Appendix A-1. Reporting Thresholds and Reporting Requirements

Subpart	Reporting Threshold	Reporting and Verification
C—General Stationary Combustion	25,000 metric tons C02e/year	See Section 4(b)(i) of the ICR.
D—Electricity Generation (§98.40)	All In	See reporting requirements for general stationary combustion in Section 4(b)(i) of the ICR.
E—Adipic Acid Production (§98.50)	All In	(1) Annual process N2O emissions from adipic acid production (metric tons). (2) Annual adipic acid production (tons). (3) Annual adipic acid production during which N2O abatement technology is operating (tons). (4) Annual process N2O emissions from adipic acid production facility that is sold or transferred off-site (metric tons). (5) Number of abatement technologies (if applicable). (6) Types of abatement technology or technologies used (if applicable). (7) Abatement technology destruction efficiency for each abatement technology (percent destruction). (8) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating). (9) Number of times in the reporting year that missing data procedures were followed to measure adipic acid production (months). **If a performance test and site-specific emissions factors were used:** **(**1) Emissions factor (lb N2O/ton adipic acid). (2) Test method used for performance test. (3) Production rate per test run during performance test (tons/hr). (4) N2O concentration per test run during performance test (ppm N2O). (5) Volumetric flow rate per test run during performance test (dscf/hr). (6) Number of test runs. (7) Number of times in the reporting year that a performance test had to be repeated (number). **If approval was requested for an alternative method of calculating N2O concentration**: (1) Name of alternative method. (2) Description of alternative method. (3) Request date. (4) Approval date.
F—Aluminum Production (§98.60)	All In	(1) Annual aluminum production in metric tons. (2) Type of smelter technology used. (3) The following PFC-specific information on an annual basis: Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electolysis cells combined; Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%)); Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured. (4) Method used to measure the frequency and duration of anode effects (or overvoltage). (5) The following CO2-specific information for prebake cells: Annual anode consumption and annual CO2 emissions from the smelter (6) The following CO2-specific information for Søderberg cells: Annual paste consumption and annual CO2 emissions from the smelter (7) Smelter-specific inputs to the CO2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis. (8) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

Subpart	Reporting Threshold	Reporting and Verification
G—Ammonia Manufacturing (§98.70)	All In	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Annual quantity of each type of feedstock consumed for ammonia manufacturing (scf of feedstock or gallons of feedstock or kg of feedstock). (2) Method used for determining quantity of feedstock used. **If a CEMS is not used to measure emissions**: (1) Annual CO2 process emissions (metric tons) for each ammonia manufacturing process unit. (2) Monthly quantity of each type of feedstock consumed for ammonia manufacturing for each ammonia processing unit (scf of feedstock or gallons of feedstock or kg of feedstock). (3) Method used for determining quantity of monthly feedstock used. (4) Whether carbon content for each feedstock for month n is based on reports from the supplier or analysis of carbon content. (5) If carbon content of feedstock for month n is based on analysis, the test method used. (6) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under 98.74(e) (7) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock). (8) If a facility uses gaseous feedstock, the molecular weight of the gaseous feedstock (kg/kg-mole). (9) If a facility uses gaseous feedstock, the molar volume conversion factor of the gaseous feedstock (scf per kg-mole). (10) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month n, (kg C per gallon of feedstock). (11) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month n, (kg C per kg of feedstock). (12) Annual CO2 emissions associated with the waste recycle stream for each ammonia processing unit (metric tons). (13) Carbon content of the waste recycle stream for month n for each ammonia processing unit (kg C per kg of waste recycle stream). (14) Volume of the waste recycle stream for month n for each ammonia processing unit (scf) (15) Method used for analyzing carbon content of waste recycle stream. (16) Annual urea production (metric tons) and method used to determine urea production. (17) Uses of urea produced, if known, such as but not limited to (fertilizer, animal feed, manufacturing of plastics or resins, pollution control technologies, etc.). **All:** Total pounds of synthetic fertilizer produced through and total nitrogen contained in that fertilizer.
H—Cement Production (§98.80)	All In	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Monthly clinker production from each kiln at the facility. (2) Monthly cement production from each kiln at the facility. (3) Number of kilns and number of operating kilns. **If a CEMS is not used to measure CO2 emissions**: (1) Kiln identification number.. (2) Monthly clinker production from each kiln. (3) Monthly cement production from each kiln. (4) Number of kilns kilns and number of operating kilns. (5) Quarterly quantity of CKD not recycled to the kiln for each kiln at the facility. (6) Monthly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in clinker for each kiln (as wt-fractions). (7) Method used to determine non-calcined CaO and non-calcined MgO in clinker. (8) Quarterly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in CKD not recycled to the kiln for each kiln (as wt-fractions). (9) Method used to determine non-calcined CaO and non-calcined MgO in CKD. (10) Monthly kiln-specific clinker CO2 emission factors for each kiln (metric tons CO2/metric ton clinker produced). (11) Quarterly kiln-specific CKD CO2 emission factors for each kiln (metric tons CO2/metric ton CKD produced). (12) Annual organic carbon content of each raw material (wt-fraction, dry basis). (13) Aannual consumption of each raw material (dry basis). (14) Number of times missing data procedures were used to determine: (i) Clinker production (number of months); (ii) Carbonate contents of clinker (number of months); (iii) Non-calcined content of clinker (number of months); (iv) CKD not recycled to kiln (number of quarters); (v) Non-calcined content of CKD (number of quarters); (vi) Organic carbon contents of raw materials (number of times); and (vii) Raw material consumption (number of months).

Subpart	Reporting Threshold	Reporting and Verification
K—Ferroalloy Production (§98.110)	25,000 metric tons C02e/year	**All**: (1) Total pounds of synthetic fertilizer produced through and total nitrogen contained in that fertilizer. (2) Annual production for each ferroalloy product (tons) identified in §98.110, as applicable. (3) Total number of EAFs at facility used for production of ferroalloy products reported in paragraph (a)(4) of this section. **If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Annual process CO2 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of subpart K. (2) Annual process CH4 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of subpart K (metric tons). (3) Identification each EAF. **If a CEMS is not used to measure CO2 process emissions**,: (1) Annual process CO2 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart (metric tons). (2) Annual process CH4 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart (metric tons). (3) Identification number of each EAF. (4) Annual material quantity for each material included for the calculation of annual process CO2 emissions for each EAF. (5) Annual average of the carbon content determinations for each material included for the calculation of annual process CO2 emissions for each EAF (percent by weight, expressed as a decimal fraction). (6) The method used for the determination of carbon content for each material reported in paragraph (e)(5) of this section (e.g., supplier provided information, analyses of representative samples you collected). (7) For missing data procedures: How monthly mass of carbon-containing inputs and outputs with missing data was determined and the number of months the missing data procedures were used.
N—Glass Production (§98.140)	25,000 metric tons C02e/year	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Annual quantity of each carbonate-based raw material charged to each continuous glass melting furnace and for all furnaces combined (tons). (2) Annual quantity of glass produced (tons). **If a CEMS is not used** to determine CO2 emissions from continuous glass melting furnaces, and process CO2 emissions are calculated according to the procedures specified in §98.143(b): (1) Annual process emissions of CO2 (metric tons) for each continuous glass melting furnace and for all furnaces combined. (2) Annual quantity of each carbonate-based raw material charged (tons) to each continuous glass melting furnace and for all furnaces combined. (3) Annual quantity of glass produced (tons) from each continuous glass melting furnace and from all furnaces combined. (4) Carbonate-based mineral mass fraction (percentage, expressed as a decimal) for each carbonate-based raw material charged to a continuous glass melting furnace. (5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, including (i) Date of test; (ii) Test method(s) and any variations used in the analyses; and (iii) Mass fraction of each sample analyzed; (6) The fraction of calcination achieved (percentage, expressed as a decimal) for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO2. (7) Method used to determine fraction of calcination (percentage, expressed as a decimal). (8) Total number of continuous glass melting furnaces. (9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials for any continuous glass melting furnace or mass fraction of the carbonate-based minerals (months).

Subpart	Reporting Threshold	Reporting and Verification
O—HCFC-22 Production and HFC-23 Destruction (§98.150)	HCFC-22: All In HFC-23 destruction processes that are not collocated with HCFC-22 production and that destroy more than 2.14 metric tons HFC-23 per year: All In	**Production facilities** At the facility level: (1) Annual mass of HCFC-22 produced in metric tons. (2) Annual Loss Factor used to account for the loss of HCFC– 22 upstream of the measurement. (3) Annual mass of reactants fed into the process in metric tons of reactant. (4) The mass (in metric tons) of materials other than HCFC-22 and HFC-23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process. (5) The method for tracking startups, shutdowns, and malfunctions and HFC-23 generation/emissions during these events. (6) The names and addresses of facilities to which any HFC-23 was sent for destruction, and the quantities of HFC-23 (metric tons) sent to each. (7) Annual mass of the HFC-23 generated in metric tons. (8) Annual mass of any HFC-23 sent off site for sale in metric tons. (9) Annual mass of any HFC-23 sent off site for destruction in metric tons. (10) Annual masses of HFC-23 in storage at the beginning and end of the year, in metric tons. (11) Annual mass of HFC-23 emitted in metric tons. (12) Annual mass of HFC-23 emitted from equipment leaks in metric tons. (13) Annual mass of HFC-23 emitted from process vents in metric tons.
		HFC-23 destruction facilities (1) Annual mass of HFC-23 fed into the thermal oxidizer. (2) Annual mass of HFC-23 destroyed. (3) Annual mass of HFC-23 emitted from the thermal oxidizer. Plus the esults of the facility's annual HFC-23 concentration measurements at the outlet of the destruction device, including: (1) The flow rate of HFC-23 being fed into the destruction device in kg/hr. (2) The concentration (mass fraction) of HFC-23 at the outlet of the destruction device. (3) The flow rate at the outlet of the destruction device in kg/hr. (4) The emission rate calculated from (2) and (3) above in kg/hr. Plus a one-time report including the following information: (1) The destruction unit’s destruction efficiency (DE). (2) The methods used to determine the unit’s destruction efficiency. (3) The methods used to record the mass of HFC-23 destroyed. (4) The name of other relevant federal or state regulations that may apply to the destruction process. (5) If any changes are made that affect HFC-23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change.

Subpart	Reporting Threshold	Reporting and Verification
P—Hydrogen Production (§98.160)	25,000 metric tons C02e/year	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Unit identification number and annual CO2 process emissions. (2) Annual quantity of hydrogen produced (metric tons) for each process unit and for all units combined. (3) Annual quantity of ammonia produced (metric tons), if applicable (metric tons) for each process unit and for all units combined. **If a CEMS is not used to measure CO2 emissions**: (1) Unit identification number and annual CO2 process emissions. (2) Monthly consumption of each fuel and feedstock used for hydrogen production and its type (scf of gaseous fuels and feedstocks, gallons of liquid fuels and feedstocks, kg of solid fuels and feedstocks). (3) Annual quantity of hydrogen produced (metric tons). (4) Annual quantity of ammonia produced, if applicable (metric tons). (5) Monthly analyses of carbon content for each fuel and feedstock used in hydrogen production (kg carbon /kg of gaseous and solid fuels and feedstocks, (kg carbon per gallon of liquid fuels and feedstocks). (6) Monthly analyses of the molecular weight of gaseous fuels and feedstocks (kg/kg-mole) used, if any. **All:** (1) Quarterly quantity of CO2 collected and transferred off site in either gas, liquid, or solid forms (kg), following the requirements of subpart PP of this part. (2) Annual quantity of carbon other than CO2 collected and transferred off site in either gas, liquid, or solid forms (kg carbon).
Q—Iron & Steel Production (§98.170)	25,000 metric tons C02e/year	**Each coke pushing operation; taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; argon-oxygen decarburization vessel; and direct reduction furnace:** (1) Unit identification number and annual CO2 emissions (in metric tons) . (2) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel. **If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology **If a CEMS is not used to measure CO2 emissions**: An indication for each of whether for each process whether the emissions were determined using the carbon mass balance method in §98.173(b)(1) or the site-specific emission factor method in §98.173(b)(2). **If the carbon mass balance method is used to determine CO2 emissions**: (1) The carbon content of each process input and output used to determine CO2 emissions. (2) Whether the carbon content was determined from information from the supplier or by laboratory analysis, and if by laboratory analysis, the test method used. (3) The annual volume of gaseous fuel (in standard cubic feet), the annual volume of liquid fuel (in gallons), and the annual mass (in metric tons) of all other process inputs and outputs used to determine CO2 emissions. (4) The molecular weight of gaseous fuels. (5) For the missing data procedures in §98.175(b): How the monthly mass for each process input or output with missing data was determined and the number of months the missing data procedures were used. **If the site-specific emission factor method is used to determine CO2 emissions**: (1) The measured average hourly CO2 emission rate during the test(in metric tons per hour). (2) The average hourly feed or production rate (as applicable) during the test (in metric tons per hour). (3) The site-specific emission factor (in metric tons of CO2 per metric ton of feed or production, as applicable). (4) The annual feed or production rate (as applicable) used to estimate annual CO2 emissions (in metric tons).
R—Lead Production (§98.180)	25,000 metric tons C02e/year	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Identification number of each smelting furnace. (2) Annual lead product production capacity (tons). (3) Annual production for each lead product (tons). (4) Total number of smelting furnaces at facility used for lead production. **If a CEMS is not used to measure CO2 emissions**: (1) Identification number of each smelting furnace. (2) Annual process CO2 emissions (in metric tons) from each smelting furnace as determined by Eq. R-1 of subpart R. (3) Annual lead product production capacity for the facility and each smelting furnace (tons). (4) Annual production for each lead product (tons). (5) Total number of smelting furnaces at facility used for production of lead products reported in (4). (6) Annual material quantity for each material used for the calculation of annual process CO2 emissions using Eq. R-1 of subpart R for each smelting furnace (tons). (7) Annual average of the carbon content determinations for each material used for the calculation of annual process CO2 emissions using Eq. R-1 of subpart R for each smelting furnace. (8) The method used for the determination of carbon content for each material reported in (7) (e.g., supplier provided information, analyses of representative samples). (9) For the missing data procedures in §98.185(b): How the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

Subpart	Reporting Threshold	Reporting and Verification
S—Lime Manufacturing (§98.190)	All In	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Method used to determine the quantity of lime sold. (2) Method used to determine the quantity of lime byproduct/waste sold. (3) Beginning and end of year inventories for each lime product. (4) Beginning and end of year inventories for lime byproducts/wastes. (5) Annual amount of lime byproduct/waste sold, by type (tons). (6) Annual amount of lime product sold, by type (tons). (7) Annual amount of lime byproduct/waste not sold, by type (tons). (8) Annual amount of lime product not sold, by type (tons). **If a CEMS is not used to measure CO2 emissions**: (1) Annual CO2 process emissions from all kilns combined (metric tons). (2) Monthly emission factors for each lime type. (3) Monthly emission factors for each sold byproduct/waste by lime type. (4) Standard method used (ASTM or NLA testing method) to determine chemical compositions of each lime type and lime byproduct/waste type. (5) Monthly results of chemical composition analysis of each lime product and byproduct/waste sold. (6) Annual results of chemical composition analysis of each type of lime byproduct/waste not sold. (7) Method used to determine the quantity of lime sold. (8) Monthly amount of lime product sold, by type (tons). (9) Method used to determine the quantity of lime byproduct/waste sold. (10) Monthly amount of lime byproduct/waste sold, by type (tons). (11) Annual amount of lime byproduct/waste not sold (tons). (12) Monthly mass of each lime type produced (tons). (13) Beginning and end of year inventories for each lime product. (14) Beginning and end of year inventories for lime byproducts/wastes. (15) Annual lime production capacity (tons) per facility. (16) Number of times in the reporting year that missing data procedures were followed to measure lime production (months) or the chemical composition of lime products sold (months). (17) Indicate whether CO2 was used on-site (i.e. for use in a purification process). If CO2 was used on-site, provide: (i) The annual amount of CO2 captured for use in the on-site process; and (ii) The method used to determine the amount of CO2 captured.
U—Misc. Uses of Carbonate (§98.210)	25,000 metric tons C02e/year	(1) Annual CO2 emissions from miscellaneous carbonate use (metric tons). (2) Annual mass of each carbonate type consumed (tons). (3) Measurement method used to determine the mass of carbonate. (4) Method used to calculate emissions. (5) For the calculation method of 40 CFR 98.213(b)(1)(i): (i) Annual carbonate consumption by carbonate type (tons); (ii) Annual calcination fractions used in calculations; (iii) The standard method was used to determine the calcinations fraction, if applicable. (6) For the calculation method of 40 CFR 98.213(b)(1)(ii): (i) Annual carbonate input by carbonate type (tons) and (ii) Annual carbonate output by carbonate type (tons). (7) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

Subpart	Reporting Threshold	Reporting and Verification
V—Nitric Acid Production (§98.220)	All In	For each nitric acid production train, respondents must report annual N_2O process emissions and: (1) Train identification number. (2) Annual process N2O emissions from each nitric acid train (metric tons). (3) Annual nitric acid production from each nitric acid train (tons, 100 percent acid basis). (4) Annual nitric acid production from each nitric acid train during which N2O abatement technology is operating (ton acid produced, 100 percent acid basis) (5) Annual nitric acid production from the nitric acid facility (tons, 100 percent acid basis). (6) Number of nitric acid trains. (7) Number of abatement technologies (if applicable). (8) Abatement technologies used (if applicable). (9) Abatement technology destruction efficiency for each abatement technology (percent destruction). (10) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating). (11) Type of nitric acid process used for each nitric acid train (single pressure or dual pressure). (12) Number of times in the reporting year that missing data procedures were followed to measure nitric acid production (months). (13) If a performance test was conducted and site-specific emissions factor was calculated: (i) Emission factor calculated for each nitric acid train (lb N2O/ ton nitric acid, 100 percent acid basis); (ii) Test method used for performance test; (iii) Production rate per test run during performance test (tons nitric acid produced/hr, 100 percent acid basis); (iv) N2O concentration per test run during performance test (ppm N2O); (v) Volumetric flow rate per test run during performance test (dscf/hr); (vi) Number of test runs during performance test; (vii) Number of times in the reporting year that a performance test had to be repeated (number). (14) If approval was requested for an alternative method of determining N2O concentration under §98.223(a)(2),: (i) Name of alternative method; (ii) Description of alternative method; (iii) Request date; and (iv) Approval date. (15) Total pounds of synthetic fertilizer produced through and total nitrogen contained in that fertilizer.
X—Petrochemical Production (§98.240)	All In	**For mass balance :** For each process unit: (1) The petrochemical process unit ID number or other appropriate descriptor. (2) The type of petrochemical produced, names of other products, and names of carbon-containing feedstocks. (3) Annual CO2 emissions calculated using Equation X-4 of subpart X. (4) Each of the monthly volume, mass, and carbon content values used in Equations X-1 through X-3 (i.e., the directly measured values, substitute values, or the calculated values based on other measured data such as tank levels or gas composition) and the molecular weights for gaseous feedstocks and products used in Equation X-1. Plus an indication of whether alternative sampling analysis was used. (5) Annual quantity of each type of petrochemical produced from each process unit (metric tons). (6) Name of each method listed in §98.244 used to determine a measured parameter (or description of manufacturer's recommended method). (7) The dates and summarized results (e.g., percent calibration error) of the calibrations of each measurement device. (8) Identification of each combustion unit that burned both process off-gas and supplemental fuel. (9) For the alternative to sampling and analysis: The amount of time during which off-specification product was produced, the volume or mass of off-specification product produced, and if applicable, the date of any process change that reduced the composition to less than 99.5 percent. (10) Respondents may elect to report the flow and carbon content of wastewater and the carbon content of hydrocarbons in fugitive emissions and in process vents that are not controlled with a combustion device. These values may be estimated based on engineering analyses. These values are not to be used in the mass balance calculation. **If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) The petrochemical process unit ID or other appropriate descriptor, and the type of petrochemical produced. (2) The combined CO2 emissions from all stacks (except flare stacks) that handle process vent emissions and emissions from stationary combustion units that burn process off-gas for the petrochemical process unit. If a stationary combustion source serves multiple petrochemical process units or units other than the petrochemical process unit, estimate based on engineering judgment the fraction of fuel energy and emissions attributable to each petrochemical process unit. (3) The combined CH4 and N20 emissions from all stationary combustion units that burn process off-gas from the petrochemical process unit and the annual fuel flow value(s) used in Equation C-9 in §98.33(c). (4) ID or other appropriate descriptor of each stationary combustion unit that burns process off-gas. (5) Information listed in §98.256(e) for each flare that burns process off-gas. (6) Annual quantity of each type of petrochemical produced from each process unit (metric tons). **For the combustion methodology (§98.243(d)):** (1) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), the relevant information listed in §98.36 for the selected Tier 3 or Tier 4 methodology. If a stationary combustion source serves multiple ethylene process units or units other than the ethylene process unit, estimate based on engineering judgment the fraction of fuel energy and emissions attributable to each ethylene process unit. (2) Information listed in §98.256(e) for each flare that burns ethylene process off-gas. (3) Name and annual quantity of each feedstock. (4) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

Subpart	Reporting Threshold	Reporting and Verification
Y—Petroleum Refineries (§98.250)	All In	**Combustion Sources:** See reporting requirements for general stationary combustion in Section 4(b)(i) of the ICR.
		Hydrogen plants : See reporting requirements for hydrogen production (subpart P).
		Flares: (1) The flare ID number (if applicable). (2) A description of the type of flare (steam assisted, air-assisted). (3) A description of the flare service (general facility flare, unit flare, emergency only or back-up flare). (4) The calculated CO2, CH4, and N2O annual emissions for each flare, expressed in metric tons of each pollutant emitted. (5) A description of the method used to calculate the CO2 emissions for each flare (e.g., reference regulatory section and Equation number). (6) If Equation Y-1 of subpart Y was used: The annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole) and carbon content of the flare gas (in kg carbon per kg flare gas). (7) If Equation Y-2 of subpart Y was used: The annual volume of flare gas combusted (in million (MM) scf/year) and the annual average higher heating value of the flare gas (in MMBtu per MMscf). (8) If Equation Y-3 of subpart Y was used: The annual volume of flare gas combusted during normal operations (in MMscf/year), the annual average higher heating value of the flare gas (in MMBtu/MMscf), the number of SSM events exceeding 500,000 scf/day, and the volume of gas flared (in scf/event) and the average molecular weight (in kg/kg-mole) and carbon content of the flare gas in kg carbon per kg flare) for each SSM event over 500,000 scf/day. (9) The fraction of carbon in the flare gas contributed by methane used in Equation Y-4 of subpart Y and the basis for its value.
		For catalytic cracking units, traditional fluid coking units, and catalytic reforming units: (1) The unit ID number (if applicable). (2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit). (3) Maximum rated throughput of the unit, in bbl/stream day. (4) The calculated CO2, CH4, and N2O annual emissions for each unit, expressed in metric tons of each pollutant emitted. (5) A description of the method used to calculate the CO2 emissions for each unit (e.g., reference regulatory section and Equation number). (6) If a CEMS was used: the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO2 annual emissions as measured by the CEMS (unadjusted to remove CO2 combustion emissions associated with a CO boiler, if present) and the process CO2 emissions as calculated according to §98.253(c)(1)(ii). Respondents must report the CO2 annual emissions associated with fuel combustion under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources). (7) If Equation Y-6 of subpart Y was used: The annual average exhaust gas flow rate, %CO2, and %CO. (8) If Equation Y-7 of subpart Y was used: The annual average flow rate of inlet air and oxygen-enriched air, %O2, %Ooxy, %CO2, and %CO. (9) If Equation Y-8 of subpart Y was used: The coke burn-off factor, annual throughput of unit, and the average carbon content of coke and the basis for the value. (10) An indication of whether a measured value, a unit-specific emission factor, or default emission factor was used for CH4 emissions. If unit-specific emission factors for CH4 are used, respondents must report the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor. (11) An indication of whether a measured value, a unit-specific emission factor, or default emission factor was used for N20 emissions. If a unit-specific emission factor was used: The units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor. (12) If Equation Y-11 of subpart Y was used: The number of regeneration cycles during the reporting year, the average coke burn-off quantity per cycle, and the average carbon content of the coke.
		Fluid coking unit of the flexicoking type: (1) The unit ID number (if applicable). (2) A description of the type of unit. (3) Maximum rated throughput of the unit, in bbl/stream day. (4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or §98.253(c). (5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit: The calculated annual CO2, CH4, and N2O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in (7) through (11) above.

Subpart	Reporting Threshold	Reporting and Verification
Y—Petroleum Refineries (§98.250) (continued)	All in	**For sulfur recovery plants and emissions from sour gas sent off-site for sulfur recovery:** (1) The plant ID number (if applicable). (2) Maximum rated throughput of each independent sulfur recovery plant, in metric tons sulfur produced/stream day. (3) The calculated CO2 annual emissions for each sulfur recovery plant, expressed in metric tons. Plus The calculated annual CO2 emissions from sour gas sent off-site for sulfur recovery, expressed in metric tons. (4) If Equation Y-12 of subpart Y was used: The annual volumetric flow (in scf/year to the sulfur recovery plant and the annual average mole fraction of carbon in the sour gas (in kg-mole C/kg-mole gas). (5) If tail gas is recycled to the front of the sulfur recovery plant: An indication of whether the recycled flow rate and carbon content are included in the measured data under §98.253(f)(2) and (3). Also an indication of whether a correction for CO2 emissions in the tail gas was used in Equation Y-12. If so, then respondents must report the value of the correction, the annual volume of recycled tail gas (in scf/year) and the annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas). Respondents must also indicate whether they used the default (95%) or a unit specific correction, and if used, report the approach used. (6) For a CEMS: the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology, the CO2 annual emissions as measured by the CEMS and the annual process CO2 emissions calculated according to §98.253(f)(1). Plus the CO2 annual emissions associated with the process emissions calculated according to §98.253(f)(1). Plus the CO2 annual emissions associated with fuel combustion under 40 CFR 98, subpart C.
		For coke calcining units: (1) The unit ID number (if applicable). (2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day. (3) The calculated CO2, CH4, and N2O annual emissions for each unit, expressed in metric tons of each pollutant emitted. (4) A description of the method used to calculate the CO2 emissions for each unit (e.g., reference regulatory section and Equation number). (5) If Equation Y-13 of subpart Y is used: Annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, and the annual mass of coke dust collected in dust collection systems. (6) If a CEMS is used: The CO2 annual emissions associated with the process emissions calculated according to §98.253(g)(1) plus the CO2 annual emissions associated with fuel combustion under 40 CFR 98, subpart C. (7) An indication of whether a measured value, a unit-specific emission factor or a default for CH4 emissions. If unit-specific emission factor for CH4, is used: the unit-specific emission factor for CH4, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor. (8) If a site-specific emission factor for Equation Y-10 of subpart Y is used: The site-specific emission factor and the basis of the factor.
		For asphalt blowing operations: (1) The unit ID number (if applicable). (2) The quantity of asphalt blown (in Million bbl) at the facility in the reporting year. (3) The type of control device used to reduce methane (and other organic) emissions from the unit. (4) The calculated annual CO2 and CH4 emissions for each unit, expressed in metric tons of each pollutant emitted. (5) If Equation Y-14 of subpart Y is used: The CO2 emission factor used and the basis for the value. (6) If Equation Y-15 of subpart Y is used: The CH4 emission factor used and the basis for the value. (7) If If Equation Y-16 of subpart Y is used: The carbon emission factor used and the basis for the value. (8) If Equation Y-17 of subpart Y is used: The CH4 emission factor used and the basis for the value.
		For delayed coking units: **(**1) The cumulative annual CH4 emissions (in metric tons of each pollutant emitted) for all delayed coking units at the facility. (2) A description of the method used to calculate the CH4 emissions for each unit (e.g., reference regulatory section and Equation number). (3) The total number of delayed coking units at the facility, the total number of delayed coking drums at the facility, and for each coke drum or vessel: the dimensions, the typical gauge pressure of the coking drum when first vented to the atmosphere, typical void fraction, the typical drum outage (i.e. the unfilled distance from the top of the drum, in feet), and annual number of coke-cutting cycles. (4) For each set of coking drums that are the same dimensions: the number of coking drums in the set, the height and diameter of the coke drums (in feet), the cumulative number of vessel openings for all delayed coking drums in the set, the typical venting pressure (in psig), void fraction (in cf gas/cf of vessel), and the mole fraction of methane in coking gas (in kg-mole CF4/kg-mole gas, wet basis). (5) The basis for the volumetric void fraction of the coke vessel prior to steaming and the basis for the mole fraction of methane in the coking gas.
		For process vents subject to §98.253(j): (1) The vent ID number (if applicable). (2) The unit or operation associated with the emissions. (3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable. (4) The calculated annual CO2, CH4, and N2O emissions for each vent, expressed in metric tons of each pollutant emitted. (5) The annual volumetric flow discharged to the atmosphere (in scf), mole fraction of each GHG above the concentration threshold, and for intermittent vents, the number of venting events and the cumulative venting time.

Subpart	Reporting Threshold	Reporting and Verification
Y—Petroleum Refineries (§98.250) (continued)	All in	**For uncontrolled blowdown systems:** (1) The cumulative annual CH4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems. (2) The total quantity (in Million bbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year. (3) The methane emission factor used for uncontrolled blowdown systems and the basis for the value.
		For equipment leaks: **(**1) The cumulative CH4 emissions (in metric tons of each pollutant emitted) for all equipment leak sources. (2) The method used to calculate the reported equipment leak emissions. (3) The number of each type of emission source listed in Equation Y-21 at the facility.
		For storage tanks: (1) The cumulative annual CH4 emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil. (2) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (AP-42, TANKS 4.09D, Equation Y-22 of subpart Y, other). (3) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year. (4) The cumulative CH4 emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil. (5) The method used to calculate the reported storage tank emissions for storage tanks processing unstabilized crude oil. (6) The quantity of unstabilized crude oil received during the calendar year (in MMbbl), the average pressure differential (in psi), the mole fraction of CH4 in vent gas from the unstabilized crude oil storage tank, and the basis for the mole fraction. (7) The tank-specific methane composition data and the gas generation rate data, if you did not use Equation Y-23.
		For loading operations: (1) The cumulative annual CH4 emissions (in metric tons of each pollutant emitted) for loading operations. (2) The quantity and types of materials loaded by vessel type (barge, tanker, marine vessel, etc.) that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded. (3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any (submerged loading, vapor balancing, etc.).
		For all: Name of each method listed in §98.254 (or a description of the manufacturer's recommended method) used determine a measured parameter.

Subpart	Reporting Threshold	Reporting and Verification
Z—Phosphoric Acid Production (§98.260)	All In	**All:** (1) Annual phosphoric acid production by origin (as listed in Table Z-1 to subpart Z) of the phosphate rock (tons). (2) Annual phosphoric acid permitted production capacity (tons). (3) Annual arithmetic average percent inorganic carbon in phosphate rock from monthly records. (4) Annual phosphate rock consumption from monthly measurement records by origin (as listed in Table Z-1 to subpart Z) from monthly measurement records (tons). **If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) The identification number of each wet-process phosphoric acid process line. (2) The annual CO2 emissions from each wet-process phosphoric acid process line (metric tons) and the relevant information required under 40 CFR 98.36 (e)(2)(vi) for the Tier 4 Calculation Methodology. **If a CEMS is not used to measure CO2 emissions:** (1) Identification number of each wet-process phosphoric acid process line. (2) Annual CO2 emissions from each wet-process phosphoric acid process line (metric tons) as calculated by Eq. Z-1 of subpart Z. (3) Annual phosphoric acid permitted production capacity for each wet-process phosphoric acid process line (metric tons). (4) Method used to estimate any missing values of inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line. (5) Monthly inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line (percent by weight, expressed as a decimal fraction). (6) Monthly mass of phosphate rock consumed by origin, (as listed in Table Z-1 to subpart Z) in production for each wet-process phosphoric acid process line (tons). (7) Number of wet-process phosphoric acid process lines. (8) Number of times missing data procedures were used to estimate phosphate rock consumption (months) and inorganic carbon contents of the phosphate rock (months).
AA—Pulp and Paper Manufacturing (§98.270)	25,000 metric tons C02e/year	(1) Annual emissions of CO2, biogenic CO2, CH4, biogenic CH4 N2O, and biogenic N2O (metric tons per year). (2) Annual quantities fossil fuels by type used in chemical recovery furnaces and chemical recovery combustion units in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels. (3) Annual mass of the spent liquor solids combusted (short tons per year), and basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI or an online measurement system). (4) The high heat value (HHV) of the spent liquor solids used in equation AA-1 of subpart AA (mmBtu per kilogram). (5) The default emission factor for CO2, CH4, or N2O, used in Equation AA-1 of this subpart (kg CO2, CH4, or N2O per mmBtu). (6) The carbon content (CC) of the spent liquor solids, used in equation AA-2 of subpart AA (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). (7) Annual quantities of fossil fuels by type used in pulp mill lime kilns in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels. (8) Make-up quantity of CaCO3 used for the reporting year (metric tons per year) used in equation AA-3 of subpart AA. (9) Make-up quantity of Na2CO3 used for the reporting year (metric tons per year) used in equation AA-3 of subpart AA. (10) Annual steam purchases(pounds of steam per year). (11) Annual production of pulp and/or paper products produced (metric tons).
BB—Silicon Carbide Production (§98.280)	All In	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Annual consumption of petroleum coke (tons). (2) Annual production of silicon carbide (tons). (3) Annual production capacity of silicon carbide (tons). **If a CEMS is not used to measure process CO2 emissions:** (1) Monthly consumption of petroleum coke (tons). (2) Annual production of silicon carbide (tons). (3) Annual production capacity of silicon carbide (tons). (4) Carbon content factor of petroleum coke from the supplier or as measured by the applicable method in 98.284(c) for each month (percent by weight expressed as a decimal fraction). (5) Whether carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM Standard Test Method. (6) CO2 emissions factor calculated for each month (metric tons CO2/metric ton of petroleum coke consumed). (7) Sampling analysis results for carbon content of consumed petroleum coke as determined for QA/QC of supplier data under 98.284(d) (percent by weight expressed as a decimal fraction). (8) Number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months) and petroleum coke consumption (number of months).

Subpart	Reporting Threshold	Reporting and Verification
CC—Soda Ash Manufacturing (§98.290)	All in	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (metric tons). (2) Annual production of soda ash for each manufacturing line (tons). (3) Annual production capacity of soda ash for each manufacturing line (tons). (4) Identification number of each manufacturing line. **If a CEMS is not used to measure CO2 emissions**: (1) Annual process CO2 emissions from each soda ash manufacturing line (metric tons). (2) Annual process CO2 emissions from each soda ash manufacturing line (metric tons). (3) Annual production of soda ash (tons). (4) Annual production capacity of soda ash for each manufacturing line (tons). (5) Monthly consumption of trona or liquid alkaline feedstock for each manufacturing line (tons). (6) Monthly production of soda ash (metric tons). (7) Inorganic carbon content factor of trona or soda ash (depending on use of Eq. CC-1 or CC-2) as measured by the applicable method in 98.294(b) or (c) for each month (percent by weight expressed as a decimal fraction). (8) Whether CO2 emissions for each manufacturing line were calculated using a trona input method as described in Equation CC-1, a soda ash output method as described in Equation CC-2, or a site-specific emission factor method as described in Equations CC-3 through CC-5. (9) Number of manufacturing lines located used to produce soda ash. (10) For soda ash produced using the liquid alkaline feedstock process, if the site-specific emission factor method is used to estimate emissions: (i) Stack gas volumetric flow rate per minute (dscfm); (ii) Hourly CO2 concentration (percent CO2); (iii) CO2 emission factor (metric tons CO2/metric tons of process vent flow from mine water stripper/evaporator); (iv) CO2 mass emission rate (metric tons/hour); (v) Average process vent flow from mine water stripper/evaporater during performance test (pounds/hour); (vi) Annual process vent flow rate from mine stripper/evaporator (thousand pounds/hour); and (vii) Annual operating hours for each manufacturing line used to produce soda ash using liquid alkaline feedstock (hours). (11) Number of times missing data procedures were used and for which of the following parameters: (i) Trona or soda ash (number of months); (ii) Inorganic carbon contents of trona or soda ash (weeks); (iii) Process vent flow rate from mine water stripper/evaporator (number of months); (iv) Stack gas volumetric flow rate during performance test(number of times);(v) Hourly CO2 concentration (number of times); or (vi) Average vent process vent flow rate from mine stripper/evaporator during performance test (number of times).
EE—Titanium Dioxide Production (§98.310)	All In	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Identification number of each process line. (2) Annual consumption of calcined petroleum coke (tons). (3) Annual production of titanium dioxide (tons). (4) Annual production capacity of titanium dioxide (tones). (5) Annual production of carbon-containing waste (tons), if applicable. **If a CEMS is not used to measure CO2 emissions:** (1) Identification number of each process line. (2) Annual CO2 emissions from each chloride process line (metric tons/year). (3) Annual consumption of calcined petroleum coke for each process line (tons). (4) Annual production of titanium dioxide for each process line (tons). (5) Annual production capacity of titanium dioxide for each process line (tons). (6) Calcined petroleum coke consumption for each process line for each month (tons). (7) Annual production of carbon-containing waste for each process line (tons), if applicable. (8) Monthly production of titanium dioxide for each process line (tons). (9) Monthly carbon content factor of petroleum coke from the supplier (percent by weight expressed as a decimal fraction). (10) Whether monthly carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM Standard Test Methods. (11) Carbon content for carbon-containing waste (percent by weight expressed as a decimal fraction). (12) If carbon content of petroleum coke is based on self measurement, the ASTM Standard Test Methods used. (13) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under 98.314(d) (percent by weight expressed as a decimal fraction). (14) Number of separate chloride process lines located at the facility. (15) The number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months); petroleum coke consumption (number of months); carbon-containing waste generated (number of months); and carbon contents of the carbon-containing waste (number of times during year).

Subpart	Reporting Threshold	Reporting and Verification
GG—Zinc Production (§98.330)	25,000 metric tons C02e/year	**If a CEMS is used to measure CO2 emissions:** All relevant information required under 40 CFR 98.37(e)(2)(vi) for the Tier 4 Calculation Methodology plus: (1) Annual zinc product production capacity (tons). (2) Annual production quantity for each zinc product (tons). (3) Annual facility production quantity for each zinc product (tons). (4) Number of Waelz kilns at each facility used for zinc production. (5) Number of electrothermic furnaces at each facility used for zinc production. **If a CEMS is not used to measure CO2 emissions:** (1) Kiln identification number and annual process CO2 emissions from each individual Waelz kiln or electrothermic furnace (metric tons). (2) Annual zinc product production capacity (tons). (3) Annual production quantity for each zinc product (tons). (4) Number of Waelz kilns at each facility used for zinc production. (5) Number of electrothermic furnaces at each facility used for zinc production. (6) Annual mass of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials (e.g., limestone, dolomite), carbon electrode, and other carbonaceous materials (e.g., coal, coke) (tons). (7) Carbon content of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials, and other carbonaceous materials) from the annual carbon analysis for each kiln or furnace (percent by weight, expressed as a decimal fraction). (8) Whether carbon content of each carbon-containing input material charged to each kiln or furnace is based on reports from the supplier or through self measurement using applicable ASTM Standard Test Method. (9) If carbon content of each carbon-containing input material charged to each kiln or furnace is based on self measurement, the ASTM Standard Test Method used. (10) Carbon content of the carbon electrode used in each furnace from the annual carbon analysis (percent by weight, expressed as a decimal fraction). (11) Whether carbon content of the carbon electrode used in each furnace is based on reports from the supplier or through self measurement using applicable ASTM Standard Test Method. (12) If carbon content of carbon electrode used in each furnace is based on self measurement, the ASTM Standard Test Method used. (13) For the missing data procedures in §98.335(b): How the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

Subpart	Reporting Threshold	Reporting and Verification
HH—Landfills (§98.340)	25,000 metric tons C02e/year	(1) A classification of the landfill as "open" (actively received waste in the reporting year) or "closed" (no longer receiving waste), the year in which the landfill first started accepting waste for disposal, the last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure), the capacity (in metric tons) of the landfill, an indication of whether leachate recirculation is used, and the waste disposal quantity for each year of landfilling. (2) Method for estimating waste disposal quantity, and reason for its selection. (3) Waste composition for each year of landfilling, if available, in percentage categorized as (a) Municipal. (b) Biosolids or biological sludges; (c) Other, or more refined categories, such as those for which k rates are available in Table HH-1 of this subpart, and the method or basis for estimating waste composition. (4) For each waste type used to calculate CH4 generation using Equation HH-1 of subpart H: (i) Degradable organic carbon (DOC) value used and (ii) Decay rate (k) value used. (5) Fraction of CH4 in landfill gas (F) and an indication of whether the fraction of CH4 was determined based on measured values or the default value. (6) The surface area of the landfill containing waste (in square meters), the cover types applicable to the landfill, the surface area and oxidation fraction for each cover type used to calculate the average oxidation fraction, and the average oxidation fraction used in the calculations. (7) The modeled annual methane generation rate for the reporting year (metric tons CH4) calculated using Equation HH-1 of subpart HH. (8) For landfills without gas collection systems, the annual methane emissions (i.e., the methane generation, adjusted for oxidation, calculated using Equation HH-5 of subpart HH), reported in metric tons CH4. For landfills with gas collection systems: (1) Total volumetric flow of landfill gas collected for destruction (cubic feet at 520°R or 60°F and 1 atm). (2) CH4 concentration of landfill gas collected for destruction (percent by volume). (3) Monthly average temperature for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature is incorporated into internal calcuations run by the monitoring equipment. (4) Monthly average pressure for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature is incorporated into internal calcuations run by the monitoring equipment. (5) An indication of whether destruction occurs at the landfill facility or off-site. If destruction occurs at the landfill facility: An indication of whether a back-up destruction device is present at the landfill, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), and the destruction efficiency used (percent). (6) Annual quantity of recovered CH4 (metric tons CH4) calculated using Equation HH-4 of subpart HH. (7) A description of the gas collection system (manufacture, capacity, number of number of wells, etc.), the surface area (square meters) and estimated waste depth (meters) for each area specified in Table HH-3 of subpart HH, the estimated gas collection system efficiency for landfills with this gas collection system, and the annual operating hours of the gas collection system. (8) Methane generation corrected for oxidation calculated using Equation HH-5 of subpart HH, reported in metric tons CH4; (9) Methane generation (GCH4) value used as an input to HH-6. Specify whether the value is modeled (GCH4 from HH-1) or measured (R from Eq. HH-4) (10) Methane generation corrected for oxidation calculated using Equation HH-7 of subpart HH, reported in metric tons CH4. (11) Methane emissions calculated using Equation HH-6 of subpart HH, reported in metric tons CH4; and (12) Methane emissions calculated using Equation HH-8 of subpart HH, reported in metric tons CH4.

Subpart	Reporting Threshold	Reporting and Verification
JJ—Manure Management (§98.360)	25,000 metric tons C02e/year	(1) List of manure management system component(s) at the facility. (2) Fraction of manure from each animal type that is handled in each manure management system component. (3) Average annual animal population (for each animal type) for static populations or the results of Equation JJ-4 for growing populations. (4) Average number of days that growing animals are kept at the facility (for each animal type). (5) The number of animals produced annually for growing populations (for each animal type). (6) Typical animal mass (for each animal type). (7) Total facility emissions (results of Equation JJ-14). (8) CH4 emissions from manure management system components listed in §98.360(b), except digesters (results of Equation JJ-2). (9) VS value(s) used (for each animal type). (10) B0 value(s) used (for each animal type). (11) Methane conversion factor(s) used (for each MMS component). (12) Average ambient temperature used to select ach methane conversion factor. (13) N2O emissions (results of Equation JJ-13). (14) N value(s) used for each animal type. (15) N2O emission factor selected for each MMS component.
		Facilities with anaerobic digesters must also report: (1) CH4 emissions from anaerobic digesters (results of Equation JJ-5) (2) CH4 flow to the digester combustion device (for each digester) (results of Equation JJ-6, or value from fully integrated monitoring system as described in 98.363(b)) (3) CH4 destruction for each digester (results of Equation JJ-11) (4) CH4 leakage for each digester (results of Equation JJ-12) (5) Annual volumetric biogas flow for each digester (results of Equation JJ-7). (6) Average annual CH4 concentration for each digester (results of Equation JJ-8). (7) Average annual temperature at which gas flow is measured for each digester (results of Equation JJ-9). (8) Average annual gas flow pressure at which gas flow is measured for each digester (results of Equation JJ-10). (9) Destruction efficiency used for each digester. (10) The number of days per year that the digester was operating for each digester. (11) The collection efficiency used for each digester.

Subpart	Reporting Threshold	Reporting and Verification
LL—Suppliers of Coal-based Liquid Fuels (§98.380)	Producers of coal-to-liquid products: All in Importers & Exporters: 25,000 metric tons C02e/year	**Producers (for each coal-to-liquid facility):** (1) For each product listed in table MM-1 that enters the coal-to-liquid facility to be further processed or otherwise used on site: The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (2) For each product listed in table MM-1 that enters the coal-to-liquid facility to be further processed or otherwise used on site: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product. (3) For each feedstock reported in (2) that was produced by blending a fossil fuel-based product with a biomass-based product: The percent of the volume reported in (2) that is fossil fuel-based. (4) Each standard method or other industry standard practice used to measure each quantity reported in (1). (5) For each product (leaving the coal-to-liquid facility) listed in table MM-1: The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (6) For each product (leaving the coal-to-liquid facility) listed in table MM-1: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product. (7) For each product reported in (6) that was produced by blending a fossil fuel-based product with a biomass-based product: The percent of the volume reported in (6) that is fossil fuel-based. (8) Each standard method or other industry standard practice used to measure each quantity reported in (5). (9) For every feedstock reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The number of samples collected according to §98.394(c); (ii) The sampling standard method used; (iii) The carbon share test results in percent mass; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons. (10) For every non-solid feedstock reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The density test results in metric tons per barrel and (ii) The standard method used to test density. (11) For every product reported in (6) for which Calculation Method 2 was used to determine an emissions factor: (i) The number of samples collected according to §98.394(c); (ii) The sampling standard method used; (iii) The carbon share test results in percent mass; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons. (12) For every non-solid product reported in (6) for which Calculation Method 2 was used to determine an emissions factor: (i) The density test results in metric tons per barrel and (ii) The standard method used to test density; (13) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in (6): The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. (14) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in (6): The annual quantity in metric tons or barrels. (15) Each standard method or other industry standard practice used to measure each quantity reported in (12). (16) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in (2), calculated according to §98.393(b) or (h). (17) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each product (leaving the coal-to-liquid facility) reported in (6), calculated according to §98.393(a) or (h). (18) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with fossil fuel-based feedstocks reported in (12), calculated according to §98.393(c). (19) The total sum of CO2 emissions that would result from the complete combustion or oxidation of all products, calculated according to §98.393(d). (20) The total quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.
		Importers: (1) For each product listed in table MM-1 of subpart M: The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (2) For each product listed in table MM-1 of subpart M: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product as listed in table MM-1. (3) For each product reported in (2) that was produced by blending a fossil fuel-based product with a biomass-based product: The percent of the volume reported in (2) that is fossil fuel-based. (4) Each standard method or other industry standard practice used to measure each quantity reported in (1). (5) For each product reported in (2) for which Calculation Method 2 used was used to determine an emissions factor: (i) The number of samples collected according to §98.394(c); (ii) The sampling standard method used; (iii) The carbon share test results in percent mass; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons. (6) For each non-solid product reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The density test results in metric tons per barrel and (ii) The standard method used to test density. (7) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each imported product reported in (2), calculated according to §98.393(a). (8) The total sum of CO2 emissions that would result from the complete combustion or oxidation of all imported products.

Subpart	Reporting Threshold	Reporting and Verification
LL—Suppliers of Coal-based Liquid Fuels (§98.380) (continued)	Producers of coal-to-liquid products: All in Importers & Exporters: 25,000 metric tons C02e/year	**Exporters:** (1) For each product listed in table MM-1: The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (2) For each product listed in table MM-1: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product. (3) For each product reported in (2) that was produced by blending a fossil fuel-based product with a biomass-based product: The percent of the volume reported in (2) that is fossil fuel-based. (4) Each standard method or other industry standard practice used to measure each quantity reported in (1). (5) For each product reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The number of samples collected according to §98.394(c); (ii) The sampling standard method used; (iii) The carbon share test results in percent mass; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons. (6) For each non-solid product reported in (2) for which Calculation Method 2 used was used to determine an emissions factor: (i) The density test results in metric tons per barrel and (ii) The standard method used to test density; (7) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each exported product reported in (2), calculated according to §98.393(a). (8) Total sum of CO2 emissions that would result from the complete combustion or oxidation of all exported products, calculated according to §98.393(e).
MM—Suppliers of Petroleum Products (§98.390)	Refiners: All in Importers & Exporters: 25,000 metric tons C02e/year	**Refiners:** (1) For each petroleum product or natural gas liquid listed in table MM-1 that enters the refinery as a feedstock to be further refined or otherwise used on site: The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (2) For each petroleum product or natural gas liquid listed in table MM-1 that enters the refinery to be further refined or otherwise used on site: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product. (3) For each feedstock reported in (2) that was produced by blending a petroleum-based product with a biomass-based product: The percent of the volume reported in (2) that is petroleum-based. (4) Each standard method or other industry standard practice used to measure each quantity reported in (1). (5) For each petroleum product and natural gas liquid (ex refinery gate) listed in table MM-1: The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (6) For each petroleum product and natural gas liquid (ex refinery gate) listed in table MM-1 of subpart MM: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product. (7) For each product reported in (6) that was produced by blending a petroleum-based product with a biomass-based product: The percent of the volume reported in (6) that is petroleum-based. (8) Each standard method or other industry standard practice used to measure each quantity reported in (5). (9) For every feedstock reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The number of samples collected; (ii) The sampling standard method used; (iii) The carbon share test results in percent mass; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons. (10) For every non-solid feedstock reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The carbon share test results in percent mass and (ii) The standard method used to test density/ (11) For every petroleum product and natural gas liquid reported in (6) for which Calculation Method 2 was used to determine an emissions factor: (i) The number of samples collected; (ii) The sampling standard method used; (iii) The density test results in metric tons per barrel; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons CO2 per barrel or per metric ton of product. (12) For every non-solid petroleum product and natural gas liquid reported in paragraph (a)(6) for which Calculation Method 2 was used to determine an emissions factor: (i) The density test results in metric tons per barrel and (ii) The standard method used to test density. (13) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in (6): The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. (14) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in (6): The annual quantity in metric tons or barrels. (15) Each standard method or other industry standard practice used to measure each quantity reported (13). (16) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid (ex refinery gate) reported in (6). (17) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in (2). (18) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum feedstocks reported in (12). (19) The sum of CO2 emissions that would result from the complete combustion or oxidation of all products. (20) All of the following information for all crude oil feedstocks used at the refinery: (i) Batch volume in barrels; (ii) API gravity of the batch at the point of entry at the refinery; (iii) Sulfur content of the batch at the point of entry at the refinery; and (iv) Country of origin of the batch, if known. (21) The quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

Subpart	Reporting Threshold	Reporting and Verification
MM—Suppliers of Petroleum Products (§98.390) (continued)	25,000 metric tons C02e/year	**Importers:** (1) For each petroleum product and natural gas liquid listed in table MM-1: The annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (2) For each petroleum product and natural gas liquid listed in table MM-1: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product as listed in table MM-1 of subpart MM. (3) For each product reported in (2) that was produced by blending a petroleum-based product with a biomass-based product: The percent of the volume reported in (2) that is petroleum-based. (4) Each standard method or other industry standard practice used to measure each quantity reported in (1). (5) For each product reported in (2) for which Calculation Method 2 used was used to determine an emissions factor:: (i) The number of samples collected according to §98.394(c); (ii) The sampling standard method used; (iii) The carbon share test results in percent mass; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons CO2 per barrel or per metric ton of product. (6) For each non-solid product reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The density test results in metric tons per barrel and (ii) The standard method used to test density. (7) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each imported petroleum product and natural gas liquid reported in (2), calculated according to §98.393(a). (8) The sum of CO2 emissions that would result from the complete combustion or oxidation of all imported products, calculated according to §98.393(e).
		Exporters: (1) For each petroleum product and natural gas liquid listed in table MM-1 of subpart MM: The annual quantity in metric tons or barrels by quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity must reflect the individual components of the product. (2) For each petroleum product and natural gas liquid listed in table MM-1 of subpart MM: The annual quantity in metric tons or barrels. For natural gas liquids, quantity must reflect the individual components of the product. (3) For each product reported in (2) that was produced by blending a petroleum-based product with a biomass-based product: The percent of the volume reported in (2) that is petroleum based. (4) Each standard method or other industry standard practice used to measure each quantity reported in (1). (5) For each product reported in (2) for which Calculation Method 2 was used to determine an emissions factor: (i) The number of samples collected according to §98.394(c); (ii) The sampling standard method used; (iii) The carbon share test results in percentmass; (iv) The standard method used to test carbon share; and (v) The calculated CO2 emissions factor in metric tons CO2 per barrel or per metric ton of product. (6) For each non-solid product reported in (2) for which Calculation Method 2 used was used to determine an emissions factor: (i) The density test results in metric tons per barrel and (ii) The standard method used to test density. (7) The CO2 emissions in metric tons that would result from the complete combustion or oxidation of each exported petroleum product and natural gas liquid reported in (2), calculated according to §98.393(a). (8) The sum of CO2 emissions that would result from the complete combustion or oxidation of all exported products, calculated according to §98.393(e).

Subpart	Reporting Threshold	Reporting and Verification
NN—Suppliers of Natural Gas and Natural Gas Liquids (§98.400)	All In	**NGL fractionator:** (1) Annual quantity (in barrels) of each NGL product supplied to downstream facilities in the following categories: ethane, propane, normal butane, isobutane, and pentanes plus. (2) Annual quantity (in barrels) of each NGL product received from other NGL fractionators in the following categories: ethane, propane, normal butane, isobutane, and pentanes plus. (3) Annual volumes in Mscf of natural gas received for processing. (4) Annual quantity (in barrels) of y-grade, bulk NGLs received from others for fractionation. (5) Annual quantity (in barrels) of propane that the NGL fractionator odorizes at the facility and delivers to others. (6) Annual CO2 emissions (in metric tons) that would result from the complete combustion or oxidation of the volumes in (1) and (2). (7) Annual CO2 mass emissions (metric tons) that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received by other fractionators, calculated in accordance with §98.403(c)(2). (8) The specific industry standard used to measure the quantities reported in (1). (9) If the LNG fractionator developed reporter-specific EFs or HHVs: (i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404 (b)(2) and (c)(3); (ii) The developed HHV(s); and (iii) The developed EF(s).
		Local distribution companies: (1) Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC. (2) Annual volume in Mscf of natural gas placed into storage. (3) Annual volume in Mscf of vaporized liquefied natural gas (LNG) produced at on-system vaporization facilities for delivery on the distribution system that is not accounted for in (1). (4) Annual volume in Mscf of natural gas withdrawn from on-system storage (that is not delivered to the city gate) for delivery to on the distribution system. (5) Annual volume in Mscf of natural gas delivered directly to LDC systems from producers or natural gas processing plants from local production. (6) Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies. (7) Annual volume in Mscf of natural gas delivered by LDC to each meter registering supply equal to or greater than 460,000 Mcsf during the calendar year. (8) Annual CO2 mass emissions (metric tons) associated with the volumes in (1) - (7) and calculated in accordance with §98.403. (9) Annual CO2 emissions (metric tons) that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users registering less than 460,000 Mcsf, calculated in accordance with §98.403(b)(4). (10) The specific industry standard used to develop the volume reported in (1). (11) If the LDC developed reporter-specific EFs or HHVs: (i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404 (b)(2) and (c)(3); (ii) The developed HHV(s); and (iii) The developed EF(s). (12) The customer name, address, and meter number of each meter reading used to report in (7). If known, the EIA identification number of each LDC customer. (13) The annual volume in Mscf of natural gas delivered by the local distribution company to each of the following end-use categories: (i) Residential consumers; (ii) Commercial consumers; (iii) Industrial consumers; and (iv) Electricity generating facilities.
		All: Each reporter must report the number of days in the reporting year that substitute data procedures were used for the following purpose: (i) To measure quantity; (ii) To develop HHV(s); and (iii) To develop EF(s).

Subpart	Reporting Threshold	Reporting and Verification
OO—Suppliers of Industrial Greenhouse Gases (§98.410)	Producers: All in Importers & Exporters: 25,000 metric tons C02e/year	**Fluorinated GHG or nitrous oxide production facility:** (1) Mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility by process, except for amounts that are captured solely to be shipped off site for destruction. (2) Mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility, by process. (3) Mass in metric tons of each fluorinated GHG destroyed at that facility, except fluorinated GHGs that are not included in the calculation of the mass produced in 40 CFR 98.413(a) because they are removed from the production process as by-products or other wastes. Quantities could include, for example, quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed. (4) Mass in metric tons of each fluorinated GHG that is destroyed at that facility except GHGs not included in the calculation of mass produced in 40 CFR 98.413(a) because it is removed from the production process as a byproduct or other waste. (5) Total mass in metric tons of each fluorinated GHG or nitrous oxide sent to another facility for transformation. (6) Total mass in metric tons of each fluorinated GHG sent to another facility for destruction, except fluorinated GHGs that are not included in the mass produced in 40 CFR 98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported could include, for example, fluorinated GHGs that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore sent to another facility for destruction. (7) Total mass in metric tons of each fluorinated GHG that is sent to another facility for destruction and that is not included in the mass produced in 40 CFR 98.413(a) because it is removed from the production process as a byproduct or other waste. (8) Total mass in metric tons of each reactant fed into the F-GHG or nitrous oxide production process, by process. (9) Total mass in metric tons of the reactants, by-products, and other wastes permanently removed from the F-GHG or nitrous oxide production process, by process. (10) For transformation processes that do not produce an F-GHG or nitrous oxide, mass in metric tons of any fluorinated GHG or nitrous oxide fed into the transformation process, by process. (11) Mass in metric tons of each fluorinated GHG fed into the destruction device. (12) Mass in metric tons of each fluorinated GHG or nitrous oxide that is measured coming out of the production process, by process. (13) Mass in metric tons of each used fluorinated GHGs or nitrous oxide added back into the production process (e.g., for reclamation), including returned heels in containers that are weighed to measure the mass in 98.414(a), by process. (14) Names and addresses of facilities to which any nitrous oxide or fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation. (15) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for destruction. (16) Where missing data have been estimated pursuant to §98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.
		Fluorinated GHG production facilities that destroy fluorinated GHGs (one-time report): (1) Destruction efficiency (DE) of each destruction unit. (2) Test methods used to determine the destruction efficiency. (3) Methods used to record the mass of fluorinated GHG destroyed. (4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE. (5) Name of all applicable federal or state regulations that may apply to the destruction process. (6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.
		Bulk importer of fluorinated GHGs or N_2O: For each import (except for shipments including less than 250 metric tons of CO2e, transshipments, and heels that meet the conditions set forth at 98.417(e)): (1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk. (2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical. (3) Date on which the fluorinated GHGs or nitrous oxide were imported. (4) Port of entry through which the fluorinated GHGs or nitrous oxide passed. (5) Country from which the imported fluorinated GHGs or nitrous oxide were imported. (6) Commodity code of the fluorinated GHGs or nitrous oxide shipped. (7) Importer number for the shipment. (8) Total mass in metric tons of each fluorinated GHG destroyed by the importer. (9) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for transformation. (10) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for destruction.

Subpart	Reporting Threshold	Reporting and Verification
OO—Suppliers of Industrial Greenhouse Gases (§98.410) (cont'd)	25,000 metric tons C02e/year	**Bulk exporter of fluorinated GHGs or N_2O:** For each export (except for shipments including less than 250 metric tons of CO2e, transshipments, and heels): (1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk. (2) Names and addresses of the exporter and the recipient of the exports. (3) Exporter's Employee Identification Number. (4) Commodity code of the fluorinated GHGs and nitrous oxide shipped. (5) Date on which, and the port from which, fluorinated GHGs and nitrous oxide were exported from the United States or its territories. (6) Country to which the fluorinated GHGs or nitrous oxide were exported.
		By April 1, 2011, a fluorinated GHG production facility must submit a one-time report describing: (1) The method(s) by which the producer in practice measures the mass of fluorinated GHGs produced, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision. (2) The method(s) by which the producer in practice estimates the mass of fluorinated GHGs fed into the transformation process, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision. (3) The method(s) by which the producer in practice estimates the fraction of fluorinated GHGs fed into the transformation process that is actually transformed, and the estimated precision and accuracy of this estimate. (4) The method(s) by which the producer in practice estimates the masses of fluorinated GHGs fed into the destruction device, including the method(s) used to estimate the concentration of the fluorinated GHGs in the destroyed material, and the estimated precision and accuracy of this estimate. (5) The estimated percent efficiency of each production process for the fluorinated GHG produced.
PP—Suppliers of Carbon Dioxide (CO_2) (§98.420)	Producers: All in Bulk importers & exporters: 25,000 metric tons C02e/year	**Facilities that use Equation PP-1 of 40 CFR 98.423:** For each mass flow meter: (1) Annual mass in metric tons of the CO2 stream captured, extracted, or transferred in either gas or liquid solid forms for the purposes of supplying CO2 for commercial applications or in order to sequester or otherwise inject it underground when custody of the CO2 is maintained. Of this quantity, each reporter must report the aggregated annual quantity of CO2 in metric tons that is transferred to each of the following end use applications, if known: (i) Food and beverage; (ii) Industrial and municipal water/wastewater treatment; (iii) Metal fabrication, including welding and cutting; (iv) Greenhouse uses for plant growth; (v) Fumigants (e.g., grain storage) and herbicides; (vi) Pulp and paper; (vii) Cleaning and solvent use; (viii) Fire fighting; (ix) Transportation and storage of explosives; (x) Enhanced oil and natural gas recovery; (xi) Long-term storage (sequestration); (xii) Research and development; (xiii) Other. (2) Quarterly mass flow of the CO2 stream captured, extracted, or transferred in either gas, liquid, or solid forms in metric tons per quarter. (3) Quarterly concentration of the CO2 stream captured, extracted, or transferred in either gas, liquid, or solid forms. Plus the standard used to measure CO2 concentration.
		Facilities that use Equation PP-2 of 40 CFR 98.423: For each volumetric flow meter: (1) Annual mass in metric tons of the CO2 stream captured, extracted, or transferred in either gas, liquid, or solid forms for the purposes of suppling CO2 for commercial applications or in order to sequester or otherwise inject it underground when custody of the CO2 is maintained. (2) Quarterly volumetric flow of the CO2 stream captured, extracted, or transferred in either gas, liquid, or solid forms in standard cubic meters per quarter. (3) Quarterly concentration of the CO2 stream captured, extracted, or transferred in either gas or liquid forms. (4) Quarterly density of the CO2 stream captured, extracted, or transferred in either gas or liquid forms in metric tons per standard cubic meter. (5) The method used to measure density. Plus the standard used to measure CO2 concentration.
		Facilities that use Equation PP-3 of 40 CFR 98.423: (1) Annual CO2 mass supplied in metric tons from all flow meters from facility wells or production process units.
		Facilities that use Equation PP-4 of 40 CFR 98.423: 1) Annual mass of carbon dioxide in metric tons in all CO2 containers imported or exported based on mass measurements. CO2 importers and exporters must report the information in (1) and (2) at the corporate level.
		All: (1) The type of equipment used to measure the total flow of the CO2 stream or the total mass in CO2 containers. (2) The standard used to operate and calibrate the equipment reported in (1). CO2 importers and exporters must report the information in (1) and (2) at the corporate level. Plus: (j) Each reporter must report the number of days in the reporting year for which substitute data procedures were used for the following purposes: (i) To measure quantity; (ii) To measure concentration; and (iii) To measure density.

Note: Many facilities that would be affected by the rule emit GHGs from multiple sources. The facility must assess every source category that could potentially apply to each when determining if a threshold has been exceeded. If the threshold is exceed for any source category, the facility must report emissions from all source categories, including those source categories that do not exceed the applicable threshold.