Petroleum Refineries

Final Rule: Mandatory Reporting of Greenhouse Gases

United States Environmental Protection Agency

Under the Mandatory Reporting of Greenhouse Gases (GHGs) rule, owners or operators of facilities that refine petroleum must report emissions from petroleum refining processes and all other source categories located at the facility for which methods are defined in the rule. Owners or operators are required to collect feedstock and product or emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting.

Facilities that refine petroleum also are required to report emissions under 40 CFR part 98, subpart MM (Suppliers of Petroleum Products).

How Is This Source Category Defined?

Petroleum refineries are facilities that produce gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) by the distillation of petroleum or the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

What GHGs Must Be Reported?

The refinery processes and gases that must be reported are listed in the table below along with the rule subpart that specifies the calculation methodology that must be used. *Please note the table key on page 2.*

For this refinery process…	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated…		
	Carbon Dioxide (CO_2)	Methane (CH_4)	Nitrous Oxide (N_2O)
Stationary combustion	C	C	C
Stationary combustion using fuel gas	C: Tier 3 (Equation C-5) or Tier 4[1]	C	C
Flares	Y	Y	Y
Catalytic cracking	Y	Y	Y
Traditional fluid coking	Y	Y	Y
Fluid coking with flexicoking design	C/Y	C/Y	C/Y
Catalytic reforming	Y	Y	Y
Onsite and offsite sulfur recovery	Y	-	-
Coke calcining	Y	Y	Y
Asphalt blowing	Y	Y	-
Equipment leaks	-	Y	-
Storage tanks	-	Y	-
Delayed coking	-	Y	-
Other process vents	Y	Y	Y
Uncontrolled blowdown systems	-	Y	-
Loading operations	-	Y	-
Hydrogen plants (nonmerchant)	P	P	-

[1.] For CO_2 emissions from combustion of fuel gas, the Tier 3 (equation C-5) or Tier 4 methodology must be used, as stated in the rule. Rule text supersedes preamble text when inconsistencies occur.

Key:

C = 40 CFR part 98, subpart C (General Stationary Combustion Sources)
P = 40 CFR part 98, subpart P (Hydrogen Production)
Y = 40 CFR part 98, subpart Y (Petroleum Refineries)
- = Reporting from this process is not required

For refinery processes that are subject to subparts other than 40 CFR part 98, subpart Y, the information sheets for 40 CFR part 98, subparts C and P summarize the requirements for calculating and reporting emissions.

How Should GHG Emissions Be Calculated?

Under 40 CFR part 98, subpart Y, owners or operators of petroleum refineries must calculate CH_4 and N_2O emissions using the calculation methods described below for each refinery process.

For CO_2 emissions, owners or operators must use one of two alternative methods:

- For applicable processes, refinery units with certain types of continuous emission monitoring systems (CEMS) in place must report using the CEMS and follow the Tier 4 methodology of 40 CFR part 98, subpart C to report combined process and combustion CO_2 emissions.
- For refinery units without CEMS in place, reporters can elect to either:
  (1) Install and operate a CEMS to measure combined process and combustion CO_2 emissions according to the requirements specified in 40 CFR part 98, subpart C; or
  (2) Calculate CO_2 emissions using the methods summarized below.

Flares

CO_2 emissions from flares must be calculated using the gas flow rate (either measured with a continuous flow meter or estimated using engineering calculations) and either:

1) The daily or weekly measured carbon content of the flare gas; or
2) The daily or weekly measured heat content of the flare gas and a default emission factor provided in the rule.

If the carbon content and heat content of the gas are not measured at least weekly, engineering estimates of heat content during normal flare use may be used, but CO_2 emissions from each startup, shutdown, and malfunction event exceeding a certain threshold must be calculated separately, also using engineering estimates. CH_4 and N_2O emissions from flares must be calculated using the emission factors specified in 40 CFR part 98, subpart C.

Catalytic Cracking Units, Fluid Coking Units

For catalytic cracking units and fluid coking units with rated capacities greater than 10,000 barrels per stream day (bbls/sd), continuously, or no less frequently than hourly, monitor the oxygen (O_2), CO_2, and (if necessary) carbon monoxide (CO) concentrations in the exhaust stacks from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels. Calculate CO_2 emissions using the volumetric flow rate of the exhaust gas (measured or calculated) and the measured CO and CO_2 concentrations in the exhaust stacks.

For catalytic cracking units and fluid coking units with rated capacities of 10,000 bbls/sd or less, either:

1) Monitor continuously or no less than daily the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to

the combustion of other fossil fuels, and calculate CO_2 emissions using the same method used for units with rated capacities greater than 10,000 bbls/sd; or

2) Calculate CO_2 emissions from each catalytic cracking unit and fluid coking unit using a coke burn-off factor and the carbon content of the coke (either measured or default value).

If there is a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, determine the CO_2 emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C and report those emissions by following the requirements of subpart C.

Calculate CH_4 and N_2O emissions using unit-specific measurement data, unit-specific emission factors based on a source test of the unit, or the equations specified in the rule. Fluid coking units that use the flexicoking design may account for their GHG emissions either by using the methods specified for traditional fluid coking units, or by using the methods for stationary combustion specified in 40 CFR part 98, subpart C.

Catalytic Reforming Units

For catalytic reforming units either:

1) Monitor continuously, or no less frequently than daily, the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, and calculate CO_2 emissions according to the same requirements of 40 CFR part 98.253(c)(2)(i) through (iii) for catalytic cracking units and fluid coking units with rated capacities of 10,000 bbls/sd or less; or
2) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using the quantity of coke burned off, the carbon content of the coke (measured or default value), and the number of regeneration cycles.

Calculate CH_4 and N_2O emissions using the same methods specified in 40 CFR part 98.253(c)(4) and (5) for catalytic cracking units and traditional fluid coking units.

Onsite and Offsite Sulfur Recovery

CO_2 emissions must be calculated using the volumetric flow rate of the sour gas (measured continuously or estimated from engineering calculations) and the carbon content of the sour gas stream (using a measured or a default value).

Coke Calcining Units

CO_2 emissions must be calculated from the difference between the carbon input as green coke and the carbon output as marketable petroleum coke, and as coke dust collected in the dust collection system. Calculate CH_4 and N_2O emissions using the same methods specified in 40 CFR part 98.253(c)(4) and (5) for catalytic cracking units and traditional fluid coking units.

Asphalt Blowing Operations

For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, CO_2 and CH_4 emissions must be calculated using facility-specific emission factors based on test data or, where test data are not available, default emission factors provided in the rule. For asphalt blowing operations controlled by a thermal oxidizer or flare, CH_4 and CO_2 emissions must be calculated by assuming that 98 percent of the CH_4 and other hydrocarbons generated by the asphalt blowing operation are converted to CO_2.

Equipment Leaks

CH_4 emissions from equipment leaks must be calculated using either default emission factors or process-specific CH_4 composition data and leak data collected using the leak detection methods specified in EPA's Protocol for Equipment Leak Emission Estimates.

Storage Tanks

For storage tanks, the calculation methodology used to calculate the CH_4 emissions depends on the material stored. For storage tanks used to store unstabilized crude oil, facilities must use either:

1) The tank-specific CH_4 composition data (based on direct measurement or product knowledge) and the measured gas generation rate; or
2) An emission factor-based method using the quantity of unstabilized crude oil received at the facility, the pressure difference between the previous storage pressure and atmospheric pressure, the mole fraction of CH_4 in the vented gas (using either a measured or a default value), and an emission factor provided in the rule.

For storage tanks that have a vapor-phase CH_4 concentration of 0.5 percent by volume or more and store material other than unstabilized crude oil, facilities must use either:

1) The tank-specific CH_4 composition data and the emission estimation methods provided in Section 7.1 of the AP-42: *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*; or
2) The default emission factor specified in the rule.

Note that CH_4 emissions from storage tanks do not need to be calculated for storage tanks meeting the conditions specified in 40 CFR part 98.253 (m)(3).

Delayed Coking Units

CH_4 emissions from the depressurization of delayed coking vessels must be calculated by either:

1) Following the method outlined below for other process vents and calculating the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations (if water or steam is added to the vessel after it is vented to the atmosphere, this option must be used); or
2) Calculating the CH_4 emissions from the depressurization vent, the subsequent opening of the vessel for coke cutting operations, and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere.

Other Process Vents

GHG emissions from other process vents that contain CO_2, CH_4, or N_2O exceeding concentration thresholds specified in the rule must be calculated using the volumetric flow rate, the mole fraction of the GHG in the exhaust gas, and the number of hours per venting event.

Uncontrolled Blowdown Systems

CH_4 emissions from uncontrolled blowdown systems must be calculated using either the mass balance method specified for process vents or a default emission factor and the sum of crude oil and intermediate products received from off site and processed at the facility.

Loading Operations

CH_4 emissions from loading operations must be calculated using the method in Section 5.2 of *AP-42: Compilation of Air Pollution Emission Factors, Volume 1: Stationary Point and Area Sources.* Facilities must calculate CH_4 emissions only for loading materials that have an equilibrium vapor-phase CH_4 concentration equal to or greater than 0.5 percent by volume.

A checklist for data that must be monitored is available at: www.epa.gov/ghgreporting/documents/pdf/checklists/PetroleumRefineries.pdf.

When Must Reports be Submitted?

The submission date for the annual GHG report can vary in the first 3 years of the program.

- Reporting Year 2010. The report was required to be submitted by September 30, 2011.

- Reporting Year 2011. The due date depends on which source categories are included in the report. If the report includes one or more of the source categories listed below, then the report must be submitted by September 28, 2012. This reporting deadline applies to all subparts being reported by the facility. In addition, if the facility contains one or more of these source categories and the 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).
    - Electronics Manufacturing (subpart I)
    - Fluorinated Gas Production (subpart L)
    - Magnesium Production (subpart T)
    - Petroleum and Natural Gas Systems (subpart W
    - Use of Electric Transmission and Distribution Equipment (subpart DD)
    - Underground Coal Mines (subpart FF)
    - Industrial Wastewater Treatment (subpart II)
    - Geologic Sequestration of Carbon Dioxide (subpart RR)
    - Manufacture of Electric Transmission and Distribution (subpart SS)
    - Industrial Waste Landfills (subpart TT)
    - Injection of Carbon Dioxide (subpart UU)
    - Imports and Exports of Equipment Pre–charged with Fluorinated GHGs or Containing Fluorinated GHGs in Closed–cell Foams (subpart QQ)

  If the report contains none of the source categories listed above, then the report must be submitted by April 2, 2012 (the deadline is March 31, 2012, however, because this date falls on a Saturday, the annual report is due on the next business day).

- Reporting Year 2012. Starting in 2013 and each year thereafter, the report must be submitted 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?

In addition to the information required by the General Provisions at 40 CFR 98.3(c), refineries must report the data used to identify emission units and calculate the GHG emissions (e.g., unit ID, unit type, feed input, GHG calculation method). In addition, facilities must report GHG emissions at the unit level for each catalytic cracking unit, coking unit, catalytic reforming unit, onsite and offsite sulfur recovery plant, coke calcining unit, and process vent.

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/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 final rule.

Visit EPA's Web site (www.epa.gov/ghgreporting/reporters/index.html) for more information, including the final preamble and rule, additional information sheets on specific industries, the schedule for training sessions, and other documents and tools. For questions that cannot be answered through the Web site, please contact us at: GHGreporting@epa.gov.