

Petroleum and Natural Gas Systems



Final Rule: Subpart W of 40 CFR Part 98

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 CO₂e per year must report. The rule defines three different types of facilities. You must apply the 25,000 ton per year threshold separately to each facility to determine if that facility must report.

- For the onshore petroleum and natural gas production industry segment, a facility¹ is defined generally as all emission source types (see Table 1) on a well pad or associated with a well pad 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 facility¹ generally is defined as the collection of all pipelines, metering stations, and regulating stations that are operated by a single local distribution company.
- For all other industry segments, use the facility definition 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) and that are located on a contiguous property and under common ownership or common control.

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

What Gases Must Be Reported?

Each facility must report:

- Carbon Dioxide (CO₂) and methane (CH₄) emissions from equipment leaks and vented emissions. Table 1 identifies each source type that industry segments are required to report. For example, natural gas processing facilities must report emissions from seven specific source types, and underground storage must report for five source types.
- CO₂, CH₄, and nitrous oxide (N₂O) emissions from gas flares by following the requirements of subpart W.
- CO₂, CH₄, and N₂O emissions from stationary and portable fuel combustion sources in the onshore production industry segment following the requirements in subpart W.
- CO₂, CH₄, and N₂O emissions from stationary combustion sources in the natural gas distribution industry segment following the requirements in subpart W.
- CO₂, CH₄, and N₂O emissions from all other applicable stationary combustion sources 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 vent		X	X					
Dehydrator vent		X	X					
Well venting for liquids unloading		X						
Gas well venting during well completions and workovers with hydraulic fracturing		X						
Gas well venting during well completions and workovers without hydraulic fracturing		X						
Blowdown vent stacks			X	X			X	
Onshore production storage tanks		X						
Transmission storage tanks				X				
Well testing venting and		X						

Source Type	Offshore Production	Onshore Production	Natural Gas Processing	Natural Gas Transmission Compression	Underground Storage	LNG Storage	LNG Import and Export Equipment	Distribution
flaring								
Associated gas venting and flaring		X						
Flare stacks ²		X	X					
Centrifugal compressor venting		X	X	X	X	X	X	
Reciprocating compressor rod packing venting		X	X	X	X	X	X	
Other emissions from equipment leaks		X	X	X	X	X	X	X
Population Count and Emissions Factor		X			X	X	X	X
Vented, Equipment Leaks and Flare Emissions Identified in BOEMRE GOADS Study	X							
Enhanced Oil Recovery hydrocarbon liquids dissolved CO ₂		X						
Enhanced Oil Recovery injection pump blowdown		X						
Onshore Petroleum and Natural Gas Production and Natural Gas Distribution Combustion Emissions		X						X

How Are Greenhouse Gas Emissions Calculated?

Under this rule, facilities will detect, as applicable, and calculate GHG emissions according to the specified quantification methods. Table 2 summarizes the calculation methodologies by source type. Where volumetric emissions are measured, mass emissions of CO₂ and CH₄ will 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.

² Calculation methodologies for determining flare emissions are outlined in subpart W under applicable emissions sources.

- For emissions 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.
- Direct measurement involves the use of the high-volume sampler; or calibrated bagging; or rotameters, turbine meters, or other meters, as appropriate, depending on the individual component for emissions measurement.
- For the use of leaking factors, the relevant emission factors will be applied to leaking components determined by using an applicable instrument and applying leaking factors. For the use of population factors, the relevant emission factor will be applied to all components.

When Does Reporting Begin?

Facilities subject to subpart W must begin 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 notify EPA through e-GGRT that you are not required to submit the second annual report until September 28, 2012 (the notification deadline according to 4 CFR 98.3(b) is March 31, 2012, however, because this date falls on a Saturday in 2012, the notification is due on the next business day).

Starting in 2013 and each year thereafter, reports must be submitted to EPA by March 31 of each year, unless the 31st is a Saturday, Sunday, 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 CO₂, CH₄, and N₂O emissions reported separately for onshore and 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 terminals, and natural gas distribution.
- Within each industry segment, CO₂, CH₄, and N₂O emissions aggregated or individually for each source type as specified. For example, an onshore natural gas production operation with multiple 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.
- CO₂, CH₄, and N₂O emissions reported separately for portable equipment.
- For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both.

EPA has temporarily deferred the requirement to report data elements in the above list that are used as inputs to emission equations (76 FR 53057, August 25, 2011). For the current status of reporting requirements, including the list of data elements that are considered to be inputs to emissions equations, consult the following link: <http://www.epa.gov/climatechange/emissions/CBI.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 (www.epa.gov/climatechange/emissions/ghgrulemaking.html) for more information and additional information sheets, or go to www.regulations.gov to access the rulemaking docket EPA-HQ-OAR-2009-0923.

Table 2. Emission Calculation Methods

Source Type	Engineering Estimates	Direct Measurement	Leak Detection and Leaker Emission Factor	Equipment Count and Population Emission Factor
Natural gas pneumatic device venting				X
Natural gas driven pneumatic pump venting				X
Well venting for liquids unloading	X	X		
Gas well venting during well completions without hydraulic fracturing	X			
Gas well venting during well completions with hydraulic fracturing		X		
Gas well venting during well workovers without hydraulic fracturing	X			
Gas well venting during well workovers with hydraulic fracturing		X		
Onshore production storage tanks	X			X
Transmission storage tanks		X		
Reciprocating compressor rod packing venting		X		
Well testing venting and flaring	X			
Associated gas venting and flaring	X			
Dehydrator vent stacks	X			X
EOR injection pump blowdown	X			
Acid gas removal vent stack	X	X		
EOR hydrocarbon liquids dissolved CO ₂		X		
Centrifugal compressor wet seal degassing venting		X		
Other emissions from equipment leaks			X ^{2,3,4,5,6,7}	X ^{1,4,5,6,7}
Blowdown vent stacks	X			
Flare stacks	X	X		
Stationary and portable combustion emissions	X	X		
Above ground meters and regulators at city gate station equipment leaks			X	
Below ground meter and regulator station equipment leaks				X
Pipeline main equipment leaks				X
Service line equipment leaks				X

Note: Applicable only to the industry segments enumerated as follows: 1. Production 2. Processing 3. Transmission Compression 4. Underground storage 5. LNG storage 6. LNG Import and Export 7. Distribution. Sources with multiple methods indicate options for monitoring.