method as described in paragraph (g)(2) of this section for any parameter specified in paragraphs (g)(3) through (6) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2016. Starting no later than January 1, 2017, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part. For onshore petroleum and natural gas production, this paragraph (g)(1) only applies if emissions from well completions and workovers of oil wells with hydraulic fracturing cause your facility to exceed the reporting threshold in § 98.231(a)(1).

(2) 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.

(3) *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.

(4) *Best available monitoring methods for measurement data 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).

(5) *Best available monitoring methods for measurement data 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.

(6) *Best available monitoring methods for specified activity data.* You may use best available monitoring methods for activity data as listed in paragraphs (g)(6)(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).

* * * * *

■ 7. Section 98.236 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraphs (a)(9) and (10);

■ c. Revising paragraphs (d)(1)(i) and (vi);

■ d. Revising paragraphs (e)(1)(i) and (xviii);

■ e. Revising paragraphs (f)(1)(ii), (f)(1)(xi)(A), (f)(1)(xii)(A), and (f)(2)(i);

■ f. Revising paragraphs (g) introductory text, (g)(1), (g)(2), (g)(5), and (g)(6);

■ g. Revising paragraphs (h)(1)(i) and (iv), (h)(2)(i) and (iv), (h)(3)(i), and (h)(4)(i);

■ h. Revising paragraphs (i) introductory text and (i)(1) introductory text;

■ i. Adding paragraph (i)(3);

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

■ k. Revising paragraphs (j)(1)(i), (iii), (iv) (v), (vii), and (viii);

■ l. Revising paragraphs (j)(2)(i) introductory text, (j)(2)(i)(A) through (C), (j)(2)(ii), (j)(2)(iii) introductory text, (j)(2)(iii)(A) and (B), and (j)(3) introductory text;

■ m. Revising paragraph (l)(1) introductory text;

■ n. Redesignating paragraphs (l)(1)(ii) through (vi) as paragraphs (l)(1)(iii) through (vii), respectively;

■ o. Adding paragraph (l)(1)(ii);

■ p. Revising newly designated paragraph (l)(1)(v);

■ q. Revising paragraph (l)(2) introductory text;

■ r. Redesignating paragraphs (l)(2)(ii) through (vii) as paragraphs (l)(2)(iii) through (viii), respectively;

■ s. Adding paragraph (l)(2)(ii);

■ t. Revising newly designated paragraph (l)(2)(v);

■ u. Revising paragraph (l)(3) introductory text;

■ v. Redesignating paragraphs (l)(3)(ii) through (v) as paragraphs (l)(3)(iii) through (vi), respectively;

■ w. Adding paragraph (l)(3)(ii);

■ x. Revising newly designated paragraph (l)(3)(iv);

■ y. Revising paragraph (l)(4) introductory text;
■ a. Redesignating paragraphs (l)(4)(ii) through (vi) as paragraphs (l)(4)(iii) through (vii), respectively;
■ aa. Adding paragraph (l)(4)(ii);
■ bb. Revising newly designated paragraph (l)(4)(iv);
■ cc. Revising paragraphs (m)(1), (m)(5), (m)(6), (m)(7)(i), (m)(8)(i);
■ dd. Revising paragraph (n)(1);
■ ee. Revising paragraphs (o) introductory text and (o)(5) introductory text;
■ ff. Revising paragraphs (p) introductory text and (p)(5) introductory text;
■ gg. Revising paragraphs (r)(1) introductory text, (r)(1)(i), (r)(3) introductory text, and (r)(3)(ii) introductory text;
■ hh. Revising paragraph (z) introductory text;
■ ii. Revising paragraphs (aa) introductory text and (aa)(1)(ii)(D) through (H);
■ jj. Adding paragraphs (aa)(10) and (11); and
■ kk. 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), 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.

* * * * *

(d) * * *

(1) * * *

(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.

* * * * *

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the unit (for the onshore petroleum and natural gas gathering and boosting industry segment only).

* * * * *

(e) * * *

(1) * * *

(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.

* * * * *

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

* * * * *

(f) * * *

(1) * * *

(ii) Well tubing diameter and pressure group ID and a list of the well ID numbers associated with each sub-basin and 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) If you used Equation W–10A of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of "$T_{p,i}$" and sum of "$T_{p,s}$" values used in Equation W–10A of § 98.233). 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 (average of ''$FR_{s,p}$'' values used in Equation W–12A of § 98.233), 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 of § 98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil (''GOR_p'' in Equation W–12C of § 98.233). 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 gas to oil ratio for the well and the well ID number for the well.

(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 of § 98.233). 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 volume of oil produced during the first 30 days of production after well completion or workover and the well ID number for the well.

(6) If you used Equation W–10B of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin (''$FV_{s,p}$'' in Equation W–10B of § 98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin (''$FR_{p,i}$'' in Equation W–10B of § 98.233).

(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 for gas well completions 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 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells 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 for gas well completions 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 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells 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 for gas well workovers without hydraulic fracturing and without flaring.

* * * * *

(4) * * *

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

(1) *Report by equipment or event type.* If you calculated emissions from blowdown vent stacks by the seven categories listed in § 98.233(i)(2) for industry segments other than the onshore natural gas transmission pipeline segment, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each ''equipment or event type'' (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the ''equipment or event type'' (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

* * * * *

(3) *Onshore natural gas transmission pipeline segment.* Report the information in paragraphs (i)(3)(i) through (iii) of this section for each state.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) Annual number of blowdown events.

(j) *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 of § 98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraphs (j)(1)(ix) and (xi) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

* * * * *

(iii) The total annual oil volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total volume of oil from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

* * * * *

(vii) 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.

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

* * * * *

(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 of § 98.233(j). 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 for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil/condensate production less than 10 barrels per day and that send oil/condensate 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/condensate throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of 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) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that did not control emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that controlled emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares.

* * * * *

(3) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (iv) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting).

* * * * *

(l) * * *

(1) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual

conditions from oil wells and the emissions are not 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 of § 98.233 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 of § 98.233 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 of § 98.233 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 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 § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(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) * * *

(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.

* * * * *

(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 (iii) of this section.

* * * * *

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting 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 (iii) of this section.

* * * * *

(r) * * *

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W–32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by 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.

* * * * *

(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.

* * * * *

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

* * * * *

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

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

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

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

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

* * * * *

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

(i) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels.

(iv) The quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels.

(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 for each state in the facility.

* * * * *

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

■ 8. Section 98.238 is amended by adding definitions for ‘‘Facility with respect to onshore 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 onshore 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. The facility does not include pipelines that are part of any other industry segment defined in this subpart.

* * * * *

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 petroleum or natural 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, or for pipelines that fall under the ''Hinshaw Exemption'' as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

* * * * *

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

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
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
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

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

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors—Gathering Pipelines, by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60
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 by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[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 factors are 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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