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waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(2) The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr and either of the following conditions exist:

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe; or

(ii) The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(b) CO₂, CH₄, and N₂O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO₂ emissions from sour gas sent off site for sulfur recovery operations under this subpart. You must follow the calculation methodologies from § 98.253(f) and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart.

(d) CO₂ process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO₂, CH₄, and N₂O emissions from each coke calcining unit under this subpart.

(f) CO₂ and CH₄ emissions from asphalt blowing operations under this subpart.

(g) CH₄ emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO₂, CH₄, and N₂O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO₂ emissions from non-merchant hydrogen production process units (not including hydrogen produced from catalytic reforming units) following the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting require-

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ments, and recordkeeping requirements of subpart P of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79160, Dec. 17, 2010; 78 FR 71963, Nov. 29, 2013]

§ 98.253 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in § 98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (b)(3) of this section.

(1) Calculate the CO₂ emissions according to the applicable requirements in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) *Flow measurement.* If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) *Heat value or carbon content measurement.* If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare using the applicable methods in paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B).

(A) If you monitor gas composition, calculate the CO₂ emissions from the flare using either Equation Y-1a or Equation Y-1b of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-1a or Equation Y-1b of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^n \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad (\text{Eq. Y-1a})$$

where:

CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

44 = Molecular weight of CO₂ (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

(Flare)_p = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare

gas flow rate in kg/period and replace the term "(MW)_p/MVC" with "1".

(MW)_p = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 pounds per square inch absolute (psia) or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

(CC)_p = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

$$CO_2 = \sum_{p=1}^n \left[(Flare)_p \times \frac{44}{MVC} \times 0.001 \times \left(\frac{(\%CO_2)_p}{100\%} + \sum_{x=1}^y \left\{ 0.98 \times \frac{(\%C_x)_p}{100\%} \times CMN_x \right\} \right) \right] \quad (\text{Eq. Y-1b})$$

where:

CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

(Flare)_p = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, you must determine the average molecular weight of the flare gas during the measurement period and convert the mass flow to a volumetric flow.

44 = Molecular weight of CO₂ (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

(%CO₂)_p = Mole percent CO₂ concentration in the flare gas stream during the measure-

ment period (mole percent = percent by volume).

y = Number of carbon-containing compounds other than CO₂ in the flare gas stream.

x = Index for carbon-containing compounds other than CO₂.

0.98 = Assumed combustion efficiency of a flare (mole CO₂ per mole carbon).

(%C_x)_p = Mole percent concentration of compound "x" in the flare gas stream during the measurement period (mole percent = percent by volume)

CMN_x = Carbon mole number of compound "x" in the flare gas stream (mole carbon atoms per mole compound). E.g., CMN for ethane (C₂H₆) is 2; CMN for propane (C₃H₈) is 3.

(B) If you monitor heat content but do not monitor gas composition, calculate the CO₂ emissions from the flare using Equation Y-2 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-2 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^n [(Flare)_p \times (HHV)_p \times EmF] \quad (\text{Eq. Y-2})$$

Where:

CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

(Flare)_p = Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[MMscf] = 0.000001 × Flare[kg] × MVC/(MW)_p, where MVC is the molar volume conversion factor [849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia depending on the standard conditions used when determining (HHV)_p] and (MW)_p is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).

(HHV)_p = Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

EmF = Default CO₂ emission factor of 60 kilograms CO₂/MMBtu (HHV basis).

(iii) *Alternative to heat value or carbon content measurements.* If you do not measure the higher heating value or carbon content of the flare gas at least weekly, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO₂ emissions as specified in paragraphs (b)(1)(iii)(A) through (b)(1)(iii)(C) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event exceeding 500,000 scf/day.

(B) For periods of normal operation, use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculations.

(C) Calculate the CO₂ emissions using Equation Y-3 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum_{p=1}^n \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad (\text{Eq. Y-3})$$

Where:

CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).

Flare_{Norm} = Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).

HHV = Higher heating value for fuel gas or flare gas from company records (British

thermal units per scf, Btu/scf = MMBtu/MMscf).

EmF = Default CO₂ emission factor for flare gas of 60 kilograms CO₂/MMBtu (HHV basis).

n = Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day.

p = Start-up, shutdown, and malfunction event index.

44 = Molecular weight of CO₂ (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

(Flare_{SSM})_p = Volume of flare gas combusted during indexed start-up, shutdown, or

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malfunction event from engineering calculations, (scf/event).
 (MW)_p = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
 MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

(CC)_p = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).

(2) Calculate CH₄ using Equation Y-4 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH_4} \quad (\text{Eq. Y-4})$$

Where:

CH₄ = Annual methane emissions from flared gas (metric tons CH₄/year).
 CO₂ = Emission rate of CO₂ from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).
 EmF_{CH₄} = Default CH₄ emission factor for "Fuel Gas" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH₄/MMBtu).
 EmF = Default CO₂ emission factor for flare gas of 60 kg CO₂/MMBtu (HHV basis).
 0.02/0.98 = Correction factor for flare combustion efficiency.
 16/44 = Correction factor ratio of the molecular weight of CH₄ to CO₂.
 f_{CH₄} = 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); default is 0.4.

(3) Calculate N₂O emissions using Equation Y-5 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N_2O}}{EmF} \right) \quad (\text{Eq. Y-5})$$

Where:

N₂O = Annual nitrous oxide emissions from flared gas (metric tons N₂O/year).
 CO₂ = Emission rate of CO₂ from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).
 EmF_{N₂O} = Default N₂O emission factor for "Fuel Gas" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg N₂O/MMBtu).
 EmF = Default CO₂ emission factor for flare gas of 60 kg CO₂/MMBtu (HHV basis).

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (c)(5) of this section.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate and report CO₂ emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic cracking units and traditional fluid coking units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Combustion Sources), or follow the requirements of paragraphs (c)(2) or (3) of this section.

(i) Calculate CO₂ emissions by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) For catalytic cracking units whose process emissions are discharged through a combined stack with other CO₂ emissions (*e.g.*, co-mingled with emissions from a CO boiler) you must also calculate the other CO₂ emissions using the applicable methods for the applicable subpart (*e.g.*, subpart C of this part in the case of a CO boiler). Calculate the process emissions from the catalytic cracking unit or fluid coking unit as the difference in the CO₂ CEMS emissions and the calculated emissions associated with the additional units discharging through the combined stack.

(2) For catalytic cracking units and fluid coking units with rated capacities greater than 10,000 barrels per stream day (bbls/sd) that do not use a continuous CO₂ CEMS for the final exhaust stack, you must continuously or no

less frequently than hourly monitor the O₂, CO₂, 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 the CO₂ emissions according

to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section:

(i) Calculate the CO₂ emissions from each catalytic cracking unit and fluid coking unit using Equation Y-6 of this section.

$$CO_2 = \sum_{p=1}^n \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right] \quad (\text{Eq. Y-6})$$

Where:

CO₂ = Annual CO₂ mass emissions (metric tons/year).

Q_r = 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 standard cubic feet per hour, dscfh).

%CO₂ = Hourly average percent CO₂ concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).

%CO = 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.

44 = Molecular weight of CO₂ (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

0.001 = Conversion factor (metric ton/kg).

n = Number of hours in calendar year.

(ii) Either continuously monitor the 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 or calculate the volumetric flow rate of this exhaust gas stream using either Equation Y-7a or Equation Y-7b of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. Y-7a})$$

where:

Q_r = 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 (dscfh).

Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).

Q_{oxy} = 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).

%O₂ = Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regen-

erator or fluid coking unit burner (percent by volume—dry basis).

%O_{oxy} = O₂ 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).

%CO₂ = Hourly average percent CO₂ concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).

%CO = 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

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CO monitor is not required under 40 CFR part 63 subpart UUU, assume %CO to be zero.

$$Q_r = \frac{(78.1 * Q_a + (\%N_{2,oxy}) * Q_{oxy})}{\%N_{2,exhaust}} \quad (\text{Eq. Y-7b})$$

where:

Q_r = 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 (dscfh).

Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).

Q_{oxy} = 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).

$\%N_{2,oxy}$ = 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).

$\%N_{2,exhaust}$ = 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).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must 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 of this part.

(3) For catalytic cracking units and fluid coking units with rated capacities of 10,000 barrels per stream day (bbls/sd) or less that do not use a continuous CO_2 CEMS for the final exhaust stack, comply with the requirements in paragraph (c)(3)(i) of this section or paragraphs (c)(3)(ii) and (c)(3)(iii) of this section, as applicable.

(i) If 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 cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, you must calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section, except that daily averages are allowed and the summation can be performed on a daily basis.

(ii) If you do not monitor at least 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, calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y-8 of this section.

$$CO_2 = Q_{unit} \times (CBF \times 0.001) \times CC \times \frac{44}{12} \quad (\text{Eq. Y-8})$$

Where:

CO_2 = Annual CO_2 mass emissions (metric tons/year).

Q_{unit} = Annual throughput of unit from company records (barrels (bbls) per year, bbl/yr).

CBF = Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11.

0.001 = Conversion factor (metric ton/kg).

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CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.

44/12 = Ratio of molecular weight of CO₂ to C (kg CO₂ per kg C).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO₂ emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C of this part (General Stationary Fuel Combustion Sources) and report those emissions by following the requirements of subpart C of this part.

(4) Calculate CH₄ emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-9 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \quad (\text{Eq. Y-9})$$

Where:

CH₄ = Annual methane emissions from coke burn-off (metric tons CH₄/year).

CO₂ = Emission rate of CO₂ from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF₁ = Default CO₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO₂/MMBtu).

EmF₂ = Default CH₄ emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH₄/MMBtu).

(5) Calculate N₂O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-10 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right) \quad (\text{Eq. Y-10})$$

Where:

N₂O = Annual nitrous oxide emissions from coke burn-off (mt N₂O/year).

CO₂ = Emission rate of CO₂ from coke burn-off calculated in paragraphs (c)(1), (c)(2),

(e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF₁ = Default CO₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO₂/MMBtu).

EmF₃ = Default N₂O emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (kg N₂O/MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO₂ emissions using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH₄ and N₂O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO₂ emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic reforming units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (e)(2) or (e)(3) of this section.

(2) If you continuously or no less frequently than daily monitor the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, you must calculate the CO₂ emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO₂ emissions from the catalytic reforming unit catalyst regenerator using Equation Y-11 of this section.

$$CO_2 = \sum_1^n \left[(CB_Q)_n \times CC \times \frac{44}{12} \times 0.001 \right] \quad (\text{Eq. Y-11})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).

CB_Q = Coke burn-off quantity per regeneration cycle or measurement period from engineering estimates (kg coke/cycle or kg coke/measurement period).

n = Number of regeneration cycles or measurement periods in the calendar year.

CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.

44/12 = Ratio of molecular weight of CO₂ to C (kg CO₂ per kg C).

0.001 = Conversion factor (metric ton/kg).

(f) For on-site sulfur recovery plants and for sour gas sent off site for sulfur recovery, calculate and report CO₂ process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section, or, for non-Claus sulfur recovery plants, according to the requirements in paragraph (j) of this section regardless of the concentration of CO₂ in the vented gas stream. Combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part (General Stationary Fuel Combustion Sources). For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(2) through (f)(5) of this section is not considered a fuel.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part, you must calculate CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor 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 and calculate the combustion emis-

sions from the fuel use according to subpart C of this part. Calculate the process emissions from the sulfur recovery plant as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack. Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f)(2) through (f)(5) of this section, or (for non-Claus sulfur recovery plants only) follow the requirements in paragraph (j) of this section to determine CO₂ emissions for the sulfur recovery plant.

(2) Flow measurement. If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant or the sour gas feed sent for off-site sulfur recovery, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant or the sour gas feed sent for off-site sulfur recovery, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(3) Carbon content. If you have a continuous gas composition monitor capable of measuring carbon content on the sour gas feed to the sulfur recovery plant or the sour gas feed sent for off-site for sulfur recovery, or if you monitor gas composition for carbon content on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor using limited measurement data or engineering estimates or use the default factor of 0.20.

(4) Calculate the CO₂ emissions from each on-site sulfur recovery plant and for sour gas sent off-site for sulfur recovery using Equation Y-12 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \quad (\text{Eq. Y-12})$$

Where:

- CO₂ = Annual CO₂ emissions (metric tons/year).
- F_{SG} = Volumetric flow rate of sour gas (including sour water stripper gas) fed to the sulfur recovery plant or the sour gas feed sent off-site for sulfur recovery (scf/year).
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- MF_C = Mole fraction of carbon in the sour gas fed to the sulfur recovery plant or the sour gas feed sent off-site for sulfur recovery (kg-mole C/kg-mole gas); default = 0.20.
- 0.001 = Conversion factor, kg to metric tons.

(5) If tail gas is recycled to the front of the sulfur recovery plant and the recycled flow rate and carbon content is included in the measured data under paragraphs (f)(2) and (f)(3) of this section, respectively, then the annual CO₂ emissions calculated in paragraph (f)(4) of this section must be corrected to avoid double counting these emissions. You may use engineering estimates to perform this correction or assume that the corrected CO₂ emissions are 95 percent of the uncorrected value calculated using Equation Y-12 of this section.

(g) For coke calcining units, calculate GHG emissions according to the

applicable provisions in paragraphs (g)(1) through (g)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part, you must calculate and report CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the coke calcining unit as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the coke calcining unit final exhaust stack. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (g)(2) of this section.

(2) Calculate the CO₂ emissions from the coke calcining unit using Equation Y-13 of this section.

$$CO_2 = \frac{44}{12} * (M_{in} * CC_{GC} - (M_{out} + M_{dust}) * CC_{MPC}) \quad (\text{Eq. Y-13})$$

Where:

- CO₂ = Annual CO₂ emissions (metric tons/year).
- M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).
- CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).
- M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).

M_{dust} = Annual mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year). For coke calcining units that recycle the collected dust, the mass of coke dust removed from the process is the mass of coke dust collected less the mass of coke dust recycled to the process.

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CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).

44 = Molecular weight of CO₂ (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO₂ emissions from the coke calcining unit calculated in paragraphs (g)(1) or (g)(2), as applicable, and calculate CH₄ using the methods described in paragraph (c)(4) of this section and N₂O emissions using the methods described in paragraph (c)(5) of this section.

(h) For asphalt blowing operations, calculate CO₂ and CH₄ emissions according to the requirements in paragraph (j) of this section regardless of the CO₂ and CH₄ concentrations or according to the applicable provisions in paragraphs (h)(1) and (h)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO₂ and CH₄ emissions using Equations Y-14 and Y-15 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB,CO_2}) \quad (\text{Eq. Y-14})$$

Where:

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times \frac{44}{12} \right) \quad (\text{Eq. Y-16a})$$

where:

CO₂ = Annual CO₂ emissions from controlled asphalt blowing (metric tons CO₂/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

$$CO_2 = Q_{AB} \times \left(EF_{AB,CO_2} + 0.98 \times \left[\left(CEF_{AB} \times \frac{44}{12} \right) - EF_{AB,CO_2} \right] \right) \quad (\text{Eq. Y-16b})$$

where:

CO₂ = Annual CO₂ emissions from controlled asphalt blowing (metric tons CO₂/year).

CO₂ = Annual CO₂ emissions from uncontrolled asphalt blowing (metric tons CO₂/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CO₂} = Emission factor for CO₂ from uncontrolled asphalt blowing from facility-specific test data (metric tons CO₂/MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH_4}) \quad (\text{Eq. Y-15})$$

Where:

CH₄ = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH₄/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CH₄} = Emission factor for CH₄ from uncontrolled asphalt blowing from facility-specific test data (metric tons CH₄/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO₂ using either Equation Y-16a or Equation Y-16b of this section and calculate CH₄ emissions using Equation Y-17 of this section, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section or in the stationary combustion unit emissions required under subpart C of this part (General Stationary Fuel Combustion Sources).

CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.

44 = Molecular weight of CO₂ (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

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EF_{AB,CO₂} = Emission factor for CO₂ from uncontrolled asphalt blowing from facility-specific test data (metric tons CO₂/MMbbl asphalt blown); default = 1,100.
 CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test

data (metric tons C/MMbbl asphalt blown); default = 2,750.
 44 = Molecular weight of CO₂ (kg/kg-mole).
 12 = Atomic weight of C (kg/kg-mole).

$$CH_4 = 0.02 \times (Q_{AB} \times EF_{AB,CH_4}) \quad (\text{Eq. Y-17})$$

where:

CH₄ = Annual methane emissions from controlled asphalt blowing (metric tons CH₄/year).
 0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
 Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
 EF_{AB,CH₄} = Emission factor for CH₄ from uncontrolled asphalt blowing from facility-specific test data (metric tons CH₄/MMbbl asphalt blown); default = 580.

(i) For delayed coking units, calculate the CH₄ emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (i)(1) or (i)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph

(i)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (j) of this section to calculate the CH₄ emissions from the depressurization of the coke drum or vessel regardless of the CH₄ concentration and also calculate the CH₄ emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section. If you have coke drums or vessels of different dimensions, use the process vent method in paragraph (j) of this section and Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 14.7)}{14.7} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH_4} \times 0.001 \right) \quad (\text{Eq. Y-18})$$

Where:

CH₄ = Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).
 N = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
 H = Height of coking unit vessel (feet).
 P_{CV} = Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (i)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (pounds per square inch gauge, psig).
 14.7 = Assumed atmospheric pressure (pounds per square inch, psi).
 f_{void} = Volumetric void fraction of coking vessel prior to steaming (cf gas/cf of vessel); default = 0.6.

D = Diameter of coking unit vessel (feet).
 16 = Molecular weight of CH₄ (kg/kg-mole).
 MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
 MF_{CH₄} = Mole fraction of methane in coking vessel gas (kg-mole CH₄/kg-mole gas, wet basis); default value is 0.01.
 0.001 = Conversion factor (metric ton/kg).

(2) Calculate the CH₄ emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke

drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can reasonably be expected to contain greater than 2 percent by volume CO₂ or greater than 0.5 percent by volume of CH₄ or greater than 0.01 percent by volume (100 parts per million) of N₂O, calculate GHG

emissions using Equation Y-19 of this section. You must also use Equation Y-19 of this section to calculate CH₄ emissions for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas, CH₄ emissions if you elected to use the method in paragraph (i)(1) of this section, and CO₂ and/or CH₄ emissions, as applicable, if you elected this method as an alternative to the methods in paragraphs (f), (h), or (k) of this section.

$$E_x = \sum_{p=1}^N \left((VR)_p \times (MF_x)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001 \right) \quad (\text{Eq. Y-19})$$

Where:

E_x = Annual emissions of each GHG from process vent (metric ton/yr).

N = Number of venting events per year.

P = Index of venting events.

(VR)_p = Average volumetric flow rate of process gas during the event (scf per hour) from measurement data, process knowledge, or engineering estimates.

(MF_x)_p = Mole fraction of GHG x in process vent during the event (kg-mol of GHG x/kg-mol vent gas) from measurement data, process knowledge, or engineering estimates.

MW_x = Molecular weight of GHG x (kg/kg-mole); use 44 for CO₂ or N₂O and 16 for CH₄.

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

(VT)_p = Venting time for the event, (hours).

0.001 = Conversion factor (metric ton/kg).

(k) For uncontrolled blowdown systems, you must calculate CH₄ emissions either using the methods for process vents in paragraph (j) of this section regardless of the CH₄ concentration or using Equation Y-20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device are considered to be controlled and are not required to estimate emissions under this paragraph (k).

$$CH_4 = \left(Q_{Ref} \times EF_{BD} \times \frac{16}{MVC} \times 0.001 \right) \quad (\text{Eq. Y-20})$$

Where:

CH₄ = Methane emission rate from blowdown systems (mt CH₄/year).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

EF_{BD} = Methane emission factor for uncontrolled blown systems (scf CH₄/MMbbl); default is 137,000.

16 = Molecular weight of CH₄ (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

0.001 = Conversion factor (metric ton/kg).

(1) For equipment leaks, calculate CH₄ emissions using the method specified in either paragraph (1)(1) or (1)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation Y-21 of this section.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \quad (\text{Eq. Y-21})$$

Where:

CH_4 = Annual methane emissions from equipment leaks (metric tons/year).

N_{CD} = Number of atmospheric crude oil distillation columns at the facility.

N_{PU1} = 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.

N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.

N_{H2} = Total number of hydrogen plants at the facility.

N_{FGS} = Total number of fuel gas systems at the facility.

(m) For storage tanks, except as provided in paragraph (m)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) and (2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-

specific methane composition data (from measurement data or product knowledge) and the emission estimation methods provided in AP 42, Section 7.1 (incorporated by reference, see § 98.7) or estimate CH_4 emissions from storage tanks using Equation Y-22 of this section.

$$CH_4 = (0.1 \times Q_{Ref}) \quad (\text{Eq. Y-22})$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

0.1 = Default emission factor for storage tanks (metric ton CH_4 /MMbbl).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y-23 of this section.

$$CH_4 = (995,000 \times Q_{un} \times \Delta P) \times MF_{CH_4} \times \frac{16}{MVC} \times 0.001 \quad (\text{Eq. Y-23})$$

Where:

CH_4 = Annual methane emissions from storage tanks (metric tons/year).

Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).

ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).

MF_{CH_4} = Average mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tanks from facility measurements (kg-mole CH_4 /kg-mole gas); use 0.27 as a default if measurement data are not available.

995,000 = Correlation Equation factor (scf gas per MMbbl per psi).

16 = Molecular weight of CH_4 (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

0.001 = Conversion factor (metric ton/kg).

(3) You do not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:

(i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

- (iii) Bottoms receivers or sumps;
- (iv) Vessels storing wastewater; or
- (v) Reactor vessels associated with a manufacturing process unit.

(n) For crude oil, intermediate, or product loading operations for which the vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH₄ emissions from loading operations using vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in AP 42, Section 5.2 (incorporated by reference, see § 98.7). For loading operations in which the vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79160, Dec. 17, 2010; 78 FR 71963, Nov. 29, 2013]

§ 98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors that are associated with sources that use a CEMS to measure CO₂ emissions according to subpart C of this part or that are associated with stationary combustion sources must meet the applicable monitoring and QA/QC requirements in § 98.34.

(b) All gas flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than those subject to the requirements in paragraph (a) of this section shall be calibrated according to the procedures specified by the manufacturer, or according to the procedures in the applicable methods specified in paragraphs (c) through (g) of this section. In the case of gas flow meters, all gas flow meters must meet the calibration accuracy requirements in § 98.3(i). All gas flow meters, gas composition monitors, and heating value monitors must be recalibrated at the applicable frequency specified in paragraph (b)(1) or (b)(2) of this section.

(1) You must recalibrate each gas flow meter according to one of the following frequencies. You may recalibrate at the minimum frequency specified by the manufacturer, biennially

(every two years), or at the interval specified by the industry consensus standard practice used.

(2) You must recalibrate each gas composition monitor and heating value monitor according to one of the following frequencies. You may recalibrate at the minimum frequency specified by the manufacturer, annually, or at the interval specified by the industry standard practice used.

(c) For flare or sour gas flow meters and gas flow meters used to comply with the requirements in § 98.253(j), operate, calibrate, and maintain the flow meter according to one of the following. You may use the procedures specified by the flow meter manufacturer, or a method published by a consensus-based standards organization. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293-8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, <http://www.api.org>).

(d) Except as provided in paragraph (g) of this section, determine gas composition and, if required, average molecular weight of the gas using any of the following methods. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented