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Mandatory Reporting of Greenhouse Gases: Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA-HQ-OAR-2011-0512; FRL-9501-9]

RIN 2060-AR09

Mandatory Reporting of Greenhouse Gases: Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is finalizing technical corrections and revisions to the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule. Final changes include providing clarification on existing requirements, increasing flexibility for certain calculation methods, amending data reporting requirements, clarifying terms and definitions, and technical corrections.

DATES: This rule is effective on December 28, 2011.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2011-0512. All documents in the docket are listed in the <http://www.regulations.gov> index.

Although listed in the index, some information may not be 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 is publicly available in hard copy only. Publicly available docket materials are available either electronically through <http://www.regulations.gov> or in hard copy at the EPA's Docket Center, EPA/DC, EPA West Building, Room 3334, 1301 Constitution Av., NW., Washington, DC. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC-6207J), Environmental Protection

Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343-9263; fax number: (202) 343-2342; email address: GHGReportingRule@epa.gov. For technical information and implementation materials, please go to the Web site <http://www.epa.gov/climatechange/emissions/subpart/w.html>. To submit a question, select Rule Help Center, followed by "Contact Us."

Worldwide Web (WWW). In addition to being available in Docket ID No. EPA-HQ-OAR-2011-0512, following the Administrator's signature, an electronic copy of this final rule will also be available through the WWW on EPA's Greenhouse Gas Reporting Program Web site at <http://www.epa.gov/climatechange/emissions/ghrulemaking.html>.

SUPPLEMENTARY INFORMATION:

Regulated Entities. The Administrator determined that this action is subject to the provisions of Clean Air Act (CAA) section 307(d). These amended regulations could affect owners or operators of petroleum and natural gas systems. Regulated entities may include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Source category	NAICS	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211	Extractors of crude petroleum and natural gas.
	211112	Natural gas liquid extraction facilities.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Other types of facilities not listed in the table could also be affected. 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? This final rule is effective on December 28, 2011. Section 553(d) of the Administrative Procedure Act (APA), 5 U.S.C. Chapter 5, generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**. EPA is issuing this final rule under section CAA 307(d)(1), which states:

“The provisions of section 553 through 557 * * * of Title 5 shall not, except as expressly provided in this section, apply to actions to which this subsection applies.” Thus, section 553(d) of the APA does not apply to this rule. EPA is nevertheless acting consistently with the purposes underlying APA section 553(d) in making this rule effective on December 28, 2011. Section 5 U.S.C. 553(d)(3) allows an effective date less than 30 days after publication “as otherwise provided by the agency for good cause found and published with the rule.” As explained below, EPA finds that there is good cause for parts of this rule to become effective on December 28, 2011 even though this will result in an effective date fewer than 30 days from the date of publication in the **Federal Register**.

The purpose of the 30-day waiting period prescribed in 5 U.S.C. 553(d) is to give affected parties a reasonable time

to adjust their behavior and prepare before the final rule takes effect. That purpose, to provide affected parties a reasonable time to prepare for the rule before it comes into effect, is not necessary in this case, as most of the affected provisions in the final rule clarify existing provisions, provide flexibilities to sources covered by the reporting rule, or otherwise relieve a restriction. For example, this final rule clarifies the definition of some of the industry segments, and in some cases, provides further flexibility relating to reporting obligations that would otherwise have been required by the November 2010 Subpart W (the 2010 final rule) 75 FR 74458. Therefore, EPA finds good cause exists to make this rule effective on December 28, 2011.

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 February 21, 2012. 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 EPA to convene a proceeding for reconsideration, “[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.” Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios 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, 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 EPA to enforce these requirements.

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

AGA American Gas Association
 AGR Acid Gas Removal
 API American Petroleum Institute
 AXPC American Exploration and Production Council
 BMM Best Available Monitoring Methods
 BOEMRE Bureau of Ocean Energy Management, Regulation and Enforcement
 CAA Clean Air Act
 CBI confidential business information
 CEC Chesapeake Energy Corporation
 CEMS continuous emission monitoring systems
 cfd cubic feet per day
 CFR Code of Federal Regulations
 CH₄ methane
 CO₂ carbon dioxide
 CO₂e CO₂-equivalent
 COR certificate of representation
 e-GGRT electronic greenhouse gas reporting tool
 EIA Economic Impact Analysis
 EOR enhanced oil recovery
 EPA U.S. Environmental Protection Agency
 FCML Field Code Master List
 FERF Federal Energy Regulatory Commission
 FR Federal Register

GHG greenhouse gas
 GPA Gas Processors Association
 GOR gas to oil ratio
 GRI Gas Research Institute
 Hp horsepower
 GWP global warming potential
 HHV high heat value
 IBR incorporation by reference
 ICR information collection request
 LDC Local Distribution Company
 ISO International Organization for Standardization
 kg kilograms
 LDCs local natural gas distribution companies
 LNG liquefied natural gas
 M&R meters and regulators
 mmBtu million British thermal units
 mmHg millimeters of Mercury
 MMscfd million standard cubic feet per day
 mTCO₂e million metric tons carbon dioxide equivalent
 MRR mandatory GHG reporting rule
 N₂O nitrous oxide
 NAICS North American Industry Classification System
 NGLs natural gas liquids
 NPS nominal pipe size
 NTTAA National Technology Transfer and Advancement Act
 OAQPS Office of Air Quality, Planning and Standards
 OMB Office of Management and Budget
 PHMSA Pipeline and Hazardous Material Safety Administration
 QA/QC quality assurance/quality control
 RFA Regulatory Flexibility Act
 SBA Small Business Administration
 SBREFA Small Business Regulatory Enforcement and Fairness Act
 T-D Transmission Distribution
 TSD technical support document
 U.S. United States
 UMRA Unfunded Mandates Reform Act of 1995
 USC United States Code

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I. Background

A. Organization of This Preamble

This preamble consists of three sections. The first section provides a brief history of 40 CFR part 98 and 40 CFR part 98, subpart W (“subpart W”).

The second section of this preamble summarizes the revisions made to specific requirements for subparts A and W being incorporated by this action. The amendments finalized in this action reflect the changes to subpart W proposed in two separate proposed rules (76 FR 56010, 76 FR 47392). This section also describes the major changes made to this source category since proposal and provides a brief summary of significant public comments and EPA’s responses. Additional responses to significant comments can be located in the document, “Mandatory Reporting of Greenhouse Gases—Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments” see EPA-HQ-OAR-2011-0512.

Finally, the last section discusses the various statutory and executive order requirements applicable to this rulemaking.

B. Background

This action finalizes amendments to provisions in 40 CFR part 98, subpart A. The 2009 final GHG reporting rule was signed by the EPA Administrator Lisa Jackson on September 22, 2009 and published in the **Federal Register** on October 30, 2009 (74 FR 56260, October 30, 2009 hereinafter “GHGRP”). The 2009 final rule, which became effective on December 29, 2009, includes reporting of GHGs from various facilities and suppliers consistent with the 2008 Consolidated Appropriation Act (Consolidated Appropriations Act, 2008, Public Law 110-161, 121 Stat. 1844,

2128). Subsequent notices were published in 2010 finalizing the requirements for subpart W (74 FR 74458).

In an earlier action, EPA proposed minor technical corrections to specific provisions in various subparts of the greenhouse gas reporting rule, including subpart W on August 4, 2011 (76 FR 47392), hereinafter “GHGRP Corrections Proposal”). In that action, EPA proposed several corrections to specific provisions in subpart W to address minor errors in equations and to correct certain erroneous citations.

In this action, EPA is finalizing amendments to provisions in subpart W that were proposed in both the September 9, 2011 GHGRP Revisions Proposal action and the August 4, 2011 GHGRP Corrections Proposal action. Responses to comments submitted on both actions can be found in section II.C of this preamble and also under the document “Mandatory Reporting of Greenhouse Gases—Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments” See EPA–HQ–OAR–2011–0512.

C. Legal Authority

The EPA is promulgating these rule amendments under its existing CAA authority, specifically authorities provided in CAA section 114.

As stated in the preamble to the 2009 final rule (74 FR 56260, October 30, 2009), CAA section 114 provides EPA broad authority to require the information mandated by 40 CFR part 98 because such data would inform and are relevant to the EPA’s obligation to carry out a wide variety of CAA provisions. As discussed in the preamble to the initial proposal (74 FR 16448, April 10, 2009), CAA section 114(a)(1) authorizes the Administrator to require emissions sources, persons subject to the CAA, manufacturers of process or control equipment, and persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests for the purposes of carrying out any provision of the CAA. For further information about the EPA’s legal authority, see the preambles to the proposed and final rule, and related Response to Comments documents.

D. How Confidential Business Information Determinations and the Deferral of Inputs to Emission Equations Are Affected by This Action

The EPA finalized several rulemakings during 2011 in response to concerns related to the reporting and publication of information that may be considered confidential business information (CBI). For more information on the final action to defer the reporting deadline for data elements that are used by direct emitter reporters as inputs to emissions equations under EPA’s Greenhouse Gas Reporting Program, please see the Final CBI Deferral Rule (75 FR 53057, August 25, 2011, hereinafter referred to the “Final CBI Deferral Rule”). For more information generally on the various actions related to treatment of data that may be considered CBI, please see the GHG Reporting Program Web site dedicated to CBI at <http://www.epa.gov/climatechange/emissions/CBI.html>.

On May 26, 2011, the EPA published confidentiality determinations for certain data elements required to be reported under 40 CFR part 98 and finalized amendments to the Special Rules Governing Certain Information Obtained Under the Clean Air Act, which authorizes the EPA to release or withhold as confidential reported data according to the confidentiality determinations for such data without taking further procedural steps (76 FR 30782, 2011 hereinafter referred to as the “Final CBI Rule”). The Final CBI Rule addressed reporting of data elements in 34 subparts which were determined not to be inputs to emission equations and therefore are always CBI and which are not eligible to be CBI. That rule did not make confidentiality determinations for eight subparts, including subpart W, for which reporting requirements were finalized after publication of the July 7, 2010 CBI proposal (75 FR 39094) and December 27, 2010 supplemental CBI proposal (75 FR 43889).

On August 25, 2011, the EPA published a final rule that deferred the reporting deadline for data elements that are used by direct emitter reporters as inputs to emission equations under the Mandatory Greenhouse Gas Reporting Rule (76 FR 53057, Final CBI Deferral Rule). The Final CBI Deferral Rule, included deferral of the deadline for reporting inputs to emissions equations based on the 2010 final rule for 40 CFR part 98, subpart W (75 FR 74458).

EPA intends to propose and finalize CBI determinations for 40 CFR part 98, subpart W in a separate action (or

actions). This final rule does not affect the deferral of reporting nor the date until which the deadline is set for reporting those inputs to emissions equations for subpart W, which were finalized in the Final CBI Deferral Rule. For subpart W, EPA intends to finalize a deferral of any new or revised inputs affected by this final action prior to the 2012 reporting deadline.

E. How do these amendments apply to 2012 reports?

We have determined that it is feasible for owners and operators covered by this rule to implement these technical amendments for the 2011 reporting year because the revisions primarily provide additional clarification regarding applicability, and the existing regulatory requirements generally do not change the type of information that must be collected, and do not materially affect how GHG emissions or quantities are calculated. Our rationale for this determination is explained in the preamble to the proposed rule amendments.¹

In response to comments submitted on the proposed rulemaking, we have reviewed the final amendments and determined that they can be implemented, as finalized, for the 2011 reporting year. Although in limited cases these amendments may introduce revisions to calculation procedures from those proposed (e.g., for taking measurements at the sub-basin level as opposed to the field level), in response to comment, EPA has introduced flexibilities in the final rule in order to ensure that there are no new monitoring requirements for 2011.

As an example of the flexibility introduced in this final rule, in the GHGRP Revisions Proposal, EPA proposed an alternative approach to taking measurement at the field level, as suggested by industry, by proposing to take measurement at a sub-basin level. Industry requested that EPA reconsider the use of a field-level measurement plan for specific emissions sources including well venting for liquids unloading and well venting for well completions/workovers, by stating that it was not clear how to assign a field name to new wells, nor how to address wells that were not contained in the 2008 EIA Field Code Master List which was incorporated by reference in the Subpart W Final Rule. The foundation of the sub-basin approach is defining a sub-basin category through the use of a county level designation and the distinction of the type of hydrocarbon formation. The hydrocarbon formations

¹ 76 FR 56010 (September 9, 2011).

can be grouped into five types: Oil, high permeability gas, shale gas, coal seam, or other tight reservoir rock. For example, wells producing coal bed methane from formation "X" with wellhead coordinates within county "A" would be one sub-basin category. Further, wells producing from tight formation "Y" with wellhead coordinates within county "A" would be a second sub-basin category. In the event that a specific county includes more than one formation (e.g., coal bed methane and tight sands), then the reporter would use the most specific designation (e.g., coal bed methane). EPA analyzed the approach suggested by the industry and believes that the sub-basin category provides similar quality data as the EIA field code would provide, while still achieving the appropriate level of data representativeness. Please see Economic Impact Analysis Memorandum in Docket ID EPA-HQ-OAR-2011-0512.

Therefore, as industry suggested, EPA proposed the alternative approach of using a sub-basin measurement level for measurement of specific emission sources in the onshore production industry segment, and is finalizing that approach in this action. For example, commenters were generally supportive of EPA's proposed change to require calculation and reporting for onshore production at the sub-basin level, as opposed to the field level. However, one commenter requested to continue to use field as a classification mechanism for groups of wells within each basin. The commenter stated that they had already conducted field-level calculations for 2011. In response to this concern, and for the 2011 reporting year only, EPA is allowing reporters who took measurement at the field level to apply those measurements to the equivalent sub-basins applicable to their facility as a best available monitoring method (BAMM). The use of a field-level measurement as a BAMM for a sub-basin measurement fits within a recently finalized action (76 FR 59533), where EPA granted subpart W reporters the option to use BAMM for all of 2011 without reporters being required to submit a request for approval from the Administrator. For data collection in 2012 and beyond, reporters must use the sub-basin level for data collection.

By way of further example, the 2010 final rule required facilities to assume that pneumatic pumps and pneumatic devices were operational the entire year. We proposed that instead of assuming operation for 8,760 hours per year, facilities would use their actual operating hours. While many reporters agreed with the proposed amendment,

they encouraged EPA to retain the option of assuming 100 percent operation during the reporting year, so as not to require facilities to track operating hours. In this action, reporters now have the option to use actual operating hours or the default of 8,760 hours per year for both pneumatic devices and pneumatic pumps when calculating GHG emissions using equation W-1 and W-2 in 40 CFR 98.233(a) and (b) respectively. Thus in any given data collection year, reporters now have the option of using the default or entering their estimated amount of hours for operation of their pneumatic devices and pumps. This option will not be limited to the 2011 data collection year.

Lastly, the 2010 final rule requires reporters to take measurement once in a two year cycle, beginning with the first year of data collection, for emission sources including the gas well venting from completions or workovers with hydraulic fracturing emission source type. In this action, EPA is revising several provisions related to these emission sources and because the revisions are expected to be published late in the 2011 data collection year, EPA is allowing reporters additional flexibility by giving the option to take their first measurement in the second year as opposed to the first year, as is stated in the rule, 40 CFR 98.234(g). Reporters who chose this option must take their measurement before the September 28, 2011 reporting deadline for subpart W.

II. Overview of Final Amendments to the General Provisions, and Petroleum and Natural Gas Systems Source Category and Responses to Major Public Comments

A. Amendments to the General Provisions

Purpose and Scope. In this action, EPA is amending 40 CFR 98.1 of the general provisions by adding paragraph (c) which states that for the purposes of applying the terms owner and operator used in subpart A, facilities required to report under the onshore petroleum and natural gas production industry segment of 40 CFR part 98, subpart W will use the definition of onshore petroleum and natural gas production owner or operator in 40 CFR 98.238.

Definitions. EPA is finalizing amendments to definitions in 40 CFR 98.6. First, we are amending the text for the definition for continuous bleed pneumatic devices, in 40 CFR 98.6 to clarify that continuous bleed devices supply natural gas to process control

devices, and not measurement devices, as suggested by the 2010 final rule.

Secondly, we are amending the definition of intermittent bleed pneumatic devices, as proposed, to clarify that these devices automatically maintain the process conditions and that the devices are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary.

There were no other major changes to 40 CFR subpart A since the proposal.

B. Responses to Major Comments Submitted on the General Provisions

1. Further Delineation of Types of Intermittent Bleed Pneumatic Devices

Comment: Commenters were generally supportive of EPA's proposal to clarify the definitions for pneumatic devices in the September 9, 2011 GHGRP Revisions Proposal. One commenter, however, specifically noted that further clarification to the definition for intermittent devices was necessary beyond the proposal and requested that EPA list out examples of intermittent bleed devices.

Response: EPA believes that the definition for intermittent bleed pneumatic devices finalized in this action is sufficient for reporters to use as a guideline in determining what would constitute an intermittent bleed pneumatic device. The definition for intermittent pneumatic devices finalized in this action clarifies that these types of pneumatic devices automatically maintain the process conditions and discharge all or a portion of the full volume of the actuator intermittently.

C. Final Amendments to the Petroleum and Natural Gas Systems Source Category

In this action, EPA is amending several provisions to the Final Subpart W Rule published in November 2010. The major amendments are listed in this section, followed by a more detailed summary of the final amendments to the various provisions. Where appropriate, it is indicated that an amendment was finalized as proposed, or an amendment as finalized that differed from the GHGRP Corrections proposal or the GHGRP Revisions proposal. Other changes and clarifications included in this section are administrative in nature. For a full description of the rationale for these and any other significant change to 40 CFR part 98, subpart W, see the "Mandatory Reporting of Greenhouse Gases—Technical Revisions to the Petroleum and Natural Gas Systems

Category of the Greenhouse Gas Reporting Rule: EPA's Response to Public Comments" and section II.D Responses to Major Comments Submitted on the Petroleum and Natural Gas Systems Source Category.

Major Changes Since Proposal

1. Calculating GHG Emissions

- Inclusion of clarification for emergency blowdown vent stack emission sources that are covered under 40 CFR 98.233(i).

- Revising calculation methodologies for natural gas distribution industry segment in 40 CFR 98.233(q) and 40 CFR 98.233(r) to allow for reporters to use a 5-year rolling survey plan.

- Revising the emission factor for intermittent pneumatic devices.

2. Data Reporting Requirements

- Not adopting the proposed amendments to include reporting of a unique name or ID for specified emissions sources under the onshore petroleum and natural gas production industry segment throughout 40 CFR 98.236.

- Replacing the term "a unique name or ID number for the blowdown vent stack" in 40 CFR 98.236(c)(7)(iii) to "a unique name or ID number for the unique volume type."

- Inclusion of data reporting requirements for natural gas distribution industry segment to reflect the 5-year rolling survey plan.

3. Definitions

- Revising definition for associated with a well-pad in 40 CFR 98.238 by revising the last sentence.

- Inclusion of a definition for a 5th sub-basin category for oil in the 40 CFR 98.238 sub-basin definitions.

4. Emission Factor Tables

- Revising emission factors in tables W-1A, W-2, W-3, W-4, W-5, W-6, and W-7 to adjust for 60° standard temperature and 14.7 psia pressure.

The final amendments are organized following the different sections of the subpart W regulatory text beginning with 40 CFR 98.230 and going through 98.238. As described above in Section II.E., one of the major changes is for the onshore petroleum and natural gas production industry segment, where the reporting level has been changed from the field level to the sub-basin level.

Source Category Definitions. In general, we are finalizing amendments to the source category definitions as proposed to clarify both the coverage of individual industry segments and the boundaries for different industry segments. The purpose of these

amendments is primarily to clarify the coverage of the rule and ensure applicability under 40 CFR part 98 is as originally intended.

Onshore Petroleum and Natural Gas Production. We are making several amendments to the definition for the onshore petroleum and natural gas production (also referred to as onshore production) industry segment in 40 CFR 98.230(a)(2). First, EPA is revising the term "associated with a well-pad" to state that the onshore production industry segment includes equipment that is "on a single well-pad or associated with a single well-pad." These equipment are included in the onshore production industry segment irrespective of the point of emissions from that equipment (e.g., if emissions from one or more pieces of onshore oil and gas production equipment are sent to a common header either to a flare or vent, that vent or flare would also be included). Next, EPA is amending the definition to clarify that both dehydrators and storage vessels that are on a single well-pad or associated with a single well-pad are included as types of equipment that are considered part of the onshore production industry segment if they are owned or operated by the onshore production owner or operator, including equipment that is leased, contracted or rented.

Finally, we are revising the text to state that enhanced oil recovery (EOR) operations that use either CO₂ or natural gas are a part of this industry segment.

Onshore Natural Gas Processing. EPA is including several clarifications to the onshore natural gas processing industry segment definition in 40 CFR 98.230(a)(3). First, we are striking the term "and recovers" from the first sentence, in order to more clearly characterize the unique activities performed at natural gas processing plants. Second, we are revising the text to clarify that this industry segment includes one or a combination of the following three processes: separation of natural gas liquids (NGLs) from produced natural gas, separation of non-methane gases from produced natural gas, or separation of NGLs into one or more component mixtures. Third, we are amending the definition to clarify that separation means one or more of the following processes: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO₂ separated from natural gas streams. Fourth, we are striking the phrase "this industry segment does not include reporting of emissions from gathering lines and boosting stations" because the final amendments already clarify the

definition of "onshore natural gas processing" and therefore, it is unnecessary to discuss that which is excluded. Fifth, we are revising the threshold contained in the definition of the onshore natural gas processing segment to be 25 million standard cubic feet annual average daily throughput. Finally, we are replacing out the term "facility" with the term "plant".

Onshore Natural Gas Transmission Compression. EPA is finalizing several clarifications to the onshore natural gas transmission compression industry segment definition in 40 CFR 98.230(a)(4). First, we are removing the term "at elevated pressure" to address confusion associated with what "elevated pressure" actually meant. Next, we are including a definition in 40 CFR 98.238 of transmission pipeline to address concerns that this term was undefined and could have a broader meaning than that which was intended in the 2010 final rule. We are defining a transmission pipeline to mean 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).

Next, we are clarifying the definition for the transmission compression industry segment. The final rule provides that natural gas transmission compression facilities not only move natural gas from production fields or gas processing plants, but also move natural gas coming from other transmission compressors. In addition, we are explicitly stating that natural gas transmission compression facilities not only move natural gas into distribution pipelines, but also into liquefied natural gas storage or into underground storage.

We are removing the term "natural gas dehydration" from the industry segment definition because this term did not represent a unique characteristic of facilities with natural gas transmission compression. Finally, we are removing the reference to "gathering lines and boosting stations" and "facility" for the same reasons as explained above relating to the onshore processing industry segment definition.

Natural Gas Distribution. EPA is amending the natural gas distribution industry segment definition to further clarify applicability under the rule. First, we are replacing the term "city gate station" with the term "metering-regulating station" in 40 CFR 98.230(a)(8). This amendment is designed to more clearly express EPA's intent using language readily understood by industry. As a

harmonizing change, we are also adding a definition for the term “metering-regulating station” in 40 CFR 98.238 to state that, “[a]n above ground station that meters the flow rate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps”. With this amendment, we are clarifying key concepts in the definition, without actually changing coverage by the rule.

We are removing the parenthetical term “(not interstate transmission pipelines or intrastate transmission pipelines)” as this statement was not necessary. Instead we are adding a definition for “distribution pipeline” in 40 CFR 98.238 that clarifies that “distribution pipelines” are only those designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3.

Next, we are removing the term “excluding customer meters” and “physically deliver natural gas to end users” because the definition for “meter-regulator” stations described above already addresses this exclusion.

Finally, we are amending the industry segment definition to explicitly state that the LDC reporting as a single facility is that which is operated in a single state and regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This change ensures that the definition of LDC is consistent between subpart W and subpart NN.

Greenhouse Gases to Report. We are amending several provisions for the greenhouse gases that must be reported in 40 CFR 98.232.

We are amending 40 CFR 98.232(c) to clarify that the source listed in 40 CFR 98.232(c)(1) through (22) are on a single well-pad or associated with a single well-pad. This change is consistent with the final changes to the onshore production industry segment definition in 40 CFR 98.230(a)(2) described above. In 40 CFR 98.232 (c)(22), EPA is replacing the term “production well pad” with “petroleum and natural gas production facility as defined in 98.238”. This change makes the term consistent with language used throughout Subpart W.

Next, we are amending 40 CFR 98.232(i) by replacing the term “custody transfer city gate station” with the term “transmission-distribution transfer station” and replacing the term “non-custody transfer station” with the term “metering-regulating station.” We are amending the source types for this industry segment by removing the text

“Customer meters are excluded.” This text was removed because it was no longer necessary with the addition of the term “transmission-distribution transfer station” and its definition. Further we are amending 40 CFR 98.232(i) to state that CO₂, CH₄ and N₂O emissions are to be reported from the natural gas distribution industry segment. This clarification is consistent with the calculation procedures in 40 CFR 98.233. Finally, EPA added emissions sources that were already required to be reported under 40 CFR part 98, subpart W but were not listed under 40 CFR 98.232 (i) (*i.e.*, pipeline main equipment leaks, service line equipment leaks, and stationary combustion).

Next, we are removing and reserving 40 CFR 98.232(j), as proposed, in order to address concerns raised that the inclusion of this provision resulted in confusion amongst reporters as they were unsure how this provision aligned with the flare emissions that are captured under the applicable emissions source calculations throughout 40 CFR 98.233. Accordingly, we are also finalizing, as proposed, the introductory sentences to 40 CFR 98.232(d), (e), (f), (g), (h), and (i) to clarify that N₂O emissions are also required to be reported under these industry segments. We are making a harmonizing change to 40 CFR 98.232(a), to remove the reference to 40 CFR 98.232 (j).

Lastly, we are amending 40 CFR 98.232(k) to clarify that the onshore petroleum and natural gas production and natural gas distribution industry segments are to report their combustion emissions under 40 CFR part 98, subpart W, while the remaining industry segments are to report their combustion emissions under subpart C of part 98.

Calculating Greenhouse Gas Emissions. We are making several clarifications, corrections, and amendments throughout 40 CFR 98.233.

Natural Gas Pneumatic Device Venting

EPA is modifying Equation W-1 by adding the subscript “t” to the equation to represent the different device types. EPA is removing the subscript “s,” and the word “standard” from the definition of parameter Mass_{s,i} because mass emissions do not need to be reported at standard conditions. EPA is amending Equation W-1, to include a parameter “T” that estimates the total number of hours in a year the devices were operational instead of assuming that the natural gas pneumatic devices was operating the whole year. However, EPA has provided a value of 8,760 hours for reporters to use as a default option. Further, EPA is clarifying that

compositions in 40 CFR 98.233(u)(2)(i) may be used for the onshore petroleum and natural gas production in the definition for “GHG_i”. However, for onshore natural gas transmission compression, and underground natural gas storage industry segments, set values of 0.975 for CH₄ and 1.1×10^{-2} for CO₂ are used. The value of 0.975 represents the methane fraction of total hydrocarbon (THC) which is the basis of the emission factors in Tables W-3 for Natural Gas Transmission Compression and Table W-4 for Underground Natural Gas Storage where the non-hydrocarbon fraction of pipeline quality gas (made up of primarily carbon dioxide and nitrogen) is approximately 2%. The carbon dioxide fraction of total hydrocarbons in Tables W-3 and W-4 is determined from public records on pipeline gas quality. The value of 1.1×10^{-2} represents the ratio of CO₂ to methane in transmission gas. Under the parameter definition of Conv_i, EPA amended the value of emission factors to 0.000403 for CH₄ and 0.00005262 for CO₂ to account for an error in the previous factor not being adjusted to standard conditions. EPA is revising 40 CFR 98.233(a) by adding 40 CFR 98.233(a)(3), which allows reporters to determine the type of pneumatic devices using engineering estimation based on best available information. This amendment is in response to questions about how to determine whether a pneumatic device is continuous high bleed, continuous low bleed, or intermittent bleed and the burden associated with determining the type of pneumatic device.

Lastly, the data reporting requirements in 40 CFR 98.236(c)(1)(iv), which are associated with pneumatic devices, have been clarified to require aggregate emissions to be reported for all continuous high bleed pneumatic devices, for all intermittent bleed pneumatic devices, and for all continuous low bleed pneumatic devices separately at the facility level.

Natural Gas Driven Pneumatic Pump Venting

We are amending Equation W-2 in 40 CFR 98.233(c), to include a parameter “T” that estimates the total number of hours in a year the pumps were operational instead of assuming that the pneumatic pump was operating the whole year. EPA has provided a value of 8,760 hours for reporters to use as a default option. EPA is removing the subscript “s,” since mass emissions do not need to be reported at standard conditions.

Acid Gas Removal (AGR) Vents. EPA is amending 40 CFR 98.233(d) to clarify EPA's intent and to correct errors.

We are revising provisions in 40 CFR 98.233(d) to clarify how the four different methods are to be used for determining GHG emissions from acid gas removal units. First, we are amending 40 CFR 98.233(d)(1) to specify that the use of CEMS is required if a CO₂ concentration monitor and volumetric flow rate monitor are installed. This amendment was made to clarify what conditions must be met to satisfy Tier 4 calculation requirement in Subpart C for Acid Gas Removal vents. EPA is allowing reporters the flexibility to follow the calculation, quality assurance, reporting, and recordkeeping requirements in Tier 4 in Subpart C, manufacturer instructions, or industry standard practice for CEMS units already in place.

EPA is revising 40 CFR 98.233(d)(2), (d)(3), and (d)(4) to clarify that if a facility has a vent meter but no CEMS available, then they would use Calculation Methodology 2. If a facility has neither a CEMS available nor a vent meter in place (with the added flexibility to use industry consensus standards to calibrate the vent meters), then either Calculation Methodology 3 or 4 of 40 CFR 98.233(d) may be used.

Next, we are revising the equation used for estimating CO₂ emissions from acid gas removal vents in Equation W-4A and Equation W-4B in Calculation Methodology 3 in 40 CFR 98.233(d). This new equation addresses issues that arose with the previous equation, because that equation was better suited to situations where the change in CO₂ volume fraction between the inlet gas and the outlet gas would be relatively low, such as 1 percent. These two new equations will increase the accuracy of the calculation while adding no additional burden to reporters because the same parameters are monitored. Further details on the revised equations have been provided in the memo "Acid Gas Removal Vents—Engineering Calculation Revisions" located in the docket: EPA-HQ-OAR-2011-0512.

EPA is amending several associated data reporting requirements in 40 CFR 98.236(c)(3). First, we are clarifying that the annual average CO₂ content should be reported for volume fraction measurements undertaken in 40 CFR 98.233(d). Second, we are clarifying that reporters must report the annual quantity of CO₂ recovered from the AGR unit and the CO₂ emissions from the AGR unit separately. Third, we are finalizing the reporting of a unique ID for each AGR unit in industry segments other than onshore petroleum and

natural gas production, as proposed (see Section II.D. of the preamble for further details on this issue). Lastly, we are asking reporters to indicate which methodology they are using to calculate emissions from AGRs.

Dehydrator Vents. EPA is amending several of the provisions in 40 CFR 98.233(e) for calculating GHGs from dehydrator vents.

First, we are clarifying that the equipment threshold referenced throughout this section for glycol dehydrators is based on annual average daily throughput at standard conditions. This amendment was necessary to address ambiguity in the final rule provisions regarding determination of the average throughput.

Next, we are clarifying that gases other than natural gas, such as nitrogen, flash gas from the flash tanks, or dry gas from the absorber, that are used as stripping gases satisfy the requirements stated in 40 CFR 98.233(e)(1)(vii). EPA is also correcting the citation in 40 CFR 98.233(e)(1)(xi), (e)(1)(xi)(A) through (e)(1)(xi)(C).

Further, EPA clarified parameters in Equation W-5. EPA has finalized the use of 60 degree Fahrenheit and 14.7 psia as standard conditions for all of subpart W; therefore, parameter EF_i was revised to reflect the standard conditions. In addition, EPA clarified that the parameter 1,000 converts emissions from thousand standard cubic feet to standard cubic feet instead of cubic feet.

Next, we are also amending 40 CFR 98.233(e)(6) to clarify that GHG mass emissions from glycol dehydrators are to be calculated from volumetric GHG emissions using calculations in 40 CFR 98.233(v) where as GHG volumetric and mass emissions from desiccant dehydrators should be calculated using paragraphs 40 CFR 98.233(u) and 98.233(v).

Accordingly, we are clarifying in 40 CFR 98.236(c)(4) the requirement to report vented and flared emissions separately. We are also clarifying the data reporting requirements by specifying that should any vent gas controls be used on glycol dehydrators with a throughput less than 0.4 million standard cubic feet, that reporters must indicate that in their annual reports. Additionally, we are finalizing the reporting of a unique ID, as proposed, for each glycol dehydrator in industry segments other than onshore petroleum and natural gas production (see Section II.D. of the preamble for further details on this issue). Finally, we are clarifying that emissions from desiccant dehydrators must be reported at the facility level.

Well Venting for Liquids Unloadings. First, we are revising 40 CFR 98.233(f) Calculation Methodology 1 by finalizing several amendments that were proposed, including that sampling is to be done at a sub-basin level as opposed to a field-level. Further, we are finalizing the provision stating that the average flow rate must be determined for one well in a tubing diameter group and pressure group in each sub-basin category. As proposed in the GHGRP Revisions Proposal, EPA has also added a definition for the term "pressure groups" in 40 CFR 98.238 to inform reporters of the ranges for the pressure groupings that are applicable to the sub-basins, and the types of pressures that may be used for those groupings. The pressure ranges, as proposed and finalized, were optimized using HPDI well counts in 5 psig pressure increments from zero gauge pressure to 200 psig. The fifth "unbounded" pressure range is "greater than 200 psig," which EPA believes will have very few well liquids unloading venting to the atmosphere. The three tubing diameter ranges, equal or less than 1 inch, greater than 1 inch and equal or less than 2 inch, and greater than 2 inch, were derived from gas well tubing suppliers' specifications, as proposed. The relevancy of these pressure ranges and tubing diameter ranges is that liquids unloading venting is dependent on both the shut-in pressure of the reservoir (shut-in by liquids accumulation) and velocity of gas pushing liquids up the tubing, which is a function of tubing diameter. For further background on the selection of these pressure groupings and for the analysis done see "2011 Technical Revisions to the Petroleum and Natural Gas Systems Category of the GHG Reporting Rule: Summary of questions raised on Subpart W" docket number EPA-HQ-OAR-2011-0512-0015 and "Sub-Basin Entity Pressure Range Analysis" docket number EPA-HQ-OAR-2011-0016.

EPA also clarified in 40 CFR 98.233(f)(1)(i)(B) that the determined flow rate can be used for all other wells in that tubing diameter group and pressure group in a sub-basin category. Finally EPA clarified in 40 CFR 98.233(f)(1)(i)(C) that a new producing sub-basin category must determine an average flow rate during the beginning of the first year of production.

In this action, we are also including corrections to Equation W-7, as proposed. EPA is modifying Equation W-7 to address the ambiguity regarding tubing diameter group and pressure group combinations in a sub-basin. Furthermore the subscripts "t" and "q"

were removed along with a summation sign to clarify that emissions are calculated for all wells in a tubing diameter group and pressure group in a sub-basin. Accordingly, subscripts “h” and “p” represent wells of the same tubing diameter group and pressure group.

EPA is revising Equation W-8 and W-9 by correcting the definition for parameter $E_{a,n}$ to be $E_{s,n}$ to accurately reflect that the calculated emissions should be in standard conditions and not actual conditions. The parameter definition was also modified to state that the emissions are at standard conditions. These revisions from actual conditions to standard conditions were necessary to maintain uniformity in the approach to calculating GHG emissions across 40 CFR subpart W. EPA is including revisions to the parameters in Equation W-8 and W-9 to account for each unloading instance, q , and for each well, p , in a pressure grouping and sub-basin category. In addition, the parameter W was added to define the limits of the summation. These amendments address ambiguity with the summation operation in the 2010 final rule for this equation.

Next, we are amending the definition for “SFR_p” to state that the average sales flow rate of gas is to be obtained at standard conditions. We are also clarifying that Equation W-33 is to be used to convert the sales flow rate from actual to standard conditions. In addition, the definition for parameter WD_p has been clarified to mean the distance between the either the top of the well or the lowest packer to the bottom of the well. Furthermore, CD_p in Equation W-8 and TD_p in Equation W-9 represent the internal diameter of the casing and tubing, respectively. Finally, the reference to 40 CFR 98.233 (t) in 40 CFR 98.233 (f)(2) and 98.233 (f)(30) has been removed to avoid double correction for standard conditions.

For parameter SP_p in Equation W-8, EPA is allowing the use of shut-in pressure, surface pressure, or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well in the same sub-basin. For parameter SP_p in Equation W-9, EPA is allowing the use of an engineering estimate based on best available data to determine the sales line pressure. EPA is adding options and flexibility because of comments suggesting that the shut-in pressure is not known for all wells. Finally, the units for SP_p in Equation W-8 and W-9 have been corrected from pounds per square inch absolute instead of pounds per square inch atmosphere.

Accordingly, in the data reporting requirements in 40 CFR 98.236(c)(5), we are making a harmonizing change, consistent with the amendments described above. Separate reporting requirements have been included for Calculation Methodology 2 and 3 because emissions are not reported by well tubing diameter grouping and pressure grouping within each sub-basin category as in Calculation Methodology 1. All added requirements are data elements used in the engineering calculation in Equation W-8 and W-9.

Gas Well Venting During Completions and Workovers from Hydraulic Fracturing. EPA is amending 40 CFR 98.233(g) to account for the changes in aggregation from field level to sub-basin category for taking measurements, as proposed. First, we are replacing the term “field” with “sub-basin and well type (horizontal vs. vertical) combination” in the parameter definitions and clarifying that the GHG emissions are determined for each sub-basin and well type combination.

Next, we are amending Equation W-10A and adding Equation W-10B. Reporters can use Equation W-10A if the backflow from all the wells in a sub-basin and well-type combination are not being metered, where as reporters can use Equation W-10B if the backflow volumes from all wells in a sub-basin and well-type combination are being metered.

In Equation W-10A, the time period parameter T_p is redefined to be the time of backflow for the completion or workover. Equation W-10A has a new parameter, FRM, which represents the ratio of backflow during completions and workovers to 30-day production rate. FRM is calculated in Equation W-12 by dividing the metered flowback volume from the measured well(s) by the 30 day production rate. This ratio allows reporters to determine a backflow rate for wells that are not measured using the first 30 days production flow rate (PR_p), which is readily available to reporters. EPA also added a reference to 40 CFR 98.233 (g)(3) in the parameter definition of SG_p .

EPA is adding Equation W-10B to allow reporters to determine emissions if the backflow volumes are measured for all wells in a sub-basin and well-type combination. Reporters must measure the complete backflow volume during the completion or workover. This is represented by the parameter FV_p in Equation W-10B.

In Equation W-10A and Equation W-10B, EPA is adding the parameter W , which is the number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type

combination, and, where appropriate, made the parameters applicable to each well p . These amendments correct the summation operator to make it mathematically accurate.

In Equation W-11C, EPA is finalizing amendments to allow reporters to use best engineering estimate based on best available data to determine whether the well flow of gas during backflow (*i.e.* FR_p) is sonic or sub-sonic flow. EPA also clarified in 40 CFR 98.233(g)(1)(ii) that reporters can determine whether to use Equation W-11A, which is for sub-sonic flow, or Equation W-11B, which is for sonic flow.

EPA is clarifying that paragraphs 40 CFR 98.233 (g)(1)(iv) and 40 CFR 98.233 (g)(1)(v) are applicable to Equation W-10A only. EPA is replacing 40 CFR 98.233(g)(3) with 40 CFR 98.233(g)(5). Previously, the requirements stated in these paragraphs were duplicative.

Lastly, we are finalizing several harmonizing changes to the data reporting requirements for this emissions source in 40 CFR 98.236 (c)(6)(i). We are indicating in the data reporting requirements that reporting is required for each sub-basin category and well type (horizontal or vertical) combination. EPA amended certain requirements to make them only applicable to Equation W-10A. In addition, EPA is clarifying that the flow rate and time determinations are for backflow during the completion or workover and not for when backflow is vented to the atmosphere or routed to flare. EPA is clarifying that the number of reduced emissions completions and the volume of gas recovered must be reported separately for well completions and workovers. EPA is also clarifying that emission vented directly to the atmosphere must be reported separately from emissions resulting from flaring of backflow gas from well completions and workovers with hydraulic fracturing.

Gas Well Venting During Completions and Workovers Without Hydraulic Fracturing. In this section we are revising the introductory text by deleting the term “well workovers not involving hydraulic fracturing” because it was repetitive. EPA also added a reference to 40 CFR 98.233(v) to convert CH_4 and CO_2 volumetric emissions to mass emission.

Second EPA is requiring reporting on a sub-basin level instead of a field level. Thus, the term “field” has been changed to “sub-basin” in the definition for the parameter “ N_{wo} ” and “ f ” in Equation W-13, consistent with the proposed change from “field” to “sub-basin” across subpart W. Additionally, we are revising the parameters and their respective definitions to correctly

represent standard conditions and not actual conditions. Finally, EPA is amending the summation operator in Equation W-13 to make it mathematically accurate. This includes adding the subscript “p”, which is an index for each completion without hydraulic fracturing in a sub-basin, and making specific parameters in Equation W-13 applicable to each well completion, “p”.

In the associated reporting requirements in 40 CFR 98.236 (c)(6)(ii), EPA clarified that only a total count of workovers that flare or vent gas to the atmosphere need to be reported. Additionally, EPA clarified that emissions from venting to the atmosphere and flaring must be reported separately.

Blowdown Vent Stacks. In this action, EPA is removing the term “equipment” and “equipment type” in 40 CFR 98.233(i) and replacing it with “unique physical volume” in this section. EPA also clarified the types of blowdowns covered. We are deleting the term “to atmosphere” because not every blowdown will result in the blowdown chamber being brought to atmospheric pressure, thus more fully portraying EPA’s intent to cover these types of “blowdowns.”

Next, we are clarifying that we only intend to cover the types of blowdowns typically activated by operators, whether for what an operator might perceive as an emergency shutdown or when taking equipment out of service for operational or maintenance purposes. The term “activated by operators” implies that an operator was present at the time the blowdown was activated, and that the operator(s) manipulated automated or manual controls to isolate the equipment and open the blowdown valve(s). Whether the operator perceived this human intervention to isolate and blowdown equipment as stemming from a perceived emergency or routine operational or maintenance functions is unimportant because the operator has full knowledge of the timing and equipment being isolated and blown down to record for reporting purposes. It was not EPA’s intent to capture automated releases that do not involve human intervention, such as pressure safety valve releases, pressure controlled venting, or compressors being automatically shut down for safety in the absence of operator presence or intervention. Such automated safety releases or equipment shutdowns may not have sufficient operator involvement to know the timing and exact nature of the gas release to make an accurate accounting.

Also in this action, we are revising the numbering of Equation W-14 to be Equation W-14A, and adding an Equation, W-14B. We are adding Equation W-14B to allow facilities to track blowdowns by each occurrence. Equation W-14B allows reporters to account for situations where a unique physical volume may not be blown down to atmospheric pressure.

For both equations, V_v has been changed to V . We are also clarifying that the parameter V is the actual physical volume of the blowdown equipment and not the gas volume. In both equations, the definition of parameter “N” has been changed to the number of times a particular unique physical volume is blowdown to the atmosphere. Finally, “ T_s ” has been set at 60 degrees Fahrenheit and “ P_s ” has been set at 14.7 psia.

Accordingly, revisions to 40 CFR 98.236(c)(7) were made to account for these amendments. We are revising the data reporting requirements for blowdown vent stacks by stating that emissions from unique volumes that are blowdown more than once during the calendar year must be reported by unique physical volume and the number of times that a particular volume is blowdown must be reported. For unique physical volumes that are blowdown only once during the calendar year, reporters can total the emission from all of the unique volumes and report an aggregate number. In addition, EPA added the requirement to report the number of unique volumes that are blowdown only once during the calendar year.

Onshore Production Storage Tanks. EPA is amending several provisions in 40 CFR 98.233(j) for calculating GHGs from onshore production storage tanks.

First, we are clarifying that the equipment threshold referenced throughout this section for onshore production storage tanks is based on an annual average daily throughput. This clarification was necessary to address ambiguity in the final rule regarding the determination of the throughput of oil.

Next, we are making corrections to address erroneous citations in 40 CFR 98.233(j)(1)(vii) and 40 CFR 98.233(j)(2).

Next, in this action, EPA is replacing the term “field” in 40 CFR 98.233(j)(1)(vii)(B), 40 CFR 98.233(j)(1)(vii)(C), and 40 CFR 98.233(j)(3)(i) with the term “sub-basin category” as per the discussion in Section II.C of the September 9, 2011 proposal preamble. EPA is also clarifying that reporting of CH₄ and CO₂ emissions determined using Calculation Methodologies 3 and 4 are on an annual basis.

We are revising Equation W-15 to include a multiplier of 1,000 that converts emissions from thousand standard cubic feet to standard cubic feet so the calculation results in accurate units. Also, we are amending the definitions of the parameters, EF_i and Count, to clarify that these parameters must be used for well-pad gas-liquid separators and for wells sending liquids straight to a tank without passing through any gas-liquid separators with throughput less than 10 barrels per day. Additionally, EPA is changing standard conditions to 60 degree Fahrenheit and 14.7 psia; therefore, the emission factors for CH₄ and CO₂ at 60 degrees Fahrenheit replaced the existing values at 68 degrees Fahrenheit.

Lastly, in Equation W-16, we are amending the definition for the parameter E_i by correcting the erroneous citations, 40 CFR 98.233(j)(3) and (j)(5), and including the accurate citations, 40 CFR 98.233(j)(1), (j)(2), and (j)(4), instead. We are including a conversion factor in this equation such that the emissions are being determined on a yearly basis, as opposed to an hourly basis. We are deleting the parameter E_i in the equation, because it is being accounted for in the revised equation and therefore is not necessary.

Accordingly, we are clarifying several data reporting requirements in 40 CFR 98.236(c)(8) for this source. First, for Calculation Methodologies 1 and 2. Next, for Calculation Methodologies 3, 4, and 5, vented, flared, and recovered emissions must be reported for each GHG and all requirements must be reported at a sub-basin level. Next, we are correcting an erroneous citation in 40 CFR 98.236(c)(8)(ii)(D). Finally, as proposed, EPA is adding the reporting of vented emissions for each gas at the sub-basin level for improperly functioning dump valves. This data reporting requirement is based on the inputs to Equation W-16 in 40 CFR 98.233(j) and therefore will not place additional burden on reporters.

Transmission Storage Tanks. EPA is amending several provisions in 40 CFR 98.233(k) for calculating GHGs from transmission storage tanks.

First, we are revising 40 CFR 98.233(k)(1) to include an additional provision for monitoring the transmission storage tank vapor vent stack. With this amendment, reporters can either screen their tanks first by using the optical gas imaging instrument for 5 continuous minutes and, if a leak is detected, measure the leak according to the provisions in 40 CFR 98.234 consistent with the 2010 final rule, or measure the tank vent vapors for 5

minutes either using a flow meter or high volume sampler, or alternatively a calibrated bag based on manufacturers specifications according to the provisions outlined in 40 CFR 98.234.

Next, EPA is clarifying that emissions, determined in 40 CFR 98.233(k)(2) and (k)(4), are on an annual basis. Next, in 40 CFR 98.233(k)(4)(i), we are deleting the erroneous citation to 40 CFR 98.233(j)(1). Lastly, in 40 CFR 98.233(k)(4)(ii), we are clarifying that flare stack calculation methodology from 40 CFR 98.233(n) should be used for emissions that are sent to a flare and not from the flare.

EPA is amending two associated data reporting requirements in 40 CFR 98.236(c)(9). We are clarifying that vented and flared emissions for each GHG, must be reported for each transmission storage tank. Additionally, we are finalizing the reporting of a unique name or ID number, as proposed, for each transmission storage tank as per the discussion in Section II.D of this preamble.

Well Testing Venting and Flaring. EPA is amending the calculation methodologies under this source to make them applicable to gas wells and to situations wherein production from a group of wells is routed through the same pipe. In particular, EPA is adding Equation W-17B which uses the production rate of a gas well to estimate well testing venting emissions from gas wells. Additionally, EPA is clarifying that both equations apply to one or more wells being tested.

EPA is amending the data reporting requirements in 40 CFR 98.236(c)(10), to clarify that for each GHG, reporters must report emissions from well testing venting and from well testing flaring separately. These emissions from well testing venting and well testing flaring are calculated individually in 40 CFR 98.233(l); therefore, this places no additional burden on reporters.

Associated Gas Venting and Flaring. EPA is revising 40 CFR 98.233(m)(1) to replace the term "field" with the term "sub-basin category" as per the discussion in Section II.C of the September 9, 2011, GHGRP Revisions Proposal.

EPA is amending the data reporting requirements in 40 CFR 98.236(c)(11), to clarify that for each GHG, reporters must report emissions from associated natural gas venting and from associated natural gas flaring separately. These emissions from associated natural gas venting and associated natural gas flaring are calculated separately in 40 CFR 98.233(m); therefore, this places no additional burden on reporters.

Flare Stack Emissions. EPA is amending several provisions in 40 CFR 98.233(n) for calculating GHGs from flare stacks.

First, we are amending 40 CFR 98.233(n)(2)(ii) to clarify that reporters of onshore natural gas processing plants that solely fractionate a liquid stream, must use the GHG mole percent in feed natural gas liquid for all streams. This amendment addresses the lack of clarity in the final provisions on how natural gas processing plants that only fractionate liquid streams would determine their gas compositions.

Next, we are revising 40 CFR 98.233(n)(2)(iii) to clarify that for any applicable industry segment, methane, in addition to ethane, propane, butane, pentane-plus and mixed light hydrocarbons, should be accounted for when the stream going to the flare is a hydrocarbon product stream. This correction ensures that the paragraph 40 CFR 98.233(n)(2)(iii) is consistent with the Equation W-21.

Next, we are clarifying the summation operator in Equation W-21 to make the equation mathematically correct. Additionally, we are clarifying, in 40 CFR 98.233(n)(11), that source types in 40 CFR 98.233 that send emissions to a flare and use Equations W-19 through W-21, must determine volumetric flow rate, parameter "V_a", in Equation W-19 through W-21, at actual conditions.

EPA did not intend to unnecessarily limit the measurement options for flares that operate and maintain a continuous emissions monitoring system (CEMS). EPA is now allowing the reporters to calculate CO₂ emissions from flares that operate and maintain a CEMS, using Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). This includes following the procedures for initial certification of the CEMS and the ongoing quality assurance requirements for the CEMS specified in 40 CFR 98.34(c). Also, EPA is exempting the reporting of CH₄ and N₂O emissions from flares that operate and maintain a CEMS.

EPA is making several amendments to the data reporting requirements in 40 CFR 98.236(c)(12). First, we are amending requirements to clarify that uncombusted CH₄ emissions, combusted CO₂ emissions, uncombusted CO₂ emissions, and combustion-related N₂O emissions must be reported separately. Second, we are adding the reporting of combined combusted and uncombusted CO₂ emissions from flares that operate and

maintain a CEMS. These uncombusted CH₄, combusted CO₂, uncombusted CO₂, combustion-related N₂O emissions, and combined combusted and uncombusted CO₂ emissions from flares that operate and maintain a CEMS are calculated separately in 40 CFR 98.233(n); therefore, these requirements place no additional burden on reporters. Lastly, we are finalizing the reporting of a unique name or ID number, as proposed, for each flare stack under onshore natural gas processing as per the discussion in Section II.D of this preamble.

Centrifugal Compressor Venting. EPA is finalizing amendments that were made across the sections in 40 CFR 98.233 to standardize reporting for standard conditions. First, EPA is clarifying two parameter definitions under this source. First, in Equation W-24, we are amending the definition of parameter MT_m to clarify that flow measurements must be determined in standard cubic feet per hour. Second, EPA is changing standard conditions to 60 degrees Fahrenheit and 14.7 psia; therefore, in Equation W-25, the emission factors for GHG_i at 68 degrees Fahrenheit were removed from the parameter EF_i.

Reciprocating Compressor Venting. EPA is finalizing amendments that were made across the section in 40 CFR 98.233 to standardize reporting for standard conditions. First, EPA is clarifying two parameter definitions under this source. First, in Equation W-28, we are amending the definition of parameter MT_m to clarify that flow measurements must be determined in standard cubic feet per hour. Second, EPA is changing standard conditions to 60 degrees Fahrenheit and 14.7 psia; therefore, in Equation W-29, the emission factors for GHG_i at 68 degrees Fahrenheit were removed from the parameter EF_i.

Leak Detection and Leaker Emission Factors. We are revising 40 CFR 98.233(q)(8) to remove the term "city gate stations at custody transfer" and replace with the term "transmission-distribution transfer stations" for the reasons described in Section II.C of the September 9, 2011 GHGRP Revisions Proposal. We are also removing the term "meters and regulators" and replacing these terms with above ground "metering-regulating stations".

EPA is revising equation W-30A, previously designated at W-30A in the November 2010 final rule (75 FR 74458), to clarify the summation operator to make it mathematically correct. This clarification includes amending the term "x" to be the count of each equipment leak source as listed in Table

W-7 and adding T_p , which is the total time the component p was found leaking and operational. We are also revising the parameter GHG_i . For industry segments listed in 40 CFR 98.230(a)(4) and (a)(5), GHG_i has been revised to 0.974 for CH₄ and 1.0×10^{-2} for CO₂. For industry segments listed in 40 CFR 98.230(a)(6) and (a)(7), GHG_i equals 1 for CH₄ and 0 for CO₂. For industry segments listed in 40 CFR 98.230(a)(8), GHG_i equals 1 for CH₄ and 1.1×10^{-2} CO₂.

EPA is adding the option in 98.233(q)(8)(A) for natural gas distribution facilities to conduct monitoring at their transmission-distribution transfer stations over a multiple year period, not exceeding five years. For more information on the comments received and EPA's response to this topic see Section II.D Responses to Major Comments submitted on the *Petroleum and Natural Gas Systems Source Category* of this preamble. Facilities that choose to use the multiple year option are required to conduct monitoring at roughly the same number of T-D stations over the cycle without repetition of the same T-D stations within the cycle.

EPA is also adding a new Equation W-30B to account for emissions from leaking sources at above ground T-D transfer stations when the facility chooses to conduct monitoring at T-D transfer stations over a multiple year cycle. Equation W-30B maintains a rolling sum of emissions from T-D transfer stations that have been monitored over the multiple years in the cycle and results in a rolling average in Equation W-32 for each meter/regulator run. EPA has also added three terms t, n, and $T_{p,q}$ that are in Equation W-30B. The term t defines the calendar year, n defines the number of years in the cycle over which all T-D transfer stations will be monitored, and $T_{p,q}$ defines the total time the leak source p was found leaking and operational in the multiple year cycle. Finally, EPA has clarified that Equation W-30A applies to facilities listed in 40 CFR 98.230(a)(3)-(a)(7) and Equation W-30B applies to facilities listed in 40 CFR 98.230(a)(8).

We are amending the data reporting requirements associated with the changes to 40 CFR 98.233(q) and (r) in 40 CFR 98.236(c)(16). We are revising the requirements based on the revisions to the data calculation methodologies for Local Distribution Companies that choose to use the 5-year rolling survey plan. These revisions include provisions for facilities to report the total number of T-D stations at their facility, the number of years over which all T-D transfer stations will be monitored at

least once, and the number of T-D stations that are being monitored in the calendar year. We are also amending the reporting requirements in 40 CFR 98.236(c)(16) to clarify that facilities must report CH₄ emissions collectively by emission source type and CO₂ emissions collectively by emission source type.

Population Count and Emission Factors. We are finalizing several amendments in 40 CFR 98.233(r). First we are amending the definition of EF_s in equation W-31 by replacing the term "non-custody transfer city-gate" with "meter/regulator runs" at above grade "metering-regulating stations" for the reason stated in Section II.C of the September 9, 2011 proposal. We are also clarifying that the count in equation W-31 applies to the number of "meter/regulator runs" at all "metering-regulating stations" combined.

We are also amending the term "count" in W-31 to elaborate and clarify how each industry segment should count the total number of equipment/components. In that same equation, for industry segments listed in 40 CFR 98.230 (a)(4) and (a)(5), we are revising GHG_i to 0.952 for CH₄ and 1.0×10^{-2} for CO₂. For industry segments listed in 40 CFR 98.230(a)(6) and (a)(7), GHG_i equals 1 for CH₄ and 0 for CO₂. For industry segments listed in (a)(8), GHG_i equals 1 for CH₄ and 1.1×10^{-2} CO₂.

Next, EPA is amending 40 CFR 98.233(r)(2)(i) to explicitly state how meters and piping are to be counted. Based on this amendment, owners or operators should use one count of meters/piping per well-pad.

Further, EPA is amending 40 CFR 98.233(r)(6)(i) by replacing the term "below grade meters and regulators" with the term, "below grade metering-regulation stations". EPA is also amending 40 CFR 98.233(r)(6)(ii) by referring to "metering-regulating stations" in place of "city gate" and to clarify that the emission factor for meter/regulator runs at all metering-regulating stations in Equation W-32 is based on "transmission-distribution transfer stations" that were monitored over the years that constitute one complete cycle per 40 CFR 98.233(q)(8)(A).

Lastly, we are revising Equation W-32 by revising definitions to EF , $E_{s,i}$, and "Count" to reflect the change in terminology from "custody transfer" for above ground "metering-regulating" stations. We are also revising Equation W-32 to include a conversion factor to convert to hourly emissions. Also, equation W-32 is amended in 40 CFR 98.233(r) so that the equation yields an

EF in cubic feet per meter per hour to be used in Equation W-31 for above ground metering-regulating stations. Finally, the summation operator has been removed in Equation W-32 because $E_{s,i}$ represents annual volumetric GHG_i emissions at all T-D transfer stations, making the summation operator redundant.

Volumetric Emissions. We are amending several provisions in 40 CFR 98.233(t). First, we are clarifying that reporters must calculate natural gas volumetric emissions at standard conditions by converting natural gas volumetric emissions at actual temperature and pressure to standard temperature and pressure. Next, the phrase "by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas" in 40 CFR 98.233(t)(2) was deleted because of redundancy. Next, EPA has changed standard condition to 60 degrees Fahrenheit and 14.7 psia; therefore, in Equations W-33 and W-34, EPA is including these standard temperature and pressure values for T_s and P_s . Lastly, EPA is providing a ratio of 519.67/527.67 to convert volumetric emissions from 68 °F to 60 °F for reporters using 68 degrees Fahrenheit for standard temperature.

GHG Volumetric Emissions. We are amending several provisions in 40 CFR 98.233(u). First, we are clarifying that reporters may determine the mole fraction of GHGs in natural gas by engineering estimate based on best available data unless EPA is requiring another method. Next, we are clarifying that when using a continuous gas composition analyzer, reporters must use an annual average of the values to determine the GHG mole fraction in produced natural gas. In addition, when reporters are not using a continuous gas composition analyzer, reporters must use an annual average gas composition based on the reporter's most recent available sample analysis of the sub-basin category or facility, depending on the emission source, instead of the actual most recent gas composition based on available analysis in a sub-basin entity.

Next, we are amending 40 CFR 98.233(u)(2)(ii) to clarify that reporters of onshore natural gas processing plants that solely fractionate a liquid stream, must use the GHG mole percent in feed natural gas liquid for all streams. This amendment addresses the lack of clarity in the final provisions on how natural gas processing plants that only fractionate liquid streams would determine their gas compositions.

We are amending 40 CFR 98.233(u)(2)(iii) through (u)(2)(vii), to include 95 percent methane/1 percent CO₂ default gas composition for the natural gas transmission compression, underground natural gas storage, LNG storage, and natural gas distribution industry segments and for LNG export facilities that receive gas from transmission pipelines unless specified otherwise in the Calculations for GHGs sections. Lastly, we are replacing the term “field” with the term “sub-basin category” as per the discussion in Section II.C of the September 9, 2011.

GHG Mass Emissions. We are amending several provisions in 40 CFR 98.233(v). First, we are removing the phrase “at standard conditions” from the introductory text and the subscript “s,” and the word “standard” from the definition of parameter $Mass_{s,i}$ because mass emissions do not need to be reported at standard conditions. Next, we are revising the definitions of parameters in Equation W-36 to clarify that the equation also applies to N₂O emissions. N₂O emissions are calculated from stationary combustion and flares, and this edit is needed to convert the mass emissions of N₂O to carbon dioxide equivalents of gas. Lastly, EPA has changed standard conditions to 60 degree Fahrenheit and 14.7 psia; therefore, the density values for CH₄, CO₂, and N₂O at 68 degrees Fahrenheit were removed from the parameter ρ_i .

EOR injection pump blowdown. We are amending two parameters in Equation W-37. First, we are removing the subscript “c” from the parameter $Mass_{c,i}$ and the phrase “at critical conditions” from the definition of parameter $Mass_{c,i}$ because mass emissions do not need to be reported at critical conditions. Second, we are amending the parameter GHG_i and $Mass_{c,i}$, to read GHG_{CO_2} and $Mass_{s,CO_2}$, to clarify that Equation W-37 only calculates CO₂ emissions.

EPA is clarifying the data reporting requirements in 40 CFR 98.236(c)(17) to state that annual emissions for each GHG, must be reported for each EOR pump.

EOR hydrocarbon liquids dissolved CO₂. We are amending the parameter $Mass_{s,CO_2}$ by removing the subscript “s” and the phrase “at standard conditions” from the definition of parameter $Mass_{s,CO_2}$ because mass emissions do not need to be reported at standard conditions.

EPA is clarifying the data reporting requirements in 40 CFR 98.236(c)(18) to state that all parameters, including annual CO₂ emissions, must be at a sub-basin level.

Onshore Production and Distribution Combustion Emissions. EPA is making several amendments to the provisions in 40 CFR 98.233(z).

First, we are clarifying that Calculation Methodologies in 40 CFR 98.233(z)(1) and (z)(2) apply to all stationary or portable equipment except external fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr. In addition, 40 CFR 98.233(z)(1) and (z)(2) apply to all internal fuel combustion sources, with a rated heat capacity equal to or less than 1 mmBtu/hr (not compressor-drivers). EPA is clarifying that for units below the 5 mmBtu/hr and 1 mmBTU/hr threshold, outlined in 40 CFR 98.233(z)(3) and (z)(4), reporters do not need to report combustion emissions or include these emissions for threshold determination in 40 CFR 98.231(a). Instead, reporters must report the type and number of each external fuel combustion unit and each internal fuel combustion unit below the equipment threshold.

EPA is clarifying when owners or operators of onshore production and distribution facilities must use the methods in 40 CFR subpart C to calculate combustion-related emissions and when they must use methods outlined in 40 CFR 98.233(z) to calculate combustion-related emissions. EPA is clarifying that facilities using subpart C to calculate emissions can use any Tier listed in subpart C. Regardless of the Tier used, facilities must follow the corresponding calculation, quality assurance, reporting, and recordkeeping requirements of that Tier.

EPA is amending the requirements for units combusting field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet. In this action, EPA is allowing the use of company records for the purposes of calibration for this equipment.

Next, EPA is including an engineering equation, W-39B, to determine the annual CH₄ emissions from portable or stationary fuel combustion sources. We are also clarifying the summation operator to make the existing equation, W-39A that calculates annual CO₂ emissions from portable or stationary fuel combustion sources, mathematically accurate. Additionally, we are also including a combustion efficiency parameter in Equation W-39A.

We are making several amendments to Equation W-40. First, we are changing the parameter N₂O to $Mass_{N_2O}$ because this equation calculates the annual N₂O

mass emissions from the combustion of a particular type of fuel. Second, we are amending an incorrect exponent to account for the conversion factor from kilograms to metric tons. Lastly, we are providing actual values in the definition of parameter HHV in Equation W-40.

Accordingly, EPA is amending the data reporting requirements in 40 CFR 98.236(c)(19) for external fuel combustion sources with a rated heat capacity greater than 5 mmBtu/hr, and internal fuel combustion sources (excluding a compressor-driver), with a rated heat capacity equal to or less than 1 mmBtu/hr, and internal fuel combustion sources. First, we are clarifying that for external fuel combustion sources with a rated heat capacity larger than 5mmBtu/hr, the emissions for each GHG must be reported by type of unit. Second, we are clarifying that for internal fuel combustion sources, with a rated heat capacity equal to or less than 1 mmBtu/hr (excluding a compressor-driver), only the cumulative number of units must be reported by type of unit. Lastly, we are clarifying that for internal fuel combustion units, the emissions for each GHG must be reported by type of unit.

Monitoring and QA/QC Requirements. We are finalizing several amendments to the monitoring and QA/QC requirements in 40 CFR 98.234.

First, we are amending the language in 40 CFR 98.234(a)(1) by removing and reserving the text in 40 CFR 98.234(a)(4) and combining it with 40 CFR 98.234(a)(1), thus resulting in one consolidated paragraph for optical gas imaging instrument provisions. We are also explicitly stating exceptions to the requirement under the Alternative work practice for monitoring equipment leaks. Those exceptions are (1) the monitoring frequency is annual and (2) the detection sensitivity is 60 grams per hour. In addition, EPA is requiring that the gas chosen during the instrument check must be methane. Finally, EPA is clarifying that video recordings are not required to be retained for the purposes of 40 CFR part 98, subpart W.

Next, we are amending the language in 40 CFR 98.234(a)(2) to state that Method 21 compliant instruments may be used to monitor inaccessible emissions sources. It is not EPA's intent here to require reporters to use unsafe methods to reach inaccessible emission sources using Method 21 compliant equipment. Rather EPA is allowing the use of Method 21 compliant leak detection equipment where the reporter can access inaccessible sources using safe options, such as the use of a bucket truck. EPA still requires the use of

optical imaging cameras to reach inaccessible emission sources where the reporter cannot use Method 21 compliant leak detection equipment safely. EPA allows the use of method 21 for all source types, although an optical gas imaging instrument must be used in cases where a reporter deems a source type inaccessible. EPA expects the reporters will use an optical gas imaging instrument in order to ensure safety when monitoring inaccessible source types. Lastly, based on questions raised by industry, we are clarifying in 40 CFR 98.234(a)(5) the type of acoustic leak detection devices that may be used. In particular the “gun” type instrument, which is aimed at the equipment from a distance to detect the acoustic signal of leakage, is not an allowable instrument under this rule. This type of equipment cannot distinguish between external leakage to the atmosphere and internal, through-valve leakage, which acoustic leak detection devices are used for under this rule. EPA is also further specifying that the “stethoscope” type acoustic detector that senses through valve leakage when put in contact with the valve body, but does not have the leakage estimating correlations, is permissible for leak detection only under this rule.

We are including an editorial revision in 40 CFR 98.234(c) for calibrated bagging to specify that those using the calibrated bag for sampling, must ensure that the emissions are at a temperature below which the bag manufacturer specifies for safe handling. EPA is also clarifying in 40 CFR 98.234(d)(3) that emission volumes determined using the high volume sampler can be converted to standard conditions using 40 CFR 98.233(t). Finally, we are revising Equation W-41 to insert missing variables “a” and “b” from the Peng Robinson equation.

Data Reporting Requirements. The amendments to the reporting requirements for various emission source types are discussed under the corresponding emission source paragraphs in this section of the preamble. Additionally, EPA is making the following amendments to the general reporting requirements in 40 CFR 98.236.

First, we are amending 40 CFR 98.236(b) to clarify that facilities reporting under the offshore petroleum and natural gas production industry segment must report emissions for each GHG, as applicable to the source type, for each emissions source type listed in the most recent Bureau of Ocean Energy Management and Regulatory Enforcement (BOEMRE) study.

Next, we are clarifying that if a facility operates under more than one industry segment, reporters must report the data from each piece of equipment under the industry segment in which the equipment is most used. Additionally, we are clarifying that if a source type routes gas to a flare, reporters must report vented and flared emissions separately for each gas. These vented and flared emissions must be reported under the respective source type and not under the flare stack source type.

Finally, EPA is including the reporting of average API gravity of the hydrocarbon liquids produced, average gas to oil ratio, and average low pressure separator pressure per oil sub-basin category for onshore production reporters.

Records that must be retained. EPA is clarifying that records that must be retained under 40 CFR 98.3(g)(2)(i) of the general provisions must include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart. This requirement is already included in 40 CFR 98.3(g)(2)(i) and including this requirement in Subpart W provides further clarity on the records facilities are required to keep.

Definitions. EPA is amending several definitions in 40 CFR 98.238, and in some cases, adding and removing definitions in 40 CFR 98.238.

Associated With a Single Well-Pad. We are including a definition for “associated with a single well-pad” to clearly demarcate the extent of the boundary of onshore production facilities. This definition more clearly expresses EPA’s intent that the association be defined by the hydrocarbon stream from one or more wells located on a single well-pad. Where the point of combination is located off that single well-pad, the association with a single well-pad ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads. Storage tanks located on a well pad are considered part of the onshore production industry segment.

Distribution Pipeline. We are adding a definition for distribution pipelines to clarify our intent for coverage for the natural gas distribution industry segment.

Facility With Respect to Natural Gas Distribution. We are revising the definition for facility with respect to natural gas distribution by replacing the term “metering stations, and regulating” with the term “metering-regulating” and by clarifying that the collection of all distribution pipelines and metering-

regulating stations operated by an LDC within a single state must be included.

Facility With Respect to Onshore Petroleum and Natural Gas Production. We are revising the definition for facility with respect to onshore production by clarifying that it includes all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO₂ EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238.

Farm Taps. We are revising the definition for farm taps in 40 CFR 98.238 by removing the statement “[t]he gas may or may not be metered, but always does not pass through a city gate station” as this statement is unnecessary.

Flare. We are adding a definition of flare, specific to subpart W, to address questions received during implementation of the 2010 final rule about what constitutes a flare. This definition clarifies that a flare may be either at ground level or elevated and that a flare may use an open or enclosed flame to combust waste gases without energy recovery. The intent of this definition is to include devices that combust waste gases without energy recovery.

Forced Extraction of Natural Gas Liquids. We are adding a definition for forced extraction, as proposed, to limit the use of forced extraction to specific processes. With this definition, EPA is clarifying that “forced extraction of natural gas liquids” means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes.

Gas Well. We are removing the definition of gas well from 40 CFR 98.238. Gas wells are defined within the revised definition of sub-basin category.

Horizontal Well. We are including a definition for horizontal well in conjunction with the change from field level reporting to sub-basin category. With this definition, we are stating that a horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in

parallel with and through the target formation.

Metering-regulating Station. We are adding this definition to clarify that metering-regulating stations are stations that meter the flowrate, regulate the pressure, or both, of natural gas in a natural gas distribution facility. These do not include customer meters, customer regulators, or farm taps.

Natural Gas. We are adding this definition, as proposed, to clarify that natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Additionally, we are clarifying that natural gas may be field quality, pipeline quality, or process gas.

Oil Well. We are removing the definition for oil well from 40 CFR 98.238. Oil wells are defined within the revised definition of sub-basin category.

Pressure Groups. We are adding a definition of pressure groups, as proposed, as applicable to each sub-basin to clarify that pressure groups are: Less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig. The pressure in the context of pressure groups is either the well shut-in pressure; well casing pressure; or you may use the casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure for each well in the sub-basin.

Sub-Basin Category. We are including a definition for a sub-basin category in conjunction with the change in measurement from field to sub-basin level. Based on this definition, a sub-basin means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce from high permeability gas, shale gas, coal seam, or other tight reservoir rock are considered gas wells; gas wells producing from more than one

of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

Transmission-Distribution (TD) Transfer Station. As proposed, EPA is adding a definition for Transmission Distribution (TD) transfer station to define what was previously termed "custody transfer" in the final rule. This definition was necessary to further clarify EPA's intent, which was not for the term "custody transfer" to be defined in the context of ownership of gas transfer. The TD transfer station means a meter-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission Pipeline. We are finalizing a definition as proposed for transmission pipeline to clarify that transmission pipelines are clearly designated as such by the Federal Energy Regulatory Commission for interstate transmission pipelines, individual States for intrastate transmission pipelines, and the Hinshaw exemption under the Natural Gas Act for Hinshaw transmission pipelines.

Tubing diameter groups. We are finalizing a definition for tubing diameter groups, as proposed, to clarify that tubing diameter groups are: less than or equal to 1 inch; greater than 1 inch and less than 2 inch; and greater than or equal to 2 inch.

Tubing systems. We are finalizing a definition of tubing systems, as proposed, to clarify that tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

Vertical Well. We are finalizing a definition for vertical wells, as proposed, to coincide with the change from field level reporting to sub-basin category, EPA is adding a distinction for calculating emissions from horizontal wells and vertical wells. With this definition, a vertical well means a well bore that is primarily vertical but might have some unintentional deviation or one or more unintentional deviations to enter one or more subsurface targets that are off-set horizontally from the surface

location, intercepting the targets either vertically or at an angle.

Well Testing Venting and Flaring. We are finalizing, as proposed, a definition for well testing venting and flaring. This definition says that well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined (*i.e.*, the well testing) through a choke (an orifice restriction). Based on this revised definition, if well testing is conducted immediately after well completion or workover then it would be considered part of a completion or workover.

Emission Factor Tables. We are amending several emission factors in subpart W in response to comments requesting that the emission factors be adjusted to reflect a consistent standard temperature and pressure used for calculation methodologies in 40 CFR 98.233. Specifically, we are revising all of the entries to 60 degrees Fahrenheit for Tables W-1A and W-2 through W-6 and revising the entries for "Low Continuous Bleed Pneumatic Device Vents", "High Continuous Bleed Pneumatic Device Vents", and "Intermittent Bleed Pneumatic Device Vents" to whole gas emission factors in Table W-1A. Additionally, we are revising the entries for "Leaker Emission Factors—Transmission-Distribution Transfer Station Components, Gas Service," "Population Emission Factors—Below Grade Metering-Regulating Station Components, Gas Service," "Population Emission Factors—Distribution Mains, Gas Service," and "Population Emission Factors—Distribution Mains, Gas Service" to 60 degrees Fahrenheit.

D. Responses to Major Comments Submitted on the Petroleum and Natural Gas Systems Source Category

This section contains a brief summary of major comments and responses on the proposed amendments to subpart W published in GHGRP Corrections Proposal and the GHGRP Revisions Proposal. Responses to additional comments received on those proposals can be found in the document, "Mandatory Reporting of Greenhouse Gases—Technical Revisions to the Petroleum and Natural Gas Systems Category of the Greenhouse Gas Reporting Rule: EPA's Response to Public Comments" see docket EPA-HQ-OAR-2011-0512.

1. Pressure groupings

Comment: EPA received comments requesting two pressure ranges for calculating emissions from liquids unloading of gas wells in 40 CFR 98.233(f) as opposed to the September 9,

2011 proposal, which proposed five pressure ranges, four bounded ranges between 0–200 psig and one unbounded range above 200 psig, for this source. Commenters also requested clarification as to whether the proposed pressure ranges would apply across the sub-basin, including both conventional and unconventional wells. Finally, commenters were unclear as to what pressure types were to be used for the pressure groupings, and requested clarification as to whether the groupings were based on surface pressure or a different type of pressure.

Response: In response to the commenters first point, EPA has concluded that the five pressure ranges finalized in this action are appropriate for methodology 1 of 40 CFR 98.233(f). Greenhouse gas emissions resulting from well liquids unloading, regardless of what type of reservoir or gas well is involved, must be reported in the pressure range based on shut-in pressure as defined in 40 CFR 98.238 Definitions, Pressure Group. To avoid confusion, EPA is discontinuing the use of the terms “conventional” and “unconventional” because these terms have different meanings within the industry. The volume of gas released during an unloading is directly related to the wellhead pressure. EPA analyzed different numbers of pressure groupings and selected the optimal number of pressure groupings that resulted in minimal error while managing burden. In this action, reporters are to estimate emissions from one well with a unique tubing diameter grouping and pressure grouping combination in a sub-basin, and apply that value to all wells with that tubing diameter grouping and pressure grouping in that same sub-basin.

Please refer to the Pressure Analysis document in EPA–HQ–OAR–2011–0512–0016 for background on the analysis. EPA evaluated several different pressure groupings and their appropriateness to this emissions source, including the option suggested by the commenter, of two pressure groupings. Based on EPA’s analysis documented in the memo to the docket, industry’s suggestion of using only two pressure groupings would not provide the sufficient amount of accuracy in characterizing similar wells in the same sub-basin. Based on the five pressure groupings, EPA estimates that the minimum error would be about 30 percent from all wells that would report. However, if the number of ranges were reduced to 2 pressure groupings then the minimum error that would result from all wells is about 65 percent. These error estimates are based on theoretical

calculations, not accounting for error in meter reading and human error. Given the large error in the two pressure grouping scenario, EPA has determined that a 5 pressure grouping is the optimal for balancing burden to monitor versus the quality of data required to inform policy.

To address the commenter’s question about whether or not the five pressure groupings would apply to emission sources other than the liquids unloading emission source, EPA believes that final the provisions provide sufficient clarification. In particular, EPA has clarified in 40 CFR 98.233(f) that the five pressure groupings apply to the liquids unloading emissions source only. Furthermore, EPA has added a definition for pressure groupings in 40 CFR 98.238 to explicitly state what those pressure groupings apply to the liquids unloading emission source. Pressure groupings apply only to gas wells for liquids unloading as specified in 40 CFR 98.233(f), and do not apply to the oil sub-basin formation.

Finally, in response to the commenters’ request for clarity as to what types of pressures are used in the pressure grouping, EPA has finalized a definition for pressure groupings that clarifies that the well shut-in pressure just before liquids unloading, well casing pressure just before liquids unloading, or casing to tubing pressure of one well just before liquids unloading from the same sub-basin can be used for the pressure groupings.

2. Data Reporting Requirements of 40 CFR 98.236(e)

Comment: EPA received comments on data reporting requirements for sub-basins in 40 CFR 98.236(e), specifically that API gravity, average gas to oil ratio and average low pressure separator pressure are not available or appropriate for applications to each of the sub-basin categories. The commenters assert for example, that dry gas production areas, such as coal-bed methane, will not have API gravity or gas to oil ratios to report for a sub-basin. Commenters further noted that this reporting requirement is applicable only to an oil production sub-basin category.

Response: EPA agrees and has amended 40 CFR 98.236(e) to clearly indicate that only onshore petroleum and natural gas production reporters must report the average API gravity of their hydrocarbon liquids produced and the average gas to oil ratio per the oil formation sub-basin entity as defined in 40 CFR 98.238.

In September 2011, EPA proposed additional data reporting requirements for onshore petroleum and natural gas

production reporters to report the average API gravity of the hydrocarbon liquids produced, average gas to oil ratio, and average low pressure separator pressure per sub-basin entity. With the exception of the low pressure separator pressure, this information is already known to operators. In order to pay royalties and taxes, producers routinely conduct analyses on their produced crude oil to determine the gas to oil ratio and API gravity. Therefore, EPA has determined that this requirement would impose no additional burden on the industry.

3. Unique Name or ID Reporting Requirements

Comment: Several commenters representing the transmission compression industry segment noted that the proposed requirement to report unique ID’s for the transmission storage tank source type would not provide meaningful information and that the requirement was inappropriate because it did not apply to the monitored source. Furthermore, these commenters noted that in some cases, multiple tanks are linked to a single vent, and having a requirement to report a unique ID for each tank would not be useful, since the vent, not the tank, is the monitored source. These commenters stated that this requirement should be removed from the final rule.

Response: EPA agrees with the commenters, in part, and has revised the data reporting requirements for the transmission storage tank emissions source in 40 CFR 98.236 to more appropriately track the emissions at the vent and not the tank. In this action, 40 CFR 98.236(c)(9)(iii) has been clarified to state that a unique name or ID shall be assigned to the vent line.

To meet the requirements of the 2010 final rule, which require reporting for each tank, owners and operators need to have a mechanism for tracking emissions from each storage tank. Further, to meet the reporting requirements, and requirements for resubmission of an annual GHG report in the event that EPA or the facility owner or operator identifies a substantive error (see 40 CFR 98.3(h)), owners and operators need to have a mechanism to assign the emissions they reported from an individual tank to the entry that they include in the electronic GHG Reporting tool (e-GGRT) for that same tank. For this reason, EPA has determined that the assignment of a unique ID is not new, nor does it introduce any new requirement that was not already required by the 2010 final rule. Rather this addition is providing clarification of the existing reporting

requirements. Therefore, in this action, EPA is finalizing the requirement to report a unique name or ID number for vents in transmission storage tanks in 40 CFR 98.236(c)(9), as well as glycol dehydrators in the natural gas processing industry segment in 40 CFR 98.236(c)(4), acid gas removal vents in the natural gas processing industry segment in 40 CFR 98.236(c)(3), and flare stacks in the onshore natural gas processing industry segment in 40 CFR 98.236(c)(12). EPA is also finalizing the requirement to report the unique name or ID for the unique physical volume for blowdowns in 40 CFR 98.236(c)(7) for transmission compression, gas processing, and LNG import and export industry segments.

To address the commenters' comment that the unique name or ID is unnecessary for the transmission storage tanks emission source, EPA believes that this information is critical and has finalized this provision for other emissions sources including the flare emissions source and for unique blowdown physical volumes. In addition, EPA believes that these particular emission sources are not mobile and are generally stationary at a given facility. For example, for a source such as transmission storage tanks, the unique ID would inform EPA on where emissions are occurring, and over a time period of several years, would inform the Agency of the emissions trends associated with that particular emissions source at the facility.

Comment: EPA received comment specific to the reporting of a unique name or ID for the gas to liquid separators in the onshore production industry segment. Commenters noted that the proposed requirements to report unique ID will have no impact on the current emissions inputs or data quality, and are contradictory to industry's efforts to work with EPA to complete an accurate GHG inventory within a manageable reporting burden and resources. Additionally, the commenter asserted that creating unique equipment identifiers neither adds to the level of accuracy of calculated emissions, nor does it provide information that is not already available through the currently reported individual equipment counts and reported CO₂ and CH₄ emissions totals that are already part of the GHGRP. In onshore production, the commenter contends that the identifier data requested by EPA will not be usable at the individual equipment level due to the dynamic nature of the sector and the fact that the identifiers may be tied to well names or locations and hence be different every year due to frequent equipment movement, change-

outs and replacements that routinely occur at oil and gas well sites.

Response: EPA agrees that for the onshore production segment, a unique name or ID number may be difficult to assign for portable equipment that may move from one location to another.

EPA initially proposed data reporting requirements of unique name or ID number in the onshore production industry segment for the following emission sources; acid gas removal units, glycol dehydrators, wellhead separators or storage tanks, flare stacks, and EOR injection pumps. However, after evaluating the comments received, EPA believes that reporting of these particular emission sources in the onshore production industry segment, which has a definition of facility at the basin level, would be sufficient without a unique name or ID, although some information to track emissions from specific pieces of equipment over time could be lost, because the data will ultimately be reported at the facility level. EPA agrees with the commenter that tracking of a particular emission source that may be moved from one site to the next may pose a problem to certain reporters who would find it difficult to track an emission source to this level. Onshore producers may often replace equipment in a process with other equipment either for maintenance purposes or to size the equipment as the well production rate varies over time. Given these issues that are unique to onshore production segment, therefore EPA is not requiring unique name or ID number in onshore production. EPA recognizes that removing this requirement for onshore production could potentially result in the loss of equipment-specific information that could be useful for future policy analysis and we may continue to evaluate this for future rulemakings.

4. Transmission-Distribution Transfer Station Reporting

Comment: Commenters generally agreed with the proposed definition for transmission-distribution transfer station proposed in the GHGRP Revisions Proposal. However, commenters stated that the proposed definition for transmission-distribution transfer station would require many more stations to be included in the leak detection survey requirement, and that it would be an unreasonable burden. In addition, commenters noted that the stations that would be surveyed are small and remote stations and this would lead to an added burden to survey for leaks. Finally, commenters urged EPA to adopt a threshold to exclude small stations from monitoring

for GHG emissions. One commenter, specifically noted that one of their member companies completed surveys of 162 stations in 2011, and out of 32,400 components measured, only 18 leaking components were found. The commenter noted that they surveyed their members in October 2011 and received responses from 42 larger member LDCs. Of those 42 LDCs, that the commenter stated that a total of 20,781 stations would appear to fall within the final definition for transmission-distribution stations. One commenter specifically suggested having a percentage of the stations report and using that percentage to forecast emissions for the other stations. Further, several other commenters suggested using a threshold to reduce the number of leak surveys required.

Response: EPA notes that the number of reporters (*i.e.*, LDCs) that EPA estimated would be reporting under the natural gas distribution industry segment under subpart W has not changed. Because this industry segment has a high level of uncertainty in the context of knowing the exact number of stations that would be covered under the rule, EPA would like to note that based on the limited information submitted by the commenter, it could be a possibility that the number of stations covered under the subpart W rule (75 FR 74458) between the 2010 final rule and what is being finalized in this action may have increased. It was not EPA's intent to increase the number of surveys required. Therefore, after considering the two suggestions by commenters, EPA is finalizing an option that would allow facilities to conduct a leak detection survey once in any five consecutive calendar years for each station. EPA added the five consecutive year leak detection period to potentially coincide with reporters' existing inspection requirement under DOT regulations. Therefore, the annual burden to reporters will not increase as a result of this revision. See Transmission-Distribution Transfer Station docket memo in docket #EPA-HQ-OAR-2011-0512.

In this action, EPA is amending 40 CFR 98.233(q)(8) by allowing each above grade transmission-distribution transfer station the option to conduct a leak detection survey at least once in any five consecutive calendar years, with a minimum of 20 percent of their total number of stations being leak surveyed annually. Reporters choosing to use this option would use a five-year rolling average of their transmission-distribution transfer station leaking component counts to calculate emissions. In accordance with the

calculation requirements, these reporters would also define in their monitoring plan how the annual leak surveys represent cross sections of the total number of stations.

Furthermore, EPA evaluated Department of Transportation (DOT) regulations for comparison in the context of monitoring frequency. As provided in the November 2010 docket memorandum "Understanding the Substance of DOT Regulations and Comparing Them to the Subpart W Requirements," DOT requires leak detection surveys annually for more populated areas and every five years for less populated locations. Although the DOT regulations covering various stations are not duplicative of EPA regulations under the Greenhouse Gas Reporting Program, providing the option to align the survey frequencies for both requirements may reduce burden for some reporters. EPA added the five consecutive year leak detection period to potentially coincide with reporters' leak inspection requirement under DOT regulations in order to give reporters the opportunity to fulfill Subpart W requirements during the regular DOT survey or maintenance visit.

In response to the commenters' assertion that the final definition for transmission-distribution transfer stations disproportionately covers stations that are small and remote, and in response to the commenters' suggestion to implement a threshold by which small stations would be exempt from being surveyed for leaks, EPA disagrees that the size of the station should impact whether leaks are surveyed because small stations in remote locations are potentially large sources of emissions, for example, due to aging equipment and or potentially infrequent operator maintenance.

DOT regulations focus on public safety, and as such facilities near business districts are inspected annually. Conversely, facilities farther away from business districts may be inspected less frequently and receive less frequent and less consistent maintenance attention, increasing the chance that small or remote facilities are large emitters. Therefore, EPA decided not to exclude remote stations. In this action, EPA is finalizing an option for transmission-distribution transfer stations that allows for surveying stations over a five-year period as opposed to surveying all stations annually. Thus the annual burden is not increased and the necessary data is collected over a longer period of time.

5. Associated With a Single Well-Pad

Comment: EPA received several comments requesting clarification on the intent of the proposed definition of "associated with single well-pad" in 40 CFR 98.238. Commenters submitted several diagrams depicting various configurations of equipment associated with the onshore production industry segment and requested EPA's confirmation of their understanding of which types of equipment would fall under the definition for "associated with a well-pad."

Response: In the proposed rule, the definition stated that onshore production storage tanks off of a well pad were included in the equipment that was considered to be associated with a well pad. After considering the comments received, EPA is amending the proposed definition of "associated with a single well-pad" in 40 CFR 98.238 to clarify that onshore production reporters do not report emissions from separators or tanks that receive oil from combined streams from multiple well-pads that are not on a single well-pad or associated with a single well-pad. However, under 40 CFR 98.233(j), onshore production reporters must report emissions from separators or tanks that are on a single well-pad or associated with a single well-pad.

6. Equipment Threshold for Internal Combustion Engines

Comment: In the GHGRP Revisions Proposal, EPA solicited comments on whether a 1 MMBtu/hr is sufficient to exclude all temporary and small (not compressor-drivers) internal combustion equipment. EPA received comments stating that a similar threshold to that which was in the 2010 final rule for external combustion devices should be applied to all internal combustion devices. Several commenters representing the natural gas distribution industry segment agreed with the proposal, but requested that the 1 mmBtu/hr threshold also be applied to natural gas engines. Further, commenters representing the onshore production industry segment noted that lease fuel is reported by the Energy Information Administration (EIA) which could be used to sufficiently characterize combustion emissions from devices on well pads and therefore internal combustion devices below 5 MMBtu/hr should not be required to be reported.

Response: EPA disagrees that a threshold of 5 MMBtu should be applied to internal combustion devices, as was done for external combustion devices in the November 2010 final rule

for subpart W. In this action, EPA is finalizing a threshold of 1 MMBtu/hr threshold in 40 CFR 98.233(z) for internal combustion equipment. EPA has also clarified in the final provisions for this rule that this 1mmBtu threshold does not apply to compressor-drivers.

In considering potential equipment thresholds for internal combustion engines (not compressor-drivers), EPA collected and reviewed data on the horsepower rating of small, portable internal combustion engines that may be brought to a wellhead for periodic maintenance and construction. Such equipment can include electric generators for arc welding, electric generators powering portable flood-lighting, and electrical generators or gasoline engines powering air compressors (for sand blasting or pneumatic tools). For lighting, the industrial generators were almost exclusively below 12 horsepower (hp), with the highest found being 13.9 hp. For welding machines, we assumed that operators would use standard portable generators, since specific information on these types of machines was scarce. Most portable industrial generators are rated between 15–40 hp, with the largest one found being 67 hp. As a result, EPA determined that a 1 mmBtu/hour threshold, which equates to 393 hp, will exclude these smaller internal combustion devices. EPA has also determined that a 1 mmBtu/hour threshold may exclude a significant number of internal combustion engines on wellhead compressors, and is thus not applying this threshold to compressor-drivers. The equipment that would be excluded, if the threshold were raised above 1 mmBtu could include drilling rigs, workover rigs and hydraulic fracture pump engines, for example. EPA deems it necessary to collect data on these compressors to inform future policy because they are potentially large source of emissions and also there is not sufficient and reliable data available on these types of emissions sources. In response to the commenters' assertion that the information is reported by the EIA and therefore is not necessary to be reported under the greenhouse gas reporting rule, the EIA data is reported on a voluntary basis and the requirements for reporting are not standardized. As a result, the data available through EIA is not sufficiently accurate to exclude combustion devices from reporting.

Regarding the Commenters' request for the same 5 mmBtu/hour threshold for internal combustion as applied to external combustion, EPA is not accepting this change, because it could potentially exclude virtually all

wellhead compressors and engines, including those associated from drilling rigs which are large sources of GHG emissions. Comments on the subpart W proposed rule (75 FR 18608) included detailed itemization of heaters on tanks, separators, dehydrators and pipelines, often for winter freeze protection, with estimated numbers of these external combustion devices. From this information, EPA developed the 5 mmBtu/hour threshold to exclude reporting of emissions from these many sources which are not necessarily operated all year long and for which detailed records are not maintained on when winter heating is turned on and off, often by automated temperature controls. Similar data was not provided for internal combustion engines, and EPA does not have a good public record of the number of these engines or their typical duty.

7. Reporting 2011 Data Under Amended Rule

Comment: Several commenters requested that EPA resolve certain areas of uncertainty for calendar year 2011 data collection in the context of when the proposed revisions and technical corrections would be finalized for 40 CFR part 98, subpart W. Specifically, API raised concerns about two emissions sources; gas well venting during completions and workovers with hydraulic fracturing, and well venting for liquids unloading. API requested that for these two emission sources reporters be allowed the option to collect data in 2012 to meet the 2011 reporting requirements.

Response: EPA agrees that for the emission sources noted by the commenter; gas well venting from completions and workovers with hydraulic fracturing, and the well venting for liquids unloading emission source types, that reporters may use 2012 data collected prior to September 28, 2012 for reporting for the 2-year period—2011–2012.

Based on the provisions in the final rule for subpart W published in November 2010, reporters are to collect data every other year for use in the calculation methodologies outlined in the rule. Because of the timing in finalizing the technical corrections and technical revisions to subpart W, EPA believes that it would be appropriate for reporters to be allowed to use 2012 data collected prior to September 28, 2012 for reporting for the 2-year period 2011–2012. EPA believes that for this first two years of data collection for these emission sources that this would fall within the procedures for estimating missing data in 40 CFR 98.235. In

addition, as previously mentioned, the measurement taken for the 2011–2012 data collection requirement must be taken in sufficient time to be reported by the September 28, 2011 reporting deadline for facilities reporting for onshore production. Where applicable, EPA asserts that reporters may use the procedures available in 40 CFR 98.235 for estimating missing data.

8. Blowdown Vent Stacks: Emergency Blowdown

Comment: Commenters noted ambiguity with the proposed revisions to account for emergency blowdowns and requested that EPA clarify that emergency events are excluded from blowdown vent stack emissions reporting. Commenters further suggested that EPA delete reporting of emissions from emergency blowdowns.

Response: EPA's intent is not to cover the blowdowns that are automatically monitored by a computer system which performs numerous actions for accident protection. EPA's intent is to cover those blowdown events that require *human or manned* intervention. To clarify this intent, Section 98.233(i) has been amended to clarify that blowdown vent emissions must include blowdowns from depressurizing equipment to reduce system pressure for planned or emergency shutdowns resulting from *human intervention* or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting, etc.). Any equipment blowdown initiated by operator intervention (as opposed to automated controls that function in the absence of operator intervention), allows the operator to document the necessary data to determine the blowdown volume. In other words, if any instrument indicates that equipment needs to be taken out of service for any reason including what an operator might consider an emergency, and the operator actuates the automatic controls that isolate that equipment and opens the blowdown vent, then the operator can reasonably document what unique physical volume is isolated and depressurized, and what the starting and ending pressures are.

The blowdown events that are excluded include controls which cause venting in the absence of any operator presence or interaction. Examples include over-pressure relief valves, operational pressure controls, or automated emergency shutdown that includes opening vents to isolate and depressurize equipment without any human intervention.

9. Addition of Oil Formation Type in the Sub-Basin Category Definition

Comment: In September 2011, EPA proposed a definition for sub-basin category to replace the November 2010 delineation of wells within a basin according to fields. Commenters were supportive of the definition but suggested some modifications to the structure of the definition. For example, commenters pointed out that there was no formation defined for oil production. There are emission sources such as storage tanks that have to report emissions by sub-basin category. However, wells that produce oil and are not located in one of the four gas formations (shale gas, tight reservoir rock, coal seam, and conventional gas) were not represented in the September 2011 definition of the sub-basin category. Commenters requested that an oil formation type be added to the sub-basin category definition.

Response: EPA agrees with the commenters and has added oil formation type to the definition of sub-basin category in 40 CFR 98.238. Any well that produces hydrocarbon liquids and is not located in one of the four gas formations is now designated as oil formation. EPA notes that hydrocarbon liquids produced from wells in the gas formation (*i.e.* condensate) has to be accounted for in the respective gas formation and not the oil formation. The emission characteristics of hydrocarbon liquids produced in gas formations are different from hydrocarbon liquids produced in oil formations. Furthermore, EPA has removed the November 2010 definitions of oil wells and gas wells, since these were in conflict with the definition of sub-basin category. The November 2010 definitions for oil and gas wells were linked to the zones or reservoirs from which they were producing. However, the sub-basin category definition uses formation type. To keep all definitions interrelated and avoid conflicts EPA now defines a gas well as one which produces from a gas formation, and an oil well as one which produces from an oil formation in the sub-basin category definition.

10. Dehydrators Owned and Operated by Third Parties

Comment: EPA has received comments questioning the treatment of equipment such as a dehydrator located on a well-pad, but owned and operated by the gas processor, not the producer. One commenter noted that in the September 2011 proposal under § 98.230(a)(2), dehydrators are still referenced in the onshore petroleum

and natural gas production industry segment. This commenter then stated that dehydrators located on a well-pad and owned and operated by a gas processor should not report under onshore natural gas production because the gas processor is not a production owner or operator.

Response: The facility definition for onshore production in 40 CFR 98.238 is defined as all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO₂ EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin. Reporters need to evaluate their situation against that definition to make a determination regarding the applicability of a dehydrator.

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

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

B. Paperwork Reduction Act

This action finalizes amendments to reporting methodologies in subpart W and amendments to clarify monitoring methodologies and data reporting requirements. In many cases, the amendments to the reporting requirements do not increase reporting burden but rather, ensure that the reporting requirements conform more closely to current industry practices. Therefore, the amendments to the information collection requirements have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document has been assigned EPA ICR number 2376.05.

The Office of Management and Budget has previously approved the information collection requirements contained in the existing rules, 40 CFR part 98 subpart W (75 FR 74458), under the provisions of the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0651 and 2060–0650 respectively.

The OMB control numbers for EPA’s regulations in 40 CFR are listed in 40 CFR Part 9. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

C. Regulatory Flexibility Act (RFA)

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

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

After considering the economic impacts of this action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant *adverse* economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives “which minimize any significant economic impact of the rule on small entities” 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

As part of the process for finalization of the subpart W rule (75 FR 74458), EPA undertook specific steps to evaluate the effect of that final rule on small entities. Under that final rule for subpart W (75 FR 74458) EPA conducted a screening assessment comparing compliance costs to onshore

petroleum and natural gas industry specific receipts data for establishments owned by small businesses. The results of that screening analysis, as detailed in the preamble to the final rule for subpart W (75 FR 74482), demonstrated that the cost-to-sales ratios were less than one percent for establishments owned by small businesses that EPA considered most likely to be covered by the reporting program. The results of that analysis can be found in the preamble to the final rule (75 FR 74485).

Based on the final amendments in this action, EPA has increased flexibility in the selection of methods used for calculating GHG’s by providing alternative methods where appropriate, revised specific methods in the rule to clarify requirements, clarified specific provisions related to applicability to clearly state EPA’s intent, corrected technical errors in equations, and revised specific provisions to further clarify what must be reported and where measurement must be taken at a facility. These revisions do not add additional burden on reporters but maintain the data quality of the information being reported to EPA, and in many cases reduce burden. We have therefore concluded that this action will relieve regulatory burden for all affected small entities.

D. Unfunded Mandates Reform Act (UMRA)

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

These final rule amendments do not contain a Federal mandate that may result in expenditures of \$100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Thus, the final rule amendments are not subject to the requirements of section 202 and 205 of the UMRA. This action is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might

significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

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

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). During the finalization of subpart W in 2010 (75 FR 74458), EPA undertook the necessary steps to determine the impact of those rules on tribal entities and provided supporting documentation demonstrating the results of the Agency's analyses. And in several cases, the amendments to the reporting requirements would potentially reduce the reporting burden. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, EPA consulted with tribal officials during the development of the subpart W (75 FR 74458). A summary of the concerns raised during that consultation and EPA's response to those concerns is provided in Sections VIII.E and VIII.F of the preamble to the 2009 final rule and Section IV.F of the preamble to the 2010 final rule for subpart W (75 FR 74485).

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

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

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

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

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104-113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

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

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

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

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA),

generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective on December 28, 2011.

List of Subjects in 40 CFR Part 98

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

Dated: December 2, 2011.

Lisa P. Jackson,
Administrator.

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

PART 98—[AMENDED]

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

Authority: 42 U.S.C. 7401-7671q.

Subpart A—[Amended]

- 2. Section 98.1 is amended by adding paragraph (c) to read as follows:

§ 98.1 Purpose and scope.

* * * * *

(c) For facilities required to report under onshore petroleum and natural gas production under subpart W of this part, the terms *Owner* and *Operator* used in subpart A have the same definition as *Onshore petroleum and natural gas production owner or operator*, as defined in § 98.238 of this part.

- 3. Section 98.6 is amended by revising the definitions of "Continuous bleed" and "Intermittent bleed pneumatic devices" to read as follows:

§ 98.6 Definitions.

* * * * *

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the

process set-point to adjust gas pressure in the valve actuator.

* * * * *

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously.

* * * * *

Subpart W—[Amended]

■ 4. Section 98.230 is amended by revising paragraphs (a)(2) through (a)(4), and (a)(8) to read as follows:

§ 98.230 Definition of the source category.

(a) * * *

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO₂ or natural gas injection, and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO₂ separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that

fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

* * * * *

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

* * * * *

- 5. Section 98.232 is amended by:
 - a. Revising paragraph (a).
 - b. Revising paragraph (c) introductory text.
 - c. Revising paragraph (c)(22).
 - d. Revising paragraph (d) introductory text.
 - e. Revising paragraph (e) introductory text.
 - f. Revising paragraph (f) introductory text.
 - g. Revising paragraph (g) introductory text.
 - h. Revising paragraph (h) introductory text.
 - i. Revising paragraph (i).
 - j. Removing and reserving paragraph (j).
 - k. Revising paragraph (k).

The revisions read as follows:

§ 98.232 GHGs to report.

(a) You must report CO₂, CH₄, and N₂O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO₂, CH₄, and

N₂O emissions from each flare as specified in paragraph (b) through (i) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

* * * * *

(c) For an onshore petroleum and natural gas production facility, report CO₂, CH₄, and N₂O emissions from only the following source types on a single well-pad or associated with a single well-pad:

* * * * *

(22) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO₂, CH₄, and N₂O 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 production facility as defined in § 98.238. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO₂, CH₄, and N₂O emissions from the following sources:

* * * * *

(e) For onshore natural gas transmission compression, report CO₂, CH₄, and N₂O emissions from the following sources:

* * * * *

(f) For underground natural gas storage, report CO₂, CH₄, and N₂O emissions from the following sources:

* * * * *

(g) For LNG storage, report CO₂, CH₄, and N₂O emissions from the following sources:

* * * * *

(h) LNG import and export equipment, report CO₂, CH₄, and N₂O emissions from the following sources:

* * * * *

(i) For natural gas distribution, report CO₂, CH₄, and N₂O emissions from the following sources:

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

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

(3) Meters, regulators, and associated equipment at above grade metering-regulating station.

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

(5) Pipeline main equipment leaks.

(6) Service line equipment leaks.

(7) Report under subpart W of this part the emissions of CO₂, CH₄, and N₂O from stationary fuel combustion sources following the methods in § 98.233(z)

(j) [Reserved]

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production 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.

* * * * *

■ 6. Section 98.233 is amended by:

■ a. In paragraph (a), revising Equation W-1 and its definitions.

■ b. Adding paragraph (a)(3).

■ c. In paragraph (c), revising Equation W-2 and its definitions.

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

■ e. Revising the first sentence of paragraph (d)(2) and the definition “V_s” in Equation W-3.

■ f. Revising paragraph (d)(3).

■ g. Revising the first sentence of paragraph (d)(4) introductory text.

■ h. Revising paragraph (e) introductory text, (e)(1) introductory text, (e)(1)(vii), (e)(1)(xi) introductory text, (e)(1)(xi)(A) through (C), and (e)(2) introductory text.

■ i. In paragraph (e)(2), revising the definition of “EF_i”, “Count”, and “1000” in Equation W-5.

■ j. Revising the first sentence of paragraph (e)(5) introductory text.

■ k. Revising paragraph (e)(6).

■ l. Revising paragraph (f)(1) introductory text.

■ m. Revising paragraphs (f)(1)(i)(A) through (f)(1)(i)(C).

■ n. Revising paragraph (f)(2).

■ o. In paragraph (f)(3) introductory text, revising Equation W-9 and its definitions.

■ p. Removing and reserving paragraphs (f)(3)(i) and (f)(3)(ii).

■ q. Revising paragraph (g) introductory text.

■ r. Revising paragraphs (g)(1) introductory text and (g)(1)(i).

■ s. Revising paragraph (g)(1)(ii) introductory text; removing Equation W-11 and its definitions, adding Equations W-11A, W-11B, W-11C and their definitions, and revising W-12 and its definitions.

■ t. Redesignating paragraphs (g)(1)(ii)(A) through (g)(1)(ii)(C) as paragraphs (g)(1)(iii) through (g)(1)(v) and revising newly redesignated paragraphs (g)(1)(iii) through (g)(1)(v).

■ u. Removing paragraph (g)(1)(ii)(D).

■ v. Revising paragraph (g)(3).

■ w. Removing paragraph (g)(5) and redesignating paragraph (g)(6), (g)(6)(i), and (g)(6)(ii) as (g)(5), (g)(5)(i), and (g)(5)(ii).

■ x. Revising paragraph (h) introductory text.

■ y. Removing paragraph (h)(1).

■ z. Redesignating paragraphs (h)(2) and (h)(3) introductory text as paragraphs (h)(1) and (h)(2) introductory text, respectively, and revising newly redesignated paragraph (h)(1).

■ aa. Revising paragraph (i).

■ bb. Revising the first sentence of paragraph (j)(1) and revising paragraphs (j)(1)(vii) introductory text, (j)(1)(vii)(B), and (j)(1)(vii)(C).

■ cc. Revising paragraph (j)(2).

■ dd. Revising paragraph (j)(3) introductory text and paragraph (j)(3)(i).

■ ee. Revising paragraph (j)(4) introductory text.

■ ff. In paragraph (j)(5), revising Equation W-15, revising the definitions of “EF_i” and “Count”, and adding the definition of “1,000”.

■ gg. In paragraph (j)(8), revising Equation W-16, revising the definition of “En”, removing the definition of “E_t”, and adding the definition of “8,760”.

■ hh. Revising paragraphs (k) introductory text, (k)(1), (k)(2) introductory text, (k)(2)(i), and (k)(4); and adding new paragraph (k)(2)(iv).

■ ii. Revising paragraph (l)(1).

■ jj. Revising paragraph (l)(3).

■ kk. Revising paragraph (m)(1) and revising equation W-18 and its definitions in paragraph (m)(3).

■ ll. Revising paragraph (n)(2)(ii) and (n)(2)(iii), and in paragraph (n)(4),

republishing Equations W-19 and W-20 and revising Equation W-21.

■ mm. Redesignating paragraph (n)(9) as paragraph (n)(10) and adding new paragraphs (n)(9) and (n)(11).

■ nn. In paragraph (o)(6), revising the definition of “MT_m” in Equation W-24.

■ oo. In paragraph (o)(7), revising the definition of “EF_i” in Equation W-25.

■ pp. In paragraph (p)(7)(i) introductory text, revising the definition of “MT_m” in Equation W-28.

■ qq. In paragraph (p)(9), revising the definition of “EF_i” in Equation W-29.

■ rr. Revising paragraph (q) introductory text.

■ ss. Revising paragraph (q)(8).

■ tt. Revising paragraph (r) introductory text and the definitions in Equation W-31.

■ uu. Revising paragraphs (r)(2)(i)(A), (r)(6)(i), (r)(6)(ii).

■ vv. Revising introductory texts for paragraphs (t) and (t)(1), and revising the definitions of “T_s” and “P_s” in Equation W-33.

■ ww. Revising paragraph (t)(2) and the parameters “T_s” and “P_s” in Equation W-34.

■ xx. Adding paragraph (t)(3).

■ yy. Revising paragraph (u) introductory text, paragraph (u)(2).

■ zz. In paragraph (v), revising the only sentence of paragraph (v), Equation W-36, and the definitions of “Mass_{s,i}”, “E_{s,i}”, and “ρ_i” in Equation W-36.

■ aaa. In paragraph (w)(3), revising Equation W-37 and the definitions of parameters “Mass_{c,i}” and “GHG_i”.

■ bbb. In paragraph (x)(2), revising Equation W-38 and the definitions of parameter “Mass_{s,CO2}”.

■ ccc. Revising paragraph (z) introductory text,

(z)(1),(z)(2) introductory text, (z)(2)(i),(z)(2)(ii), (z)(2)(iii), and (z)(3).

■ ddd. Redesignating paragraphs (z)(4), (z)(5), and (z)(6) as (z)(2)(iv), (z)(2)(v), and (z)(2)(vi), respectively.

■ eee. In newly redesignated paragraph (z)(2)(vi), revising Equation W-40, removing the definition for N₂O, revising the definition of “HHV”, and adding the definitions “GWP” and “Mass_{s,N2O}”.

■ fff. Adding paragraph (z)(4).

The revisions read as follows:

§ 98.233 Calculating GHG emissions.

(a) * * *

$$Mass_{t,i} = Count_t * EF_t * GHG_i * Conv_i * T_i \quad (\text{Eq. W-1})$$

Where:

Mass_{t,i} = Annual total mass GHG emissions in metric tons CO₂e per year from a

natural gas pneumatic device vent of type “t”, for GHG_i.

Count_t = Total number of natural gas pneumatic devices of type “t” (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1), (a)(2), and (a)(3) of this section.
 EF_t = Population emission factors for natural gas pneumatic device venting listed in Tables W-1A, W-3, and W-4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH₄, or CO₂, in natural gas as defined in paragraph (u)(2)(i) of this section and for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH₄ and 1.1 × 10⁻² for CO₂.
 Conv_i = Conversion from standard cubic feet to metric tons CO₂e; 0.000403 for CH₄, and 0.00005262 for CO₂.
 T_i = Average estimated number of hours in the operating year the devices, of each

type t, were operational. Default is 8760 hours.
 * * * * *
 (3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.
 * * * * *
 (c) * * *

$$Mass_i = Count * EF * GHG_i * Conv_i * T \quad (\text{Eq. W-2})$$

Where:

Mass_i = Annual total mass GHG emissions in metric tons CO₂e per year from all natural gas pneumatic pump venting, for GHG_i.
 Count = Total number of natural gas pneumatic pumps.
 EF = Population emissions factors for natural gas pneumatic pump venting listed in Tables W-1A of this subpart for onshore petroleum and natural gas production.
 GHG_i = Concentration of GHG_i, CH₄, or CO₂, in produced natural gas as defined in paragraph (u)(2)(i) of this section.
 Conv_i = Conversion from standard cubic feet to metric tons CO₂e; 0.000403 for CH₄, and 0.00005262 for CO₂.
 T = Average estimated number of hours in the operating year the pumps were operational. Default is 8760 hours.

(d) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other adsorbents and adsorbents), calculate emissions for CO₂ only (not CH₄) vented directly to the atmosphere or through a flare, engine (e.g., permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as

fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section, as applicable.
 (1) *Calculation Methodology 1.* If you operate and maintain a CEMS that has both a CO₂ concentration monitor and volumetric flow rate monitor, you must calculate CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer’s instructions or industry standard practice. If a CO₂ concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO₂ concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion). The calculation and reporting of CH₄

and N₂O emissions is not required as part of the Tier 4 requirements for AGRs.
 (2) *Calculation Methodology 2.* If CEMS is not available but a vent meter is installed, use the CO₂ composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.
 * * * * *
 V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer’s instructions or industry standard practice for calibration of the vent meter.
 * * * * *
 (3) *Calculation Methodology 3.* If CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO₂ using Equations W-4A or W-4B of this section. If inlet gas flow rate is known, use Equation W-4A. If outlet gas flow rate is known, use Equation W-4B.

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

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

Where:

E_{a, CO2} = Annual volumetric CO₂ emissions at actual conditions, in cubic feet per year.
 V_{in} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.
 V_{out} = Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual condition as

determined using methods specified in paragraph (d)(5) of this section.
 Vol_I = Volume fraction of CO₂ content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.
 Vol_O = Volume fraction of CO₂ content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.
 (4) *Calculation Methodology 4.* If CEMS or a vent meter is not installed,

you may calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO₂ emissions.* * *
 * * * * *
 (e) *Dehydrator vents.* For dehydrator vents, calculate annual CH₄, CO₂ and N₂O emissions using any of the

calculation methodologies described in paragraph (e) of this section.

(1) *Calculation Methodology 1.* Calculate annual mass emissions from dehydrator vents with annual average daily throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI-GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH₄ and CO₂ emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

* * * * *
(vii) Use of stripping gas.
* * * * *

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(1)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) or (u)(2)(ii) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) or (u)(2)(ii) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in § 98.234(b) to sample and analyze wet natural gas composition.
* * * * *

(2) *Calculation Methodology 2.* Calculate annual CH₄ and CO₂ emissions from glycol dehydrators with annual average daily throughput less than 0.4 million standard cubic feet per day using Equation W-5 of this section:
* * * * *

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

Where:

E_{s,n} = Annual natural gas emissions at standard conditions, in cubic feet/year.
W = Total number of wells with well venting for liquids unloading for each sub-basin.
0.37×10⁻³ = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
CD_p = Casing internal diameter for each well, p, in inches.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH₄ and 3.21 for CO₂ at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million standard cubic feet per day.

1000 = Conversion of EF_i in thousand standard cubic feet to standard cubic feet.

* * * * *

(5) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W-6 of this section. * * *

(6) For glycol dehydrators, both CH₄ and CO₂ mass emissions shall be calculated from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For dehydrators that use desiccant, both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.
(f) * * *

(1) *Calculation Methodology 1.* For one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see § 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g., on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate emissions from well venting for liquids unloading using Equation W-7 of this section.

$$E_{a,n} = \sum_{p=1}^h T_p FR_p \quad (\text{Eq. W-7})$$

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.
SP_p = Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia) or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well, p,

Where:

E_{a,n} = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions in cubic feet.

h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin.

p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.

T_p = Cumulative amount of time in hours of venting from the measured well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year.

FR_p = Average flow rate in cubic feet per hour of a measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) * * *

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total flow by the recorded time (in hours) for a single liquid unloading with venting to the atmosphere.

(B) This average flow rate per hour is applied to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting sub-basin category starting the first calendar year of data collection. For a new producing sub-basin category, an average flow rate is calculated beginning in the first year of production.
* * * * *

(2) *Calculation Methodology 2.* Calculate the total emissions for well venting for liquids unloading using Equation W-8 of this section.

in the sub-basin, in pounds per square inch absolute (psia).

V_p = Number of vents per year per well, p.
SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 to calculate the average flow-line rate at standard conditions.

HR_{p,q} = Hours that each well, p, was left open to the atmosphere during unloading, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(3) * * *

$$E_{s,n} = \sum_{p=1}^W \left[V_p \times \left((0.37 \times 10^{-3}) \times TD_p^2 \times WD_p \times SP_p \right) + \sum_{q=1}^{V_p} \left(SFR_q \times (HR_{p,q} - 0.5) \times Z_{p,q} \right) \right] \quad (\text{Eq. W-9})$$

Where:

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

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

$0.37 \times 10^{-3} = \{3.14 (\pi) / 4\} / \{14.7 * 144\}$ (psia converted to pounds per square feet).

TD_p = Tubing internal diameter for each well, p, in inches.

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

SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

V_p = Number of vents per year for each well, p.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

(i) [Reserved]

(ii) [Reserved]

(g) *Gas well venting during completions and workovers from hydraulic fracturing.* Calculate CH_4 , CO_2 and N_2O annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W-10A or Equation W-10B of this section. Equation W-10A applies to well venting when the backflow rate is measured or

calculated, Equation W-10B applies when the backflow vent or flare volume is measured. Use Equation W-10A if the flow rate for backflow during well completions and workovers from hydraulic fracturing is known for the specified number of wells per paragraph (g)(1) in a sub-basin and well type (horizontal or vertical) combination. Use Equation W-10B if the flow volume for backflow during well completions and workovers from hydraulic fracturing is known for all wells in a sub-basin and well type (horizontal or vertical) combination. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{s,n} = \sum_{p=1}^W \left[T_p \times FRM \times PR_p - EnF_p - SG_p \right] \quad (\text{Eq. W-10A})$$

$$E_{s,n} = \sum_{p=1}^W \left[FV_p - EnF_p \right] \quad (\text{Eq. W-10B})$$

Where:

$E_{s,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions or workovers following hydraulic fracturing for each sub-basin and well type (horizontal vs. vertical) combination.

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

T_p = Cumulative amount of time of backflow for the completion or workover, in hours, for each well, p, in a sub-basin and well type (horizontal vs. vertical) combination during the reporting year.

FRM = Ratio of backflow during well completions and workovers from hydraulic fracturing to 30-day production rate from Equation W-12.

PR_p = First 30-day average production flow rate in standard cubic feet per hour of each well p, under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.

EnF_p = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job for each well p. If the fracture process did not inject gas

into the reservoir, then EnF_p is 0. If injected gas is CO_2 , then EnF_p is 0.

SG_p = Volume of natural gas in cubic feet at standard conditions that was recovered into a flow-line for well p as per paragraph (g)(3) of this section. This parameter includes any natural gas that is injected into the well for clean-up. If no gas was recovered, SG_p is 0.

FV_p = Flow volume 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 backflow during the completion or workover according to methods set forth in § 98.234(b).

(1) The average flow rate for backflow during well completions and workovers from hydraulic fracturing shall be determined using measurement(s) for calculation methodology 1 or calculation(s) for calculation methodology 2 described in this paragraph (g)(1) of this section. If Equation W-10A is used, the number of measurements or calculations shall be determined per sub-basin and well type (horizontal or vertical) as follows: one measurement or calculation for less than

or equal to 25 completions or workovers; two measurements or calculations for 26 to 50 completions or workovers; three measurements or calculations for 51 to 100 completions or workovers; four measurements or calculations for 101 to 250 completions or workovers; and five measurements or calculations for greater than 250 completions or workovers.

(i) *Calculation Methodology 1.* When using Equation W-10A, for each measured well completion(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination and for each measured well workover(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare or vent if used, to measure the backflow rate according to methods set forth in § 98.234(b).

(ii) *Calculation Methodology 2.* When using Equation W-10A, for each calculated horizontal well completion

and each calculated vertical well completion in each gas producing sub-basin category and for each calculated well horizontal workover and for each calculated vertical well workover in each gas producing sub-basin category, record the well flowing pressure upstream (and downstream in subsonic

flow) of a well choke according to methods set forth in § 98.234(b) to calculate the well backflow during well completions and workovers from hydraulic fracturing. Calculate emissions using Equation W-11A of this section for subsonic flow or Equation W-11B of this section for sonic flow.

Use best engineering estimate based on best available data along with Equation W-11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W-11C is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic:

$$FR = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1} \right)^{1.515} - \left(\frac{P_2}{P_1} \right)^{1.758} \right]} \quad (\text{Eq. W-11A})$$

Where:

FR = Average flow rate in cubic feet per hour, under subsonic flow conditions.

A = Cross sectional area of orifice (m²).
 P₁ = Upstream pressure (psia).
 T_u = Upstream temperature (degrees Kelvin).
 P₂ = Downstream pressure (psia).

3430 = Constant with units of m²/(sec² * K).
 1.27*10⁵ = Conversion from m³/second to ft³/hour.

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

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.

A = Cross sectional area of orifice (m²).
 T_u = Upstream temperature (degrees Kelvin).
 187.08 = Constant with units of m²/(sec² * K).
 1.27*10⁵ = Conversion from m³/second to ft³/hour.

$$R = \frac{P_1}{P_2} \quad (\text{Eq. W-11C})$$

Where:
 R = Pressure ratio
 P₁ = Pressure upstream of the restriction orifice in pounds per square inch absolute.

P₂ = Pressure downstream of the restriction orifice in pounds per square inch absolute.

(iii) For Equation W-10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate is calculated using Equation W-12 of this section.

$$FRM = \frac{\sum_{p=1}^W FR_p}{\sum_{p=1}^W PR_p} \quad (\text{Eq. W-12})$$

Where:

FRM = Ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate.
 FR_p = Measured backflow rate from Calculation Methodology 1 or calculated flow rate from Calculation Methodology 2 in standard cubic feet per hour for well(s) p for each sub-basin and well type (horizontal or vertical) combination. You may not use flow volume as used in Equation W-10B converted to a flow rate for this parameter.
 PR_p = First 30-day production rate in standard cubic feet per hour for each well p that was measured in the sub-basin and well type combination.
 W = Number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type formation.

to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well workovers, respectively, in the gas producing sub-basin and well type combination for the total number of hours of backflow for each of these wells.

(v) For Equation W-10A, new flow rates for horizontal and vertical gas well completions and horizontal and vertical gas well workovers in each sub-basin category shall be calculated once every two years starting in the first calendar year of data collection.

* * * * *

(3) Determine if the backflow gas from the well completion or workover from hydraulic fracturing is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line

(e.g., reduced emissions completion or workovers).

(i) Use the factor SG_p in Equation W-10A of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the backflow as determined by engineering estimate based on best available data.

(ii) [Reserved]

(iii) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

* * * * *

(h) Gas well venting during completions and workovers without hydraulic fracturing. Calculate CH₄, CO₂ and N₂O emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing using Equation W-13 of this section:

(iv) For Equation W-10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate for horizontal and vertical wells are applied

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

Where:

$E_{s,n}$ = Annual natural gas emissions in standard cubic feet from a gas well venting during well completions and workovers without hydraulic fracturing.
 N_{wo} = Number of workovers per sub-basin category that flare gas or vent gas to the atmosphere and do not involve hydraulic fracturing in the reporting year.
 EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. EF_{wo} = 3114 standard cubic feet natural gas per well workover without hydraulic fracturing.
 p = Well completions 1 through f in a sub-basin.
 f = Total number of well completions without hydraulic fracturing in a sub-basin category.
 V_p = Average daily gas production rate in standard cubic feet per hour for each well completion without hydraulic fracturing, p . This is the total annual gas production volume divided by total number of hours the wells produced to the flow-line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the

event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.
 T_p = Time each well completion without hydraulic fracturing, p , was venting in hours during the year.

(1) Volumetric emissions for both CH₄ and CO₂ shall be calculated from volumetric natural gas emissions using calculations in paragraph (u) of this section. Mass emissions for both CH₄ and CO₂ shall be calculated from volumetric natural gas emissions using calculations in paragraphs (v) of this section.

* * * * *
 (i) *Blowdown vent stacks.* Calculate CO₂ and CH₄ blowdown vent stack emissions from depressurizing equipment(s) to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating

pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

- (1) Calculate the unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimates based on best available data.
- (2) If the unique physical volume between isolation valves is greater than or equal to 50 cubic feet, retain logs of the number of blowdowns for each unique physical volume (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Unique physical volumes smaller than 50 cubic feet are exempt from reporting under paragraph (i) of this section.
- (3) Calculate the total annual venting emissions for unique volumes using either Equation W-14A or W-14B of this section.

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

Where:

$E_{S,N}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
 N = Number of occurrences of blowdowns for each unique physical volume in calendar year.

V = Unique physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet.
 C = Purge factor that is 1 if the unique physical volume is not purged or zero if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60°F).
 T_a = Temperature at actual conditions in the unique physical volume (°F).
 P_s = Absolute pressure at standard conditions (14.7 psia).
 P_a = Absolute pressure at actual conditions in the unique physical volume (psia).

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

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
 p = Individual occurrence of blowdown for the same unique physical volume.
 N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.
 V = Total physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown “ p .”
 T_s = Temperature at standard conditions (60°F).

T_a = Temperature at actual conditions in the unique physical volume (°F) for each blowdown “ p .”
 P_s = Absolute pressure at standard conditions (14.7 psia).
 $P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown “ p .”
 $P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown “ p ”; 0 if blowdown volume is purged using non-GHG gases.

calculations in paragraph (u) and (v) of this section.

- (j) * * *
- (1) *Calculation Methodology 1.* For separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. * * *
- * * * * *
- (vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods

(4) Calculate both CH₄ and CO₂ volumetric and mass emissions using

described under paragraph (j)(1) (vii) of this section.

* * * * *

(B) If separator 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.

(C) Analyze a representative sample of separator oil in each sub-basin category for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2.*

Calculate annual CH₄ and CO₂ emissions from onshore production storage tanks for wellhead gas-liquid separators with annual average daily throughput of oil greater than or equal

to 10 barrels per day by assuming that all of the CH₄ and CO₂ 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.

(3) *Calculation Methodology 3.* For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate annual CH₄ and CO₂ emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH₄ and CO₂ in both oil and gas are emitted from the tank.

* * * * *

(4) *Calculation Methodology 4.* For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate annual CH₄ and CO₂ emissions by either of the methods in paragraph (j)(4) of this section:

* * * * *

(5) * * *

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

Where:

* * * * *

EF_i = Population emission factor for separators or wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.2 for CH₄ and 2.8 for

CO₂ at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH₄ and 2.8 for CO₂ at 60 °F and 14.7 psia.

Count = Total number of separators or wells with throughput less than 10 barrels per day.

1,000 = Conversion to cubic feet

* * * * *

(8) * * *

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

Where:

* * * * *

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 4 in paragraphs (j)(1), (j)(2) and (j)(4) of this section (with wellhead separators) in standard cubic feet per year.

* * * * *

8,760 = Conversion to hourly emissions.

* * * * *

(k) *Transmission storage tanks.* For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, calculate CH₄, CO₂ and N₂O annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) or by directly measuring the tank vent using a flow meter or high volume sampler according to methods in § 98.234(b) through (d) for a duration of 5 minutes, or a calibrated bag according to methods

in § 98.234(b). Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify annual emissions:

(i) Use a meter, such as a turbine meter, calibrated bag, or high flow sampler to estimate tank vapor volumes from the vent stack according to methods set forth in § 98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph § 98.233(k)(1) of this section to detect continuous leakage, this serves as the measurement.

* * * * *

(iv) Calculate GHG volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

* * * * *

(4) Calculate annual emissions from storage tanks to flares as follows:

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

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

(1) * * *

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from oil well(s) tested. Determine the production rate from gas well(s) tested.

* * * * *

(3) Estimate venting emissions using Equation W-17A or Equation W-17B of this section.

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

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

Where:

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

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

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

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

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

* * * * *

(m) * * *

(1) Determine the GOR of the hydrocarbon production from each well

whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same sub-basin category shall be used.

* * * * *

(3) * * *

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

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting under actual conditions, in cubic feet.

GOR_{p,q} = Gas to oil ratio, for well p in sub-basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V_{p,q} = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year during which associated gas was vented or flared.

x = Total number of wells in sub-basin that vent or flare associated gas.

y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

* * * * *

(n) * * *

(2) * * *

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG

mole percent in feed natural gas liquid for all streams.

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

* * * * *

(4) * * *

$$E_{a,CH4}(un - combusted) = V_a * (1 - \eta) * X_{CH4} \quad (\text{Eq. W-19})$$

$$E_{a,CO2}(un - combusted) = V_a * X_{CO2} \quad (\text{Eq. W-20})$$

$$E_{a,CO2}(combusted) = \sum_{j=1}^5 (\eta * V_a * Y_j * R_j) \quad (\text{Eq. W-21})$$

* * * * *

(9) If you operate and maintain a CEMS that has both a CO₂ concentration monitor and volumetric flow rate monitor, you must calculate only CO₂ emissions for the flare. You must follow the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (n)(1) through (n)(7) are not required. If

a CO₂ concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO₂ concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(11) If source types in § 98.233 use Equations W-19 through W-21 of this section, use estimate of emissions under actual conditions for the parameter, V_a, in these equations.

(o) * * *

(6) * * *

MT_m = Flow Measurements from all centrifugal compressor vents in each mode in (o)(1)(i) through (o)(1)(iii) of this section in standard cubic feet per hour.

* * * * *

(7) * * *

EF_i = Emission factor for GHG_i. Use 1.2 × 10⁷ standard cubic feet per year per compressor for CH₄ and 5.30 × 10⁵ thousand standard cubic feet per year per compressor for CO₂ at 60 °F and 14.7 psia.

* * * * *

(p) * * *
 (7) * * *
 (i) * * *

MT_m = Meter readings from all reciprocating compressor vents in each and mode, m, in standard cubic feet per hour.

* * * * *

(9) * * *

EF_i = Emission factor for GHG_i. Use 9.48 × 10³ standard cubic feet per year per compressor for CH₄ and 5.27 × 10² standard cubic feet per year per compressor for CO₂ at 60 °F and 14.7 psia.

* * * * *

(q) *Leak detection and leaker emission factors.* You must use the methods described in § 98.234(a) to conduct leak detection(s) of equipment leaks from all component types listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to component types in streams with gas content greater than 10 percent CH₄ plus CO₂ by weight. Component types in streams with gas content less than 10 percent CH₄ plus CO₂ by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the

requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate equipment leak emissions per component type per reporting facility using Equations W-30A or W-30B of this section for each component type. Use Equation W-30A for industry segments listed in 98.230(a)(3)–(a)(7). Use Equation W-30B for industry segments listed in 98.230(a)(8).

$$E_{s,i} = GHG_i * \sum_{p=1}^x (EF * T_p) \tag{Eq. W-30A}$$

$$E_{s,i} = GHG_i * \sum_{q=t-n+1}^t \sum_{p=1}^x (EF * T_{p,q}) \tag{Eq. W-30B}$$

Where:

E_{s,i} = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (q)(1) through (q)(8) of this section.

x = Total number of each component type.

EF = Leaker emission factor for specific component types listed in Table W-2 through Table W-7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH₄ or CO₂, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH₄ and 1.1 × 10⁻² for CO₂; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH₄ and 0 for CO₂; and for natural gas distribution, GHG_i equals 1 for CH₄ and 1.1 × 10⁻² CO₂.

T_p = The total time the component, p, was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

t = Calendar year of reporting.

n = The number of years over which one complete cycle of leak detection is conducted over all the T-D transfer stations in a natural gas distribution facility; 0 < n ≤ 5. For the first (n-1) calendar years of reporting the summation in Equation W-30B should be for years that the data is available.

T_{p,q} = The total time the component, p, was found leaking and operational, in hours, in year q. If one leak detection survey is conducted, assume the component was leaking for the entire period n. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found to be leaking in the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the cycle, assume that all leaking components continue to leak until the end of the cycle.

* * * * *

(8) Natural gas distribution facilities for above grade transmission-distribution transfer stations, shall use the appropriate default leaker emission factors listed in Table W-7 of this subpart for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(i) Natural gas distribution facilities may choose to conduct leak detection at the T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility chooses to use the multiple year option then the number of T-D transfer

stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(ii) [Reserved]

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH₄ plus CO₂ by weight. Emissions sources in streams with gas content less than 10 percent CH₄ plus CO₂ by weight 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. Calculate emissions from all sources listed in this paragraph using Equation W-31 of this section.

* * * * *

E_{s,i} = Annual volumetric GHG emissions at standard conditions from each component type in cubic feet.

Count_s = Total number of this type of emission source at the facility. For onshore petroleum and natural gas production, average component counts are provided by major equipment piece in Tables W-1B and Table W-1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W-1D of this subpart. Underground natural gas storage shall count the components listed for population emission factors in Table W-4. LNG Storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the

meter/regulator runs as described in paragraph (r)(6) of this section.
 EF = Population emission factor for the specific component type, as listed in Table W-1A and Tables W-3 through Table 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 for meter/regulator runs at above grade metering-regulating stations is determined in Equation W-32 of this section.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH₄ or CO₂, 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 CH₄ and 1.1 × 10⁻² for CO₂; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH₄ and 0 for CO₂; and for natural gas distribution, GHG_i equals 1 for CH₄ and 1.1 × 10⁻² CO₂.

T_s = Average estimated time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

* * * * *

- (2) * * *
- (i) * * *

(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.

* * * * *

- (6) * * *

(i) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table W-7 of this subpart. Below grade T-D transfer stations shall use the emission factor for below grade metering-regulating stations.

(ii) Emissions from all above grade metering-regulating stations (including above grade TD transfer stations) shall be calculated by applying the emission factor calculated in Equation W-32 and the total count of meter/regulator runs at all above grade metering-regulating stations (inclusive of TD transfer stations) to Equation W-31. The facility wide emission factor in Equation W-32 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation W-30B in paragraph (q)(8) of this section and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per (q)(8)(i) of this section. A meter on a regulator run

is considered one meter or regulator run. Reporters that do not have above grade T-D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with § 98.236(c)(16)(xix).

$$EF = \frac{E_{s,i} \div 8760}{Count} \quad (\text{Eq. W-32})$$

Where:

EF = Facility emission factor for a meter/regulator run per component type at above grade metering-regulating for GHG_i in cubic feet per meter/regulator run per hour.

E_{s,i} = Annual volumetric GHG i emissions, CO₂ or CH₄ at standard condition from each component type at all above grade TD transfer stations, from Equation W-30B.

Count = Total number of meter/regulator runs at all TD transfer stations that were monitored over the years that constitute one complete cycle as per (q)(8)(i) of this section.

8760 = Conversion to hourly emissions

* * * * *

(t) *Volumetric emissions.* Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation W-33 of this section.

* * * * *

T_s = Temperature at standard conditions (60 °F).

* * * * *

P_s = Absolute pressure at standard conditions (14.7 psia).

* * * * *

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W-34 of this section.

* * * * *

T_s = Temperature at standard conditions (60 °F).

* * * * *

P_s = Absolute pressure at standard conditions (14.7 psia).

* * * * *

(3) Reporters using 68 °F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68 °F to 60 °F.

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section, with mole fraction of GHGs in the natural gas determined by engineering

estimate based on best available data unless otherwise specified.

* * * * *

(2) For Equation W-35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

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

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(iv) GHG mole fraction in natural gas stored in the underground natural gas storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) GHG mole fraction in natural gas stored in the LNG storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vi) GHG mole fraction in natural gas stored in the LNG import and export industry segment. For export facilities that receive gas from transmission

pipelines, you may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vii) GHG mole fraction in local distribution pipeline natural gas that

passes through the facility for natural gas distribution facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) *GHG mass emissions*. Calculate GHG mass emissions in carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W-36 of this section.

$$Mass_i = E_{s,i} * \rho_i * GWP * 10^{-3} \quad (\text{Eq. W-36})$$

Where:

Mass_i = GHG_i (either CH₄, CO₂, or N₂O) mass emissions in metric tons CO₂e.

E_{s,i} = GHG_i (either CH₄, CO₂, or N₂O) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG_i. Use 0.0526 kg/ft³ for CO₂ and N₂O, and 0.0422 kg/ft³ for CH₄ at 60 °F and 14.7 psia.

(3) * * *

$$Mass_{CO_2} = N * V_v * R_c * GHG_{CO_2} * 10^{-3} \quad (\text{Eq. W-37})$$

Where:

Mass_{CO₂} = Annual EOR injection gas venting emissions in metric tons from blowdowns.

* * * * *

GHG_{CO₂} = Mass fraction of CO₂ in critical phase injection gas.

(x) * * *
(2) * * *

$$Mass_{CO_2} = S_{h1} * V_{h1} \quad (\text{Eq. W-38})$$

Where:

Mass_{CO₂} = Annual CO₂ emissions from CO₂ retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

* * * * *

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions*.

Calculate CO₂, CH₄, and N₂O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (z)(3) and (z)(4) of this section, as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of subpart C of this part, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to (z)(1)(i). If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation methodology described in (z)(1)(i) and you may use the emission factor provided for natural gas as listed in Table C-1. If the fuel is natural gas, and is not pipeline quality or has a high heat

value of less than 950 Btu per standard cubic feet, calculate emissions according to (z)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to (z)(2).

(i) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1, calculate CO₂, CH₄, and N₂O emissions according to any Tier listed in subpart C of this part. You must follow all applicable calculation requirements for that tier listed in 98.33, any monitoring or QA/QC requirements listed for that tier in 98.34, any missing data procedures specified in 98.35, and any recordkeeping requirements specified in 98.37.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore natural gas and petroleum production facilities and at natural gas distribution facilities will be reported according to the requirements specified in 98.236(c)(19) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a

blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet, calculate combustion emissions as follows:

(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in the applicable paragraph in (u)(2) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W-39A and W-39B of this section:

$$E_{a,CO_2} = (V_a * Y_{CO_2}) + \eta * \sum_{j=1}^5 V_a * Y_j * R_j \quad (\text{Eq. W-39A})$$

$$E_{a,CH_4} = V_a * (1 - \eta) * Y_{CH_4} \quad (\text{Eq. W-39B})$$

Where:

- E_{CO2} = Contribution of annual CO₂ emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
- V_a = Volume of gas sent to combustion unit in cubic feet, during the year.
- Y_{CO2} = Concentration of CO₂ constituent in gas sent to combustion unit.
- E_{a,CH4} = Contribution of annual CH₄ emissions from portable or stationary

- fuel combustion sources in cubic feet, under actual conditions.
- η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.
- Y_j = Concentration of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to combustion unit.

- R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.
- Y_{CH4} = Concentration of methane constituent in gas sent to combustion unit.

(vi) Calculate N₂O mass emissions using Equation W-40 of this section.

$$Mass_{N_2O} = (1 \times 10^{-3}) \times Fuel \times HHV \times EF \times GWP \quad (\text{Eq. W-40})$$

Where:

Mass_{N2O} = Annual N₂O emissions from the combustion of a particular type of fuel (metric tons CO₂e).

* * * * *

HHV = For the high heat value for field gas or process vent gas, use 1.235 × 10⁻³ mmBtu/scf for HHV.

* * * * *

GWP = Global warming potential, as listed in Table A-1 of subpart A of this part.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each internal fuel combustion unit.

- 7. Section 98.234 is amended by:
- a. Revising paragraphs (a)(1), (a)(2), and (a)(5).
- b. Removing and reserving paragraph (a)(4).
- c. Revising paragraph (c) introductory text and paragraph (d)(3).
- d. Revising Equation W-41 of paragraph (e).
- e. Adding new paragraph (g).

§ 98.234 Monitoring and QA/QC requirements.

* * * * *

(a) * * *

(1) *Optical gas imaging instrument.*

Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18 of the *Alternative work*

practice for monitoring equipment leaks, § 60.18(i)(1)(i); § 60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: *Detection Sensitivity Levels*; § 60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and § 60.18(i)(2)(iv) and (v); § 60.18(i)(3); § 60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A-7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A-7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

* * * * *

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to

detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured.

* * * * *

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

* * * * *

(d) * * *

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t). Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

* * * * *

(e) * * *

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \quad (\text{Eq. W-41})$$

Where:

p = Absolute pressure.
R = Universal gas constant.

T = Absolute temperature.

V_m = Molar volume.

$$a = \frac{0.45724R^2T_c^2}{P_c}$$

$$b = \frac{0.7780RT_c}{P_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2 \right) \left(1 - \sqrt{\frac{T}{T_c}} \right) \right)^2$$

Where:

ω = Acentric factor of the species.

T_c = Critical temperature.

P_c = Critical pressure.

* * * * *

(g) For the purposes of fulfilling requirements in 40 CFR 98.233(f) and (g) which require measurements to be taken every other year beginning in the first year of data collection, reporters have the option of taking the first measurement in 2012 to satisfy the requirements for the 2011–2012 data collection cycle.

■ 8. Section 98.236 is amended by:

■ a. Revising paragraphs (a) introductory text and (a)(8).

■ b. Revising paragraph (b).

■ c. Revising paragraphs (c) introductory text, (c)(1)(iv), (c)(2)(ii), and (c)(3)(ii) through (c)(3)(v); and adding paragraphs (c)(3)(vi) and (vii).

■ d. Revising paragraphs (c)(4)(i)(H) and (C)(4)(i)(J); and adding paragraphs (c)(4)(i)(K), and (c)(4)(i)(L).

■ e. Revising paragraphs (c)(4)(ii)(B) and (c)(4)(ii)(C); and adding paragraph (c)(4)(ii)(D).

■ f. Revising paragraph (c)(4)(iii)(B).

■ g. Revising paragraph (c)(5).

■ h. Revising paragraphs (c)(6) introductory text, and (c)(6)(i).

■ i. Revising paragraph (c)(6)(ii)(B), (c)(6)(ii)(D) and adding paragraph (c)(6)(ii)(E).

■ j. Revising paragraph (c)(7).

■ k. Revising paragraphs (c)(8)(i) introductory text and (c)(8)(i)(J); and adding paragraphs (c)(8)(i)(K) and (c)(8)(i)(L).

■ l. Revising paragraphs (c)(8)(ii) introductory text, (c)(8)(ii)(D), and (c)(8)(ii)(G); and adding paragraphs (c)(8)(ii)(H) and (c)(8)(ii)(I).

■ m. Revising paragraphs (c)(8)(iii) introductory text and (c)(8)(iii)(F); and adding paragraphs (c)(8)(iii)(G) and (c)(8)(iii)(H).

■ n. Adding paragraph (c)(8)(iv)(B).

■ o. Revising paragraphs (c)(9) introductory text and (c)(9)(i); and adding paragraphs (c)(9)(ii) (c)(9)(iii).

■ p. Revising paragraphs (c)(10) introductory text and (c)(10)(iv); and adding paragraph (c)(10)(v).

■ q. Revising paragraph (c)(11) introductory text and (c)(11)(iii); and adding paragraph (c)(11)(iv).

■ r. Revising paragraph (c)(12)(vi) and adding paragraphs (c)(12)(vii) through (c)(12)(xi).

■ s. Revising paragraphs (c)(15) introductory text, (c)(15)(i)(A), (c)(15)(i)(B) and (c)(15)(i)(C).

■ t. Revising paragraphs (c)(15)(ii)(A) through (c)(15)(ii)(C).

■ u. Revising paragraph (c)(16).

■ v. Revising paragraph (c)(17)(v).

■ w. Revising paragraphs (c)(18) introductory text and paragraph (c)(18)(iii).

■ x. Revising paragraphs (c)(19)(iii), (c)(19)(v), (c)(19)(vi), and (c)(19)(vii).

■ y. Adding paragraph (e).

The revisions read as follows:

§ 98.236 Data Reporting Requirements.

* * * * *

(a) Report annual emissions in metric tons of CO₂e for each GHG separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section.

* * * * *

(8) Natural gas distribution.

(b) For offshore petroleum and natural gas production, report emissions of CH₄,

CO₂, and N₂O as applicable to the source type (in metric tons CO₂e per year at standard conditions) individually for all of the emissions source types listed in the most recent BOEMRE study.

(c) Report the information listed in this paragraph for each applicable source type in metric tons of CO₂e for each GHG. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring the gas. Both the vented and flared emissions will be reported under the respective source type and not under the flare source type.

(1) * * *

(iv) Report annual CO₂ and CH₄ emissions at the facility level, expressed in metric tons CO₂e for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices.

(2) * * *

(ii) Report annual CO₂ and CH₄ emissions at the facility level, expressed in metric tons CO₂e for each gas, for all natural gas driven pneumatic pumps combined.

(3) * * *

(ii) For Calculation Methodology 1 and Calculation Methodology 2 of § 98.233(d), annual average fraction of CO₂ content in the vent from the acid gas removal unit (refer to § 98.233(d)(6)).

(iii) For Calculation Methodology 3 of § 98.233(d), annual average volume fraction of CO₂ content of natural gas into and out of the acid gas removal unit (refer to § 98.233(d)(7) and (d)(8)).

(iv) Report the annual quantity of CO₂, expressed in metric tons CO_{2e}, that was recovered from the AGR unit and transferred outside the facility, under subpart PP of this part.

(v) Report annual CO₂ emissions for the AGR unit, expressed in metric tons CO_{2e}.

(vi) For the onshore natural gas processing industry segment only, report a unique name or ID number for the AGR unit.

(vii) An indication of which calculation methodology was used for the AGR.

(4) * * *

(j) * * *

(H) Concentration of CH₄ and CO₂ in wet natural gas.

* * * * *

(J) For each glycol dehydrator, report annual CO₂ and CH₄ emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_{2e} for each gas.

(K) For each glycol dehydrator, report annual CO₂, CH₄, and N₂O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons CO_{2e} for each gas.

(L) For the onshore natural gas processing industry segment only, report a unique name or ID number for glycol dehydrator.

(ii) * * *

(B) Which vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)).

(C) Report annual CO₂ and CH₄ emissions at the facility level that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_{2e} for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd.

(D) Report annual CO₂, CH₄, and N₂O emissions at the facility level that resulted from the flaring of process gas, expressed in metric tons CO_{2e} for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd.

(iii) * * *

(B) Report annual CO₂ and CH₄ emissions at the facility level, expressed in metric tons CO_{2e} for each gas, for all absorbent desiccant dehydrators combined.

(5) For well venting for liquids unloading, report the following:

(i) For Calculation Methodology 1 (refer to Equation W-7 of § 98.233), report the following for each tubing

diameter group and pressure group combination within each sub-basin category:

(A) Count of wells vented to the atmosphere for liquids unloading.

(B) Count of plunger lifts. Whether the selected well from the tubing diameter and pressure group combination had a plunger lift (yes/no).

(C) Cumulative number of unloadings vented to the atmosphere.

(D) Average flow rate of the measured well venting in cubic feet per hour (refer to § 98.233(f)(1)(i)(A)).

(E) Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet, selected to represent emissions in that tubing size and pressure combination.

(F) Casing pressure, in psia, of each well selected to represent emissions in that tubing size group and pressure group combination that does not have a plunger lift.

(G) Tubing pressure, in psia, of each well selected to represent emissions in a tubing size group and pressure group combination that has a plunger lift.

(H) Report annual CO₂ and CH₄ emissions, expressed in metric tons CO_{2e} for each gas.

(ii) For Calculation Methodologies 2 and 3 (refer to Equation W-8 and W-9 of § 98.233), report the following for each sub-basin category:

(A) Count of wells vented to the atmosphere for liquids unloading.

(B) Count of plunger lifts.

(C) Cumulative number of unloadings vented to the atmosphere.

(D) Average internal casing diameter, in inches, of each well, where applicable.

(E) Report annual CO₂ and CH₄ emissions, expressed in metric tons CO_{2e} for each GHG gas.

(6) For well completions and workovers, report the following for each sub-basin category:

(i) For gas well completions and workovers with hydraulic fracturing by sub-basin and well type (horizontal or vertical) combination (refer to Equation W-10A and W-10B of § 98.233), report the following:

(A) Total count of completions in calendar year.

(B) When using Equation W-10A, measured flow rate of backflow during well completion in standard cubic feet per hour.

(C) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere.

(D) When using Equation W-10A, measured flow rate of backflow during well workover in standard cubic feet per hour.

(E) When using Equation W-10A, total number of days of backflow from all wells during completions.

(F) When using Equation W-10A, total number of days of backflow from all wells during workovers.

(G) Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available.

(H) Report number of workovers employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.

(I) Annual CO₂ and CH₄ emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_{2e} for each gas.

(J) Annual CO₂, CH₄, and N₂O emissions that resulted from flares, expressed in metric tons CO_{2e} for each gas.

(ii) * * *

(B) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere.

* * * * *

(D) Annual CO₂ and CH₄ emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_{2e} for each gas.

(E) Annual CO₂, CH₄, and N₂O emissions that resulted from flares, expressed in metric tons CO_{2e} for each gas.

(7) For blowdown vent stack emission source, (refer to Equation W-14A and Equation W-14B of § 98.233), report the following:

(i) For each unique physical volume that is blown down more than once during the calendar year, report the following:

(A) Total number of blowdowns for each unique physical volume in the calendar year.

(B) Annual CO₂ and CH₄ emissions, for each unique physical blowdown volume, expressed in metric tons CO_{2e} for each gas.

(C) A unique name or ID number for the unique physical volume.

(ii) For all unique volumes that are blown down once during the calendar year, report the following:

(A) Total number of blowdowns for all unique physical volumes in the calendar year.

(B) Annual CO₂ and CH₄ emissions from all unique physical volumes as an aggregate per facility, expressed in metric tons CO_{2e} for each gas.

(8) * * *

(i) For wellhead gas-liquid separator with oil throughput greater than or equal to 10 barrels per day, using Calculation Methodology 1 and 2 of § 98.233(j), report the following by sub-basin category, unless otherwise specified:

* * * * *

(j) Annual CO₂ and CH₄ emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO₂e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j).

(k) Annual CO₂ and CH₄ gas quantities that were recovered, expressed in metric tons CO₂e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j).

(l) Annual CO₂, CH₄, and N₂O emissions that resulted from flaring gas, expressed in metric tons CO₂e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j).

(ii) For wells with oil production greater than or equal to 10 barrels per day, using Calculation Methodology 3 and 4 of § 98.233(j), report the following by sub-basin category:

* * * * *

(D) Sales oil API gravity range for wells in (c)(8)(ii)(B) and (c)(8)(ii)(C) of this section, in degrees.

* * * * *

(G) Annual CO₂ and CH₄ emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO₂e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of § 98.233(j).

(H) Annual CO₂ and CH₄ gas quantities that were recovered, expressed in metric tons CO₂e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of § 98.233(j).

(I) Annual CO₂, CH₄, and N₂O emissions that resulted from flaring gas, expressed in metric tons CO₂e for each gas, at the sub-basin level for Calculation Methodology 3 and 4 of § 98.233(j).

(iii) For wellhead gas-liquid separators and wells with throughput less than 10 barrels per day, using Calculation Methodology 5 of § 98.233(j)

Equation W-15 of § 98.233, report the following:

* * * * *

(F) Annual CO₂ and CH₄ emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO₂e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(G) Annual CO₂ and CH₄ gas quantities that were recovered, expressed in metric tons CO₂e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(H) Annual CO₂, CH₄, and N₂O emissions that resulted from flaring gas, expressed in metric tons CO₂e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(iv) * * *

(B) Annual CO₂ and CH₄ emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO₂e for each gas, at the sub-basin level for improperly functioning dump valves.

(9) For transmission tank emissions identified using optical gas imaging instrument per § 98.234(a) (refer to § 98.233(k)), or acoustic leak detection of scrubber dump valves, report the following:

(i) For each vent stack, report annual CO₂ and CH₄ emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO₂e for each gas.

(ii) For each transmission storage tank, report annual CO₂, CH₄, and N₂O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons CO₂e for each gas.

(iii) A unique name or ID number for the vent stack monitored according to 40 CFR 98.233(k).

(10) For well testing venting and flaring (refer to Equation W-17A or W-17B of § 98.233), report the following:

* * * * *

(iv) Report annual CO₂ and CH₄ emissions at the facility level, expressed in metric tons CO₂e for each gas, emissions from well testing venting.

(v) Report annual CO₂, CH₄, and N₂O emissions at the facility level, expressed in metric tons CO₂e for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation W-18 of § 98.233), report the following for each basin:

* * * * *

(iii) Report annual CO₂ and CH₄ emissions at the facility level, expressed in metric tons CO₂e for each gas,

emissions from associated natural gas venting.

(iv) Report annual CO₂, CH₄, and N₂O emissions at the facility level, expressed in metric tons CO₂e for each gas, emissions from associated natural gas flaring.

(12) * * *

(vi) Report uncombusted CH₄ emissions, in metric tons CO₂e (refer to Equation W-19 of § 98.233).

(vii) Report uncombusted CO₂ emissions, in metric tons CO₂e (refer to Equation W-20 of § 98.233).

(viii) Report combusted CO₂ emissions, in metric tons CO₂e (refer to Equation W-21 of § 98.233).

(ix) Report N₂O emissions, in metric tons CO₂e.

(x) For the natural gas processing industry segment, a unique name or ID number for the flare stack.

(xi) In the case that a CEMS is used to measure CO₂ emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO₂ and uncombusted CO₂ as a combined number.

* * * * *

(15) For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to § 98.233(q) and (r))

(i) * * *

(A) Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leaker emission factor in Tables W-2, W-3, W-4, W-5, W-6, and W-7 of this subpart.

(B) For onshore natural gas processing, range of concentrations of CH₄ and CO₂ (refer to Equation W-30 of § 98.233).

(C) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas (refer to parameter GHG_i in Equation W-30 of § 98.233), by component type.

(ii) * * *

(A) For source categories § 98.230(a)(4), (a)(5), (a)(6), (a)(7), and (a)(8), total count for each component type in Tables W-2, W-3, W-4, W-5, and W-6 of this subpart for which there is a population emission factor, listed by major heading and component type.

(B) For onshore production (refer to § 98.230 paragraph (a)(2)), total count for each type of major equipment in Table W-1B and Table W-1C of this subpart, by facility.

(C) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas (refer to Equation W-31 of § 98.233), by component type.

(16) For local distribution companies, report the following:

(i) Total number of above grade T-D transfer stations in the facility.

(ii) Number of years over which all T-D transfer stations will be monitored at least once.

(iii) Number of T-D stations monitored in calendar year.

(iv) Total number of below grade T-D transfer stations in the facility.

(v) Total number of above grade metering-regulating stations (this count will include above grade T-D transfer stations) in the facility.

(vi) Total number of below grade metering-regulating stations (this count will include below grade T-D transfer stations) in the facility.

(vii) [Reserved]

(viii) Leak factor for meter/regulator run developed in Equation W-32 of § 98.233.

(ix) Number of miles of unprotected steel distribution mains.

(x) Number of miles of protected steel distribution mains.

(xi) Number of miles of plastic distribution mains.

(xii) Number of miles of cast iron distribution mains.

(xiii) Number of unprotected steel distribution services.

(xiv) Number of protected steel distribution services.

(xv) Number of plastic distribution services.

(xvi) Number of copper distribution services.

(xvii) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all above grade T-D transfer stations combined.

(xviii) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all below grade T-D transfer stations combined.

(xix) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all above grade metering-regulating stations (including T-D transfer stations) combined.

(xx) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all below grade metering-regulating stations (including T-D transfer stations) combined.

(xxi) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all distribution mains combined.

(xxii) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all distribution services combined.

(17) * * *

(v) For each EOR pump, report annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each gas.

(18) For EOR hydrocarbon liquids dissolved CO₂ for each sub-basin category (refer to Equation W-38 of § 98.233), report the following:

* * * * *

(iii) Report annual CO₂ emissions at the sub-basin level, expressed in metric tons CO₂e.

(19) * * *

(iii) Report annual CO₂, CH₄, and N₂O emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, expressed in metric tons CO₂e for each gas, by type of unit.

* * * * *

(v) Cumulative number of internal fuel combustion units, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr or 130 horsepower, by type of unit.

(vi) Report annual CO₂, CH₄, and N₂O emissions from internal combustion units greater than 1mmBtu/hr, expressed in metric tons CO₂e for each gas, by type of unit.

(vii) Cumulative volume of fuel combusted in internal combustion units with a rated heat capacity larger than 1 mmBtu/hr or 130 horsepower, by fuel type.

* * * * *

(e) For onshore petroleum and natural gas production, report the best available estimate of API gravity, best available estimate of gas to oil ratio, and best available estimate of average low pressure separator pressure for each oil sub-basin category.

■ 9. Section 98.237 is amended by adding paragraph (e) to read as follows:

§ 98.237 Records that must be retained.

* * * * *

(e) The records required under § 98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.

■ 10. Section 98.238 is amended by:

■ a. Revising the definitions of "Facility with respect to natural gas distribution for purposes of this subpart and subpart A", "Facility with respect to onshore petroleum and natural gas production for purposes of this subpart and for subpart A", "Farm Taps", and "Transmission pipeline".

■ b. Adding definitions of "Associated with a single well-pad", "Distribution pipeline", "Flare", "Forced extraction", "Horizontal well", "Meter/regulator run", "Metering-regulating station", "Natural gas", "Pressure groups", "Sub-basin category", "Transmission-distribution transfer station", "Tubing diameter groups", "Tubing systems", "Vertical well", and "Well testing venting and flaring".

■ c. Removing the definitions of "Gas well" and "Oil well".

The revisions read as follows:

§ 98.238 Definitions.

* * * * *

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. The association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. Onshore production storage tanks on or associated with a single well-pad are considered a part of the onshore production facility.

* * * * *

Distribution pipeline means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3.

* * * * *

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements means all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO₂ EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

* * * * *

Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an

open or closed flame to combust waste gases without energy recovery.

* * * * *

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

Horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

* * * * *

Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow or both.

Metering-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and

carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

* * * * *

Pressure groups as applicable to each sub-basin are defined as follows: Less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig. The pressure in the context of pressure groups is either the well shut-in pressure; well casing pressure; or you may use the casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure for each well in the sub-basin.

* * * * *

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce from high permeability gas, shale gas, coal seam, or other tight reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil

formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

Transmission-distribution (T-D) transfer station means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission pipeline means a Federal Energy Regulatory Commission 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).

Tubing diameter groups are defined as follows: Outer diameter less than or equal to 1 inch; outer diameter greater than 1 inch and less than 2.375 inch; and outer diameter greater than or equal to 2.375 inch.

Tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

* * * * *

Vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

■ 11. Table W-1A to Subpart W of Part 98 is revised to read as follows:

TABLE A-1A OF SUBPART W—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION

Onshore petroleum and natural gas production	Emission factor (scf/hour/ component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service¹	
Valve	0.640
Connector	0.083
Open-ended Line	1.46
Pressure Relief Valve	0.97
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	10.3

TABLE A-1A OF SUBPART W—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION—Continued

Onshore petroleum and natural gas production	Emission factor (scf/hour/ component)
Population Emission Factors—All Components, Light Crude Service⁴	
Valve	0.04
Flange	0.002
Connector	0.005
Open-ended Line	0.04
Pump	0.01
Other ⁵	0.23
Population Emission Factors—All Components, Heavy Crude Service⁶	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004
Other ⁵	0.002
Western U.S.	
Population Emission Factors—All Components, Gas Service¹	
Valve	2.903
Connector	0.396
Open-ended Line	0.748
Pressure Relief Valve	4.631
Low Continuous Bleed Pneumatic Device Vents ²	1.77
High Continuous Bleed Pneumatic Device Vents ²	47.4
Intermittent Bleed Pneumatic Device Vents ²	17.1
Pneumatic Pumps ³	10.3
Population Emission Factors—All Components, Light Crude Service⁴	
Valve	0.04
Flange	0.002
Connector	0.005
Open-ended Line	0.04
Pump	0.01
Other ⁵	0.23
Population Emission Factors—All Components, Heavy Crude Service⁶	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004
Other ⁵	0.002

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."

■ 12. Table W-2 of Subpart W of Part 98 is revised to read as follows:

TABLE W-2 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Onshore natural gas processing plants	Emission factor (scf/hour/ component)
Leaker Emission Factors—Compressor Components, Gas Service	
Valve ¹	14.84
Connector	5.59
Open-Ended Line	17.27

TABLE W-2 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING—Continued

Onshore natural gas processing plants	Emission factor (scf/hour/ component)
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors—Non-Compressor Components, Gas Service	
Valve ¹	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93

¹ Valves include control valves, block valves and regulator valves.

- 13. Table W-3 to Subpart W of Part 98 is revised to read as follows:

TABLE W-3 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission factor (scf/hour/ component)
Leaker Emission Factors—Compressor Components, Gas Service	
Valve ¹	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors—Non-Compressor Components, Gas Service	
Valve ¹	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93
Population Emission Factors—Gas Service	
Low Continuous Bleed Pneumatic Device Vents ²	1.37
High Continuous Bleed Pneumatic Device Vents ²	18.20
Intermittent Bleed Pneumatic Device Vents ²	2.35

¹ Valves include control valves, block valves and regulator valves.

² Emission Factor is in units of "scf/hour/device."

- 14. Table W-4 to Subpart W of Part 98 is revised to read as follows:

TABLE W-4 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/ component)
Leaker Emission Factors—Storage Station, Gas Service	
Valve ¹	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33

TABLE W-4 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE—Continued

Underground natural gas storage	Emission factor (scf/hour/ component)
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.1
Pressure Relief Valve	0.17
Open Ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents ²	1.37
High Continuous Bleed Pneumatic Device Vents ²	18.20
Intermittent Bleed Pneumatic Device Vents ²	2.35

¹ Valves include control valves, block valves and regulator valves.
² Emission Factor is in units of "scf/hour/device."

■ 15. Table W-5 to Subpart W of Part 98 is revised to read as follows:

TABLE W-5 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG storage	Emission factor (scf/hour/ component)
Leaker Emission Factors—LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other ¹	1.77
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	4.17

¹ "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
² Emission Factor is in units of "scf/hour/device."

■ 16. Table W-6 to Subpart W of Part 98 is revised to read as follows:

TABLE W-6 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission factor (scf/hour/ component)
Leaker Emission Factors—LNG Terminals Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other ¹	1.77
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor ²	4.17

¹ "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
² Emission Factors is in units of "scf/hour/compressor."

■ 17. Table W-7 to subpart W of Part 98 is revised to read as follows:

TABLE W-7 OF SUBPART W—DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION

Natural gas distribution	Emission factor (scf/hour/ component)
Leaker Emission Factors—Transmission-Distribution Transfer Station¹ Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.27
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors—Below Grade Metering-Regulating station¹ Components, Gas Service²	
Below Grade M&R Station, Inlet Pressure > 300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure < 100 psig	0.10
Population Emission Factors—Distribution Mains, Gas Service³	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors—Distribution Services, Gas Service⁴	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

¹ Excluding customer meters.

² Emission Factor is in units of “scf/hour/station.”

³ Emission Factor is in units of “scf/hour/mile.”

⁴ Emission Factor is in units of “scf/hour/number of services.”