Petroleum Refineries Monitoring Checklist

Subpart Y, Greenhouse Gas Reporting Program

For flares, measure these parameters …

Carbon Dioxide Emissions

If you monitor carbon content at least weekly:

- ☐ Volume of flare gas combusted during measurement period (daily or weekly) (standard cubic feet (scf)/period)
- ☐ Average molecular weight of flare gas combusted during measurement period (daily or weekly) (kilogram (kg)/kilogram-mole)
- ☐ Average carbon content of flare gas combusted during measurement period (daily or weekly) (kg C/kg flare gas)

Or:

- ☐ Volume of flare gas combusted during measurement period (daily or weekly) (scf/period)
- ☐ Mole percent CO_2 concentration in the flare gas stream during the measurement period (mole percent = percent by volume)
- ☐ Mole percent concentration of compound "x" in the flare gas stream during the measurement period (mole percent = percent by volume)

If you monitor heat content at least weekly:

- ☐ Volume of flare gas combusted during measurement period (daily or weekly) (million (MM) scf/period)
- ☐ Higher heating value (HHV) for flare gas during measurement period (daily or weekly) (British thermal units (Btu/scf = mmBtu/MMscf)

If you do not measure the higher heating value or carbon content of the flare gas at least weekly:

- ☐ Annual volume of flare gas combusted during normal operations from company records (MMscf/year)
- ☐ HHV for fuel gas or flare gas from company records (Btu/scf = mmBtu/MMscf)
- ☐ Number of start-up, shutdown, and malfunction events during the year exceeding 500,000 scf/day
- ☐ Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event (scf/event)
- ☐ Average molecular weight of the flare gas during indexed start-up, shutdown, or malfunction event (kg/kg-mole)
- ☐ Average carbon content of flare gas combusted during indexed start-up, shutdown, or malfunction event (kg C/kg flare gas)

Methane emissions (optional)

☐	Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas) (If not monitored, must use default of 0.4)	Note: The reporting of methane and nitrous oxide emissions from flares is required. The alternative calculation methods involve the use of default emission factors and fuel volumes and do not require monitoring beyond what is included on the checklist.

For catalytic cracking units and traditional fluid coking units with rated capacities greater than 10,000 barrels per stream day, measure these parameters…

Carbon Dioxide Emissions

- ☐ Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)
- ☐ Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When there is no post-combustion device, assume % CO to be zero

You must also determine the hourly average exhaust gas flow rate from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels by monitoring:

- ☐ Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry scfh)

Or if using equation Y-7a:

- ☐ Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)
- ☐ Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)
- ☐ Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)
- ☐ Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)
- ☐ Oxygen concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume—dry basis)
- ☐ Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required under 40 CFR part 63 subpart UUU, assume % CO to be zero

Or if using equation Y-7b:

- ☐ Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)
- ☐ Nitrogen (N_2) concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on measured value or maximum N_2 impurity specifications of the oxygen supply used for enrichment (percent by volume – dry basis)
- ☐ Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)
- ☐ Hourly average percent N_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)

Methane and nitrous oxide emissions

Calculate emissions using either unit specific measurement data, a unit specific emission factor based on a source test of the unit, or default values provided in the rule.

If you operate and maintain a CEMS for catalytic cracking units or fluid coking units, in addition to the Tier 4 Calculation Methodology and associated requirements specified in 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources), monitor these parameters if applicable…

- ☐ Fuel use in the CO boiler or other post-unit combustion device

If you do not operate a CEMS for catalytic cracking units and traditional fluid coking units with rated capacities of 10,000 barrels per stream day or less (if you do not continuously or no less frequently than daily monitor the O2, CO2, and, if necessary, CO concentrations in the exhaust stack), measure these parameters…

Carbon dioxide emissions

- ☐ Annual throughput of unit from company records (barrels/yr)
- ☐ [Optional] Carbon content of coke based on measurement or engineering estimate (kg C/kg coke) (If not based on measurement or engineering estimate, must use default of 0.94)
- ☐ [Optional] Coke burn-off factor from engineering calculations (kg coke/barrel of feed) (If not monitored, must use default of 7.3 for catalytic cracking units or default of 11 for fluid coking units)

Methane and nitrous oxide emissions

Calculate emissions using either unit specific measurement data, a unit specific emission factor based on a source test of the unit, or default values provided in the rule.

If you do not operate a CEMS for fluid coking units that use flexicoking design, measure these parameters…

Use methods described in 40 CFR 98, subpart C (General Stationary Combustion Sources) or monitor same parameters for traditional fluid coking units.

If you do not operate a CEMS for catalytic reforming units, but you continuously or no less frequently than daily monitor 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, calculate emissions following the requirements of catalytic cracking units with rated capacities greater than 10,000 barrels per stream day; otherwise, measure these parameters…

Carbon dioxide emissions

- ☐ Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle)
- ☐ Number of regeneration cycles in year
- ☐ [Optional] Carbon content of coke based on measurement or engineering estimate (kg C/kg coke); If not based on measurement or engineering estimate, must use default of 0.94

Methane and nitrous oxide emissions

Calculate emissions using either unit specific measurement data, a unit specific emission factor based on a source test of the unit, or default values provided in the rule.

If you operate and maintain a CEMS for sulfur recovery plants, in addition to the Tier 4 Calculation Methodology and associated requirements specified in 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources), monitor this parameter…

- ☐ Fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via the final exhaust stack from the sulfur recovery plant

If you do not operate a CEMS for onsite sulfur recovery plants and for sour gas sent off site for sulfur recovery, measure these parameters…

Carbon Dioxide Emissions

- ☐ Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant, from measurement if available, engineering calculations, or company records (scf/year)
- ☐ [Optional] Mole fraction of carbon in the sour gas to the sulfur recovery plant, from measurement if available or engineering calculations (kg-mole C/kg-mole gas); If not based on measurement or engineering calculations, must use default of 0.20

Non-Claus sulfur recovery units may alternatively elect to monitor:

- ☐ Number of venting events per year
- ☐ Venting time for the event (hours)
- ☐ Average volumetric flow rate of process gas during the event (scf/hour) [or this may be determined from process knowledge or engineering estimates]
- ☐ Mole fraction of CO_2 in process vent during the event (kg-mol GHG/kg-mol vent gas) [or this may be determined from process knowledge or engineering estimates]

If you operate and maintain a CEMS for coke calcining units, in addition to the Tier 4 Calculation Methodology and associated requirements specified in 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources), monitor this parameter…

- ☐ Fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit

If you do not operate a CEMS for coke calcining units, measure these parameters…

Carbon Dioxide Emissions

- ☐ Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year)
- ☐ Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year)
- ☐ Average mass fraction carbon content of green coke from facility measurement data (metric ton C/metric ton green coke)
- ☐ Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton C/metric ton petroleum coke)
- ☐ Annual mass of marketable petroleum coke produced by coke calcining unit from facility records (metric tons petroleum coke/year)

Methane and nitrous oxide emissions

Calculate emissions using either unit specific measurement data, a unit specific emission factor based on a source test of the unit, or default values provided in the rule.

For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, measure these parameters…

The same methods (and thus same parameters measured) to estimate emissions as "Other process vents" can be used. Alternatively, the following parameters can be measured to calculate emissions in conjunction with other emission/conversion factors:

Carbon dioxide emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ [Optional] Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); If not based on facility-specific test data must use default of 1,100.

Methane emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ [Optional] Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); If not based on facility-specific test data must use default of 580

For controlled asphalt blowing operations, measure these parameters…

The same methods (and thus same parameters measured) to estimate emissions as "Other process vents" can be used. Alternatively, the following parameters can be measured to calculate emissions in conjunction with other emission/conversion factors:

Carbon Dioxide Emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ [Optional] Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); If not based on facility-specific test data must use a default of= 2,750
- ☐ [Optional] Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); If not based on facility-specific test data must use a default of 1,100

Methane Emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ [Optional] Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); If not based on facility-specific test data must use a default of 580

For delayed coking units, measure these parameters…

Methane Emissions

On December 9, 2016 (81 FR 89261), the EPA finalized amendments to the DCU emissions calculation methodology. The new method estimates emissions from DCU using a steam generation model. Key inputs to this heat balance include the mass of water and coke in the coke drum vessel and the average temperature of the coke drum contents when venting first occurs. As an alternative to monitoring the average temperature of the coke drum, the calculation method provides a temperature-pressure correlation. Finally, if a reporter has DCU vent gas measurements, these measurements can be used to develop a unit-specific methane emissions factor for the DCU. These amendments are effective January 1, 2019 for the RY 2018 report (which must be submitted by March 31, 2019). Reporters must begin to collect the data necessary to calculate emissions in accordance with the amended method beginning January 1, 2018.

Mass Coke in the Coke Drum Vessel:

- ☐ Typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle from company records (metric tons/cycle)

Or:

- ☐ Height of coking unit vessel (feet)
- ☐ Diameter of coking unit vessel (feet)
- ☐ Typical distance from the top of the delayed coking unit vessel to the top of the coke bed (i.e., coke drum outage) at the end of the coking cycle (feet) from company records or engineering estimates.

Mass of Water in the Coke Drum Vessel:

- ☐ Diameter of coking unit vessel (feet)
- ☐ Typical distance from the bottom of the coking unit vessel to the top of the water level at the end of the cooling cycle just prior to atmospheric venting (feet) from company records or engineering estimates.

Average Temperature of the Coke Drum Vessel:

- ☐ Temperature of the delayed coking unit vessel overhead line measured as near the coking unit vessel as practical just prior to venting to the atmosphere. If the temperature of the delayed coking unit vessel overhead line is less than 216 °F, use a value of 216 °F.
- ☐ Temperature of the delayed coking unit vessel near the bottom of the coke bed. If the temperature at the bottom of the coke bed is less than 212 °F, use a value of 212 °F.

Or:

- ☐ Pressure of the delayed coking unit vessel just prior to opening the atmospheric vent (pounds per square inch gauge, psig).

Methane Emissions Calculation:

- ☐ [Optional] Methane emission factor for delayed coking unit (kilograms CH_4 per metric ton of steam; kg CH_4/mt steam) from unit-specific measurement data. If you do not have unit-specific measurement data, use the default value of 7.9 kg CH_4/metric ton steam.
- ☐ Cumulative number of decoking cycles (or coke-cutting cycles) for all delayed coking unit vessels associated with the delayed coking unit during the year.

For other process vents that exceed the volume percent thresholds provided in the rule, measure these parameters…

For Each Greenhouse Gas

☐	Number of venting events per year	☐	Venting time for the event (hours)
☐	[Optional] Average volumetric flow rate of process gas during the event (scf/hour) [or this may be determined from process knowledge or engineering estimates].	☐	[Optional] Mole fraction of each GHG in process vent during the event (kg-mol GHG/kg-mol vent gas) [or this may be determined from process knowledge or engineering estimates]

For uncontrolled blowdown systems, measure these parameters…

The same methods (and thus same parameters measured) to estimate emissions as "Other process vents" can be used. Alternatively, the following parameters can be measured to calculate emissions in conjunction with other emission/conversion factors:

☐	Annual quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year)	☐	[Optional] Methane emission factor for uncontrolled blown systems (scf CH_4/MMbbl); If emission factor is not monitored, must use default of 137,000

For equipment leaks, measure these parameters…

☐ Process-specific CH_4 composition (from measurement data or process knowledge)

Or:

☐ Number of atmospheric crude oil distillation columns at the facility

☐ Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility

☐ Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility

☐ Number of hydrogen plants at the facility

☐ Number of fuel gas systems at the facility

For storage tanks (other than those processing unstabilized crude oil) that have a vapor-phase methane concentration of 0.5 volume percent or more, measure these parameters…

☐ Tank-specific [liquid-phase] CH_4 composition (from measurement data or product knowledge).

Or:

☐ Annual quantity of crude oil plus the quantity of intermediate products received from offsite that are processed at the facility (MMbbl/year)

For storage tanks that process unstabilized crude oil, measure these parameters…

- ☐ Tank-specific [vapor-phase] CH_4 composition (from measurement data or product knowledge)
- ☐ Gas generation rate

Or:

- ☐ Annual quantity of unstabilized crude oil received at the facility (MMbbl/year)
- ☐ [Optional] Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); default = 0.27 if measurement data are not available
- ☐ Pressure differential from the previous storage pressure to atmospheric pressure (psi)

For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of CH4 is 0.5 volume percent or more, measure these parameters…

- ☐ Product–specific, vapor-phase CH_4 composition (from measurement data or process knowledge)

See also the information sheet for Petroleum Refineries at:
https://www.epa.gov/ghgreporting/subpart-y-information-sheet

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. This information is intended to assist reporting facilities/owners in understanding key provisions of the Greenhouse Gas Reporting Program.