Petroleum and Natural Gas Systems

Subpart W, Greenhouse Gas Reporting Program

OVERVIEW

Subpart W of the Greenhouse Gas Reporting Program (GHGRP) (40 CFR 98.230 – 98.238) applies to any facility that contains petroleum and natural gas systems (and own and operate residue gas compression equipment) and meets the Subpart W source category definition. Some subparts have thresholds that determine applicability for reporting, and some do not. To decide whether your facility must report under this subpart, please refer to 40 CFR 98.291 and the GHGRP Applicability Tool.

This Information Sheet is intended to help facilities reporting under Subpart W understand how the source category is defined, what greenhouse gases (GHGs) must be reported, how GHG emissions must be calculated and shared with EPA, and where to find more information.

How is This Source Category Defined?

The Subpart W source category consists of emission sources in ten industry segments of the petroleum and natural gas industry:

- Onshore petroleum and natural gas production.
- Offshore petroleum and natural gas production.
- Onshore natural gas processing.
- Onshore natural gas transmission compression.
- Onshore petroleum and natural gas gathering and boosting.
- Onshore natural gas transmission pipelines.
- Underground natural gas storage.
- Liquefied natural gas (LNG) storage.
- LNG import and export equipment.
- Natural gas distribution.

Subpart W includes specific definitions of a “facility” for four of the ten industry segments at 40 CFR 98.238:

***Onshore petroleum and natural gas production*:**

- A facility is defined generally as all emission source types (see Table 1) on a single well pad or associated with a single well pad and carbon dioxide enhanced oil recovery (CO_2-EOR) operations that are under common ownership or control in a single hydrocarbon (HC) basin, as defined by the American Association of Petroleum Geologists (AAPG).

***Natural gas distribution*:**

- A facility generally is defined as the collection of all distribution pipelines and metering-regulating stations that are operated by a single 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.

Onshore petroleum and natural gas gathering and boosting:

- A facility is defined generally as all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single HC basin, as defined by the AAPG.

Onshore natural gas transmission pipeline:

- A facility is defined generally as the total U.S. mileage of natural gas transmission pipelines, as defined in this section, owned and operated by an onshore natural gas transmission pipeline owner or operator, as defined in this section.

For the rest of the industry segments, a facility is defined generally as all sources for which emission calculation methods are provided in the Greenhouse Gas Reporting Program (GHGRP) rule (found at 40 CFR Part 98, including those in Table 1 of this document) and that are located on a contiguous property and under common ownership or common control (see the definition of "facility" in Subpart A, General Provisions, found at 40 CFR 98.6). Because the rest of the industry segments share a common definition of "facility", owners and operators may need to report facility emissions under multiple industry segments as well as multiple subparts (e.g., Subpart C for combustion emissions).

What GHGs Must Be Reported?

Each facility that emits 25,000 metric tons or more of CO_2 equivalent (CO_2e) per year must report emissions to the EPA.

- Facilities in the four industry segments with unique facility definitions (see above) must report emissions to the EPA if the total emissions from the facility exceed the 25,000 metric tons reporting threshold.
- Facilities reporting under one or more of the other six industry segments in Subpart W that are defined more generally by Subpart A's General Provisions, found at 40 CFR 98.6 must report emissions to the EPA if the total emissions from the facility, including emissions from all applicable Subpart W industry segments, and any other applicable GHGRP subparts, exceed the 25,000 metric tons reporting threshold.

Each facility must report the greenhouse gas (GHG) emissions identified below for the emission source types listed in Table 1 for the applicable industry segment:

- CO_2 and methane (CH_4) emissions from equipment leaks and vented emissions.
- CO_2, CH_4, and nitrous oxide (N_2O) emissions from gas flares by following the requirements of Subpart W.
- CO_2, CH_4, and N_2O emissions from stationary and portable fuel combustion sources in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments by following the requirements in Subpart W.
- CO_2, CH_4, and N_2O emissions from stationary combustion sources in the natural gas distribution industry segment by following the requirements in Subpart W.
- CO_2, CH_4, and N_2O emissions from stationary combustion sources in all other industry segments (except onshore natural gas transmission pipeline) by following the requirements of Subpart C (General Stationary Fuel Combustion Sources) found at 40 CFR 98.30 – 98.38.

If multiple GHGRP source categories are co-located at a facility, the facility may need to report GHG emissions under a different subpart. Please refer to the relevant Information Sheet for a summary of the rule requirements for any other source categories located at the facility.

Table 1. Summary of Source Types by Industry Segment

Source Type	Offshore Petroleum and Natural Gas Production	Onshore Petroleum and Natural Gas Production	Onshore Natural Gas Processing	Onshore Natural Gas Transmission Compression	Underground Natural Gas Storage	LNG Storage	LNG Import and Export Equipment	Natural Gas Distribution	Onshore Petroleum and Natural Gas Gathering and Boosting	Onshore Natural Gas Transmission Pipeline
Natural gas pneumatic device venting		✓		✓	✓				✓	
Natural gas driven pneumatic pump venting		✓							✓	
Acid gas removal vents		✓	✓						✓	
Dehydrator venting and flaring		✓	✓						✓	
Well venting for liquids unloading		✓								
Gas well and oil well venting and flaring during completions and workovers with hydraulic fracturing		✓								
Gas well venting and flaring during completions and workovers without hydraulic fracturing		✓								
Blowdown vent stacks			✓	✓			✓		✓	✓
Atmospheric storage tank venting and flaring		✓							✓	
Transmission storage tank venting and flaring				✓						
Well testing venting and flaring		✓								
Associated gas venting and flaring		✓								
Flare stack emissions		✓*	✓*	✓*	✓	✓	✓		✓*	
Centrifugal compressor venting		✓	✓	✓	✓	✓	✓		✓	
Reciprocating compressor venting		✓	✓	✓	✓	✓	✓		✓	
Equipment leaks via leak surveys and leaker emission factors (EFs)		✓	✓	✓	✓	✓	✓	✓	✓	
Equipment leaks via population count and EFs		✓			✓	✓	✓	✓	✓	
Equipment leaks, vented emissions, and flare emissions identified in BOEM GOADS Study	✓									
EOR injection pump blowdown		✓								
EOR hydrocarbon liquids dissolved CO_2		✓								
Combustion emissions by following Subpart W		✓						✓	✓	
Combustion emissions by following Subpart C	✓		✓	✓	✓	✓	✓			

* Note that flaring emissions from dehydrators, completions and workovers, atmospheric storage tanks, transmission storage tanks, well testing, and associated gas are required to be reported under the applicable source type following the requirements specified for the source type in 40 CFR § 98.233. Flare emissions from all other source types must be determined in accordance with 40 CFR § 98.233(n) and reported under the flare stack emission source type in accordance with 40 CFR § 98.236(n).

How Must GHG Emissions Be Calculated?

Facilities must calculate GHG emissions according to the specified calculation methodologies in Subpart W of 40 CFR Part 98 for each source type within an industry segment. Where volumetric emissions are measured, mass emissions of CO_2, CH_4 and N_2O must be estimated based on the annual mole fraction and density of each GHG.

- The engineering calculation methods use monitored process operating parameters and either software models, engineering calculations, or emission factors (EFs).
- Direct measurement involves the use of the high-volume sampler; calibrated bagging; or rotameters, turbine meters, or other meters, as appropriate, depending on the individual component for emissions measurement.
- For leak detection, the rule allows the use of optical gas imaging instruments, organic vapor analyzers (OVA), toxic vapor analyzers (TVA) and infrared laser beam illuminated instruments or acoustic leak detection instruments for accessible components. For inaccessible components, reporters must use an optical gas imaging instrument or Method 21.[1]
- To use leaker EFs to quantify equipment leak emissions, the relevant EFs are applied to the number of leaking components as determined using an applicable instrument. If using population factors, the relevant EFs are applied to the total count of each type of component at the facility.

For Reporting Year 2024, the following additional calculation methodologies or revisions to the applicability of existing calculation methodologies have been added to optionally allow reporters to submit additional empirical data:

- Additional direct measurement methodologies are optionally available to quantify emissions from natural gas driven pneumatic devices and pumps, completions and workovers with hydraulic fracturing, associated gas venting and flaring, centrifugal and reciprocating compressors, and equipment leaks.
- A methodology was added to provide reporters with the option to use of leak detection instruments to identify malfunctioning intermittent bleed pneumatic devices, and to quantify emissions by applying different EFs to malfunctioning and properly operating devices.
- The applicability of existing calculation methodologies was optionally expanded for acid gas removal vents, dehydrator vents, atmospheric storage tanks, offshore production, and combustion equipment.

In addition, for Reporting Year 2024, the use of engineering estimates based on best available data is allowed to determine the temperature and pressure for emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities and onshore natural gas transmission pipeline facilities, and to determine the concentration of each constituent in the flow of gas to combustion units.

What Information Must Be Reported?

In addition to the information required by the General Provisions in Subpart A, found at 40 CFR 98.3(c), the following must be reported:

- Annual CO_2, CH_4, and N_2O emissions reported separately by industry segment.
- Within each industry segment, CO_2, CH_4, and N_2O emissions aggregated or individually for each source type, as specified. For example, an onshore natural gas production operation with multiple

[1] *See* 40 CFR Part 60, Subpart A (General Provisions), Appendix A-7, Test Method 21. Determination of volatile organic compound (VOC) leaks. This method is applicable for the determination of VOC leaks from process equipment. The sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals. This method is intended to locate and classify leaks only and is not to be used as a direct measure of mass emission rate from individual sources. While this test method pertains to VOC emissions, EPA has determined it is appropriate for GHG emissions as well.

reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

- Activity data as specified, either aggregated or individually for each source type.

For Reporting Year 2024, the EPA is also requiring the submittal of reporting elements necessary for the implementation of the Waste Emissions Charge (WEC), which consist of the annual quantities of natural gas and crude oil produced that is sent to sale for each well permanently shut-in and plugged.

What Records Must Be Maintained?

Reporters are required to retain records that pertain to their annual Greenhouse Gas Reporting Program (GHGRP) report for at least three years after the date the report is submitted. Please see the Subpart A Information Sheet and 40 CFR 98.3(g) for general recordkeeping requirements. Specific recordkeeping requirements for Subpart W are listed at 40 CFR 98.237.

When and How Must Reports be Submitted?

Reporters must submit their annual GHGRP reports for the previous calendar year to the EPA by March 31st, unless the 31st falls on a Saturday, Sunday, or federal holiday, in which case reports are due on the next business day. Annual reports must be submitted electronically using the electronic Greenhouse Gas Reporting Tool (e-GGRT), the GHGRP's online reporting system.

Additional information on setting up user accounts, registering a facility, and submitting annual reports is available on the GHGRP Help webpage.

When Can a Facility Stop Reporting?

A facility may discontinue reporting under several scenarios, which are summarized in the Subpart A Information Sheet.

For More Information

For additional information on Subpart W, visit the Subpart W webpage. For additional information on the GHGRP, please visit the GHGRP website, which includes additional information sheets, data previously reported to the GHGRP, training materials, and links to Frequently Asked Questions (FAQs). For questions that cannot be answered through the GHGRP website, please contact us at: GHGreporting@epa.gov.

This Information Sheet is provided solely for informational purposes. It does not replace the need to read and comply with the regulatory text contained in the rule. Rather, it is intended to help reporting facilities and suppliers understand key provisions of the GHGRP. It does not provide legal advice; have a legally binding effect; or expressly or implicitly create, expand, or limit any legal rights, obligations, responsibilities, expectations, or benefits with regard to any person or entity.