Petroleum and Natural Gas Systems

Final Rule: Subpart W of 40 CFR Part 98

United States Environmental Protection Agency

Under this final rule to 40 CFR Part 98, owners or operators of facilities that contain petroleum and natural gas systems (as defined below) and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalents) from process operations, stationary combustion, miscellaneous use of carbonates, and other source categories (see information sheet on General Provisions) will report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Owners or operators will collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting.

How Is This Source Category Defined?

Under this final rule, this source category consists of emission sources in the following segments of the petroleum and natural gas industry:

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

Who Must Report?

Facilities that emit 25,000 metric tons or more of CO_2e per year must report emissions to EPA. Part 98 defines three different types of facilities. You must apply the 25,000 ton per year threshold separately to each facility to determine if each facility must report.

- For the onshore petroleum and natural gas production industry segment, a facility[1] is defined generally as all emission source types (see Table 1) on a single well pad or associated with a single well pad and CO_2 EOR operations that are under common ownership or control in a single hydrocarbon basin, as defined by the American Association of Petroleum Geologists.

- For natural gas distribution industry segment, a facility[1] 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.

- For all other industry segments, the facility definition is the same as what is defined in the General Provisions to part 98. Under this definition, a facility is defined generally as all sources for which emission calculation methods are provided in 40 CFR part 98 (including those in Table

[1] See 40 CFR part 98, subparts A and W for the precise definition of each of the three "facility" types.

1) and that are located on a contiguous property and under common ownership or common control.

What Gases Must Be Reported?

Each facility must report:

- Carbon Dioxide (CO_2) and methane (CH_4) emissions from equipment leaks and vented emissions. Table 1 identifies the emission source types that each industry segment is required to report. For example, natural gas processing facilities must report emissions from eight specific source types, and underground storage facilities must report for six source types.
- 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 production industry segment 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 by following the requirements of 40 CFR 98 subpart C (General Stationary Fuel Combustion Sources).

Table 1. Summary of Source Types by Industry Segment

Source Type	Offshore Production	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression	Under-ground Storage	LNG Storage	LNG Import and Export Equipment	Distribution
Natural gas pneumatic device venting		X		X	X			
Natural gas driven pneumatic pump venting		X						
Acid gas removal vents		X	X					
Dehydrator vents		X	X					
Well venting for liquids unloading		X						
Gas well venting during completions and workovers from hydraulic fracturing		X						
Gas well venting during completions and workovers without hydraulic fracturing		X						
Blowdown vent stacks			X	X			X	
Onshore production		X						

Source Type	Offshore Production	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression	Under-ground Storage	LNG Storage	LNG Import and Export Equipment	Distribution
storage tanks								
Transmission storage tanks				X				
Well testing venting and flaring		X						
Associated gas venting and flaring		X						
Flare stack emissions[2]		X	X					
Centrifugal compressor venting		X	X	X	X	X	X	
Reciprocating compressor venting		X	X	X	X	X	X	
Leak detection and leaker emission factors			X	X	X	X	X	X
Population count and emissions factors		X			X	X	X	X
Equipment leaks, vented emission, and flare emissions identified in BOEM GOADS Study	X							
Enhanced Oil Recovery (EOR) injection pump blowdown		X						
EOR hydrocarbon liquids dissolved CO_2		X						
Combustion emissions by following subpart W		X[3]						X[3]
Combustion emissions by following subpart C	X		X	X	X	X	X	

[2] You must report flaring emissions from each applicable source type by following the flare requirements specified for the source type in 40 CFR 98.233. For the onshore petroleum and natural gas production industry segment and the natural gas processing industry segment, you also must account for the flare emissions from all other source types, by following the requirements in section 40 CFR 98.233(n).
[3] Excludes external combustion units of 5 MMBtu/hour or less, and internal combustion engines of 1 MMBtu/hour or less.

How Are Greenhouse Gas Emissions 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.
- 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[4].
- For the use of leaker emission factors, the relevant emission factors will be applied to leaking components determined by using an applicable instrument. For the use of population factors, the relevant emission factors will be applied to each component type.

When Does Reporting Begin?

Facilities subject to subpart W began monitoring GHG emissions on January 1, 2011 in accordance with the methods specified in subpart W. For 2012 only, the GHG report must be submitted to EPA by September 28, 2012. This reporting deadline applies to all subparts being reported by the facility. If your subpart W facility submitted a GHG annual report for reporting year 2010 under another subpart (e.g., subpart C for general stationary fuel combustion), then by April 2, 2012 you must have notified EPA through e-GGRT that you are not required to submit the second annual report until September 28, 2012.

Starting in 2013 and each year thereafter, reports must be submitted to EPA by March 31 of each year, unless the 31st is a weekend or federal holiday, in which case the reports are due on the next business day.

What Information Must be Reported?

Under the final rule, covered facilities will report the following information:

- Annual CO_2, $CH_{4,}$ and N_2O emissions reported separately for onshore petroleum and natural gas production, offshore 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, and natural gas distribution.
- 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

4 40 CFR part 60, subpart A (General Provisions), Appendix A-7, Test Method 21 – Determination of volatile organic compound 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 VOCs, EPA has determined it is appropriate for GHG's 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.
- Annual throughput for each facility.
- CO_2, CH_4, and N_2O emissions reported separately for portable equipment.

EPA has temporarily deferred the requirement to report data elements in the above list that are used as inputs to emission equations. Table A-7 of 40 CFR Part 98 subpart A lists the deferred data elements. For the current status of reporting requirements, including *Federal Register* notices that explain the basis for the deferrals, consult the following link: http://www.epa.gov/ghgreporting/reporters/cbi/index.html

For More Information

This document is provided solely for informational purposes. It does not provide legal advice, have legally binding effect, or expressly or implicitly create, expand, or limit any legal rights, obligations, responsibilities, expectations, or benefits in regard to any person. The series of information sheets is intended to assist reporting facilities/owners in understanding key provisions of the rule. They are not intended to be a substitute for the rule.

Visit EPA's web site (http://www.epa.gov/ghgreporting/index.html) or the subpart W web site (http://www.epa.gov/ghgreporting/reporters/subpart/w.html) for more information and additional information sheets.