Chapter 173-441 WAC

REPORTING EMISSIONS OF GREENHOUSE GASES

NEW SECTION

WAC 173-441-010 Purpose. The purpose of this rule is to develop a comprehensive inventory of greenhouse gas emissions in Washington state by establishing a reporting system for emissions of greenhouse gases, as required in chapter 70.94 RCW. An inventory of greenhouse gas emissions will support the legislature's intent to limit and reduce emissions of greenhouse gases consistent with the emissions reductions requirements established in RCW 70.235.020.

NEW SECTION

WAC 173-441-020 Consistency with federal regulations. Should the federal government adopt rules sufficient to track progress toward the emissions reductions required by RCW 70.235.020, the department must amend this chapter, as necessary, to seek consistency with the federal rules to ensure duplicate reporting is not required. It is the department's intent that the reporting requirements of this chapter be consistent with any federal greenhouse gas emission reporting requirements to the extent required by RCW 70.94.151.

NEW SECTION

WAC 173-441-030 Definitions. The definitions in this section apply throughout this chapter unless the context clearly requires otherwise:

"Activity data" means information collected and used to calculate greenhouse gas emissions. Examples include but are not limited to: Fuel use, fuel properties, electricity consumption, mileage, location, duration of operation, and number of emission units.

"Aircraft" means any vehicle for transporting people or cargo by air, including, but not limited to, airplanes, helicopters, and airships. Any mobile equipment carried on or moved by aircraft and capable of emitting greenhouse gases while in transit, including but not limited to: Air conditioning units, refrigeration units, and auxiliary power units, is considered to be part of the aircraft.

"Auxiliary power unit" means equipment carried on or moved by a mobile source whose purpose is to provide energy during locomotion for functions other than propulsion.

"Biomass" means plants or parts of plants, animal waste, or any product made of either of these, and includes wood and wood products, agricultural residues and wastes, biologically derived organic matter found in municipal and industrial wastes, landfill gas, bioalcohols, spent pulping liquor, sludge gas, and animal- or plant-derived oils, and fuels derived from biomass.

"Capital lease" means a lease that transfers substantially all the risks and rewards of ownership to the lessee and is accounted for as an asset on the balance sheet of the lessee, as described in the Statement of Financial Accounting Standards 13, Accounting for Leases, issued November 1976. Also known as a finance lease or financial lease.

"Carbon dioxide equivalents" or "CO_2e" means a metric measure used to compare the emissions from various greenhouse gases based upon their global warming potential.

"Certification" or "certify" means a written and signed certification statement by the designated representative that, based on information and belief formed after reasonable inquiry, the reported emissions are true, accurate, complete, free of material misstatement, and comply with the requirements of this chapter.

"Department" means department of ecology.

"Designated representative" means the person authorized by the reporter of an emissions source to represent and legally bind the reporter and to be responsible for certifying and submitting greenhouse gas emissions reports under this chapter. The designated representative must be an individual having responsibility for the overall operation of the emissions source such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

"Direct emissions" means emissions of greenhouse gases from sources of emissions, including stationary combustion sources, mobile combustion emissions, process emissions, and fugitive emissions.

"Emissions report" or "greenhouse gas emissions report" means the report of total emissions of greenhouse gases prepared by the reporter each year and submitted electronically to the department to meet the reporting requirements of this chapter.

"Finance lease" means the same as capital lease.

"Fleet of aircraft" means a collection of all aircraft operating in Washington state with a common owner or operator. Aircraft that operate exclusively within the boundaries of a specific site are considered part of the emissions from that site and not part of the fleet of aircraft.

"Fleet of marine vessels" means a collection of all marine vessels operating in Washington state with a common owner or operator. Marine vessels that operate exclusively within the boundaries of a specific site are considered part of the emissions from that site and not part of the fleet of marine vessels.

"Fleet of nonroad mobile sources" means a collection of each fleet of aircraft, fleet of marine vessels, and fleet of rail equipment operating in Washington state used for the transportation of people or cargo with a common owner or operator. Aircraft and marine vessels that operate exclusively within the boundaries of a specific site are considered part of the emissions from that site and not part of the fleet of nonroad mobile sources.

"Fleet of on-road motor vehicles" means a collection of all on-road motor vehicles operating in Washington state with a common owner or operator. On-road motor vehicles that operate exclusively within the boundaries of a specific site are considered part of the emissions from that site and not part of the fleet of on-road motor vehicles.

"Fleet of rail equipment" means a collection of all rail equipment operating in Washington state with a common owner or operator. All rail equipment operating in Washington state, including rail equipment operating exclusively in a single rail yard or other restricted location, is considered part of the fleet of rail equipment instead of being part of a site.

"Fugitive emissions" means emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

"Global warming potential" or "GWP" means the ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given greenhouse gas compared to one unit of carbon dioxide (CO_2). See Tables 100.2 and 100.3 in WAC 173-441-100(6).

"Greenhouse gas" and "greenhouse gases" includes carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

"Hydrofluorocarbons" or "HFCs" means a class of greenhouse gases primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

"Intergovernmental Panel on Climate Change" or "IPCC" means the scientific intergovernmental body set up by the World Meteorological Organization (WMO) and by the United Nations Environment Programme (UNEP).

"Indirect emissions" means emissions of greenhouse gases associated with the purchase of electricity, heating, cooling, or steam.

"Marine vessel" means any vessel for transporting people or cargo by sea or freshwater, including, but not limited to, tugboats and cargo, passenger, fishing, military, personal, and special purpose ships and boats. Any mobile equipment carried on or moved by a marine vessel and capable of emitting greenhouse gases while in transit, including, but not limited to, air conditioning units, refrigeration units, and auxiliary power units, is considered to be part of the marine vessel.

"Material misstatement" means one or more inaccuracies identified during the certification process that result in the total emissions of greenhouse gases reported being outside the ninety-five percent accuracy required under this chapter. The ninety-five percent accuracy in total emissions of greenhouse gases reported is required for all reporters.

"Mobile source" means any on-road motor vehicle, aircraft, marine vessel, or rail equipment used for the transportation of people or cargo.

"Nonroad mobile source" means any aircraft, marine vessel, or rail equipment used for the transportation of people or cargo.

"On-road motor vehicles" means any self-propelled vehicle required to be licensed for operation on the roads of Washington state. Any mobile equipment carried on or moved by an on-road motor vehicle and capable of emitting greenhouse gases while in transit, including, but not limited to, air conditioning units, refrigeration units, and auxiliary power units, is considered to be part of the on-road motor vehicle.

"Operating lease" means a lease that does not transfer the risks and rewards of ownership to the lessee and is not recorded as an asset in the balance sheet of the lessee as described in the Statement of Financial Accounting Standards 13, Accounting for Leases, issued November 1976.

"Operational control" means the authority to introduce and implement operating, environmental, health, and safety policies. When this authority is shared, the holder of the business license to operate the site, fleet of on-road motor vehicles, or fleet of nonroad mobile sources is considered to have operational control.

"Owner or operator" means any person who owns, leases, operates, controls, or supervises a source of emissions, as defined in this chapter.

"Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

"Process emissions" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

"Rail equipment" means mobile equipment operating on a track, including, but not limited to: Locomotives, multiple units, railcars, rolling stock, railroad cars, and refrigerator cars. Any mobile equipment carried on or moved by rail equipment and capable of emitting greenhouse gases while in transit, including, but not limited to, air conditioning units, refrigeration units, and auxiliary power units, is considered to be part of the rail equipment.

"Reporter" means the owner or operator of an emissions source responsible for submitting an emissions report under the requirements of this chapter.

"Site" means all sources of emissions located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right of way, under common operational control and having the same first two digits of the Standard Industrial Classification (SIC) or same first three digits of the North American Industry Classification System (NAICS) code. Operators of military installations may classify such installations as more than a single site based on distinct and independent functional groupings within contiguous or adjacent military properties. Unless listed below, emissions from all mobile sources that operate exclusively within the boundaries of a site are part of that site. The following systems are considered a single site:

(a) All of an owner or operator's transmission or distribution pipelines and associated emitting units in Washington state are considered a single site;

(b) All of an owner or operator's electric transmission and distribution lines, substations, switch yards, and associated equipment in Washington state are considered a single site; and

(c) All rail equipment, including rail equipment operating exclusively in a single rail yard or other restricted location, is part of the fleet of rail equipment and not part of a site.

"Source" or "emissions source" or "source of emissions" means:

(a) Any stationary source of greenhouse gas emissions; or

(b) Any mobile source of greenhouse gas emissions that is used for the transportation of people or cargo.

"Stationary source" means any building, structure, facility, or installation that emits or may emit greenhouse gases.

"The Climate Registry" or "TCR" means the 501(c)3 nonprofit organization incorporated in Washington, D.C., March 14, 2007, with the purpose of setting consistent and transparent standards to calculate, verify and publicly report greenhouse gas emissions in North America.

"Tier" means an emission quantification method designated as acceptable in WAC 173-441-100, 173-441-110, or 173-441-500 through 173-441-800, or through petition according to WAC 173-441-120. Simplified estimation methods as described in WAC 173-441-130 are not considered tiered methods. If multiple tiers of emission quantification methods are available for a source or greenhouse gas, then the tiers are ranked alphabetically in order of preference from highest to lowest. If available, "Tier A" designates the preferred, or highest tier; "Tier B" represents an alternative second-highest tier; and "Tier C" represents the least preferred, or lowest tier. All methods adopted through the petition process in WAC 173-441-120 are designated as "Tier D" methods. In some cases there may be multiple tiers for a given source or greenhouse gas with the same letter designation (such as A1 and A2). Tiers with the same letter designation are considered equivalently ranked for the given source or greenhouse gas.

Note: Emission quantification methods described in IPCC documents use a numerical tier classification system that ranks the tiers from lowest to highest (example: Tier 3 is designated as preferred or higher than Tier 1).

"Total emissions of greenhouse gases" means all direct emissions and all indirect emissions.

"Transportation of people or cargo" or "transporting people or cargo" means movement of one or more people and/or raw or processed materials or commercial goods.

"Unified Business Identifier number" means a unique number that is assigned to a business by the Corporations Division of the Washington secretary of state or from the Washington state department of licensing.

"Waters of the state" means all of the lakes, rivers, ponds, streams, inland waters, harbors, salt waters, and all other surface waters and watercourses within the jurisdiction of the state of Washington, including coastal waters within three nautical miles seaward of the mean low-water mark of the coast of Washington.

NEW SECTION

WAC 173-441-040 Applicability. (1) **Reporting thresholds.** Chapter 173-441 WAC reporting requirements apply to:

(a) **Source or combination of sources of emissions.** The owner or operator of a source or combination of sources of emissions located in Washington state that has combined direct emissions from all sites and fleets of nonroad mobile sources of at least ten thousand metric tons of greenhouse gases in a calendar year, expressed as CO_2e; provided, that the phasing provisions in WAC 173-441-060 apply to the reporting of emissions occurring during 2009, 2010, and 2011; and

(b) **Fleet of on-road motor vehicles.** The owner or operator of a fleet of on-road motor vehicles that has direct emissions of at least two thousand five hundred metric tons of greenhouse gases in a calendar year in Washington state, expressed as CO_2e. The reporting threshold for emissions from fleets of on-road motor vehicles is not phased in and emissions must be reported according to subsection (2)(c) of this section for 2009 emissions reported in 2010 and subsequent years.

(2) **Meeting reporting thresholds.** An owner or operator must use the process established below to determine if the direct emissions meet the applicable reporting threshold.

(a) **Reporting emissions from intrastate, interstate, and international travel.** When determining if the direct emissions meet the applicable thresholds in subsection (1)(a) or (b) of this section, the owner or operator must include the direct emissions generated in Washington state from intrastate, interstate, and international mobile sources.

(b) **Source or combination of sources of emissions.** An owner or operator of a source or combination of sources of emissions must determine if its direct emissions meet the reporting threshold established in subsection (1)(a) of this section using the following methods:

(i) **Quantification methods.** An owner or operator of a source or combination of sources of emissions within Washington state must use the methods in WAC 173-441-100 when determining if direct emissions of greenhouse gases from these sources of emissions meet the applicable CO_2e annual reporting threshold.

(ii) **Mobile sources.** An owner or operator must include emissions from nonroad mobile sources when applying the CO_2e annual reporting threshold, including, but not limited to, emissions from its: Fleet of aircraft, fleet of marine vessels, fleet of rail equipment, and mobile sources that operate exclusively within the boundaries of a single site. An owner or operator must not include emissions from its fleet of on-road motor vehicles that operate beyond the boundaries of a single site when applying the CO_2e annual reporting threshold.

(iii) **Reporting emissions from intrastate, interstate, and international nonroad mobile sources.** An owner or operator must use the methods in WAC 173-441-080 to determine which emissions are generated within Washington state from intrastate, interstate, and international mobile sources when determining if a fleet of nonroad mobile sources meets the reporting threshold established in subsection (1)(a) of this section.

(iv) **Reporting total emissions of greenhouse gases.** Once an owner or operator determines that the direct emissions meet the reporting threshold for a source or combination of sources of emissions, the owner or operator must report the total emissions of greenhouse gases from those sources including direct emissions from fleets of on-road motor vehicles.

(c) **Fleet of on-road motor vehicles.** An owner or operator of a fleet of on-road motor vehicles must determine if the direct emissions meet the reporting threshold established in subsection (1)(b) of this section using the following methods:

(i) **Quantification methods.** An owner or operator of a fleet of on-road motor vehicles must use the methods in WAC 173-441-110 when determining if direct emissions of greenhouse gases from a fleet of on-road motor vehicles meet the two thousand five hundred metric tons of CO_2e annual reporting threshold.

(ii) **Aggregation of on-road motor vehicles.** An owner or operator of a fleet of on-road motor vehicles must combine the direct emissions of greenhouse gases from all on-road motor vehicles that operate beyond the boundaries of a single site when determining if the fleet of on-road motor vehicles meets the two thousand five hundred metric tons of CO_2e reporting threshold.

(iii) **Reporting emissions from intrastate, interstate, and international on-road motor vehicles.** An owner or operator must use the methods in WAC 173-441-080(2) to determine which emissions are generated within Washington state from intrastate, interstate, and international on-road motor vehicles when determining if a fleet of on-road motor vehicles meets the two thousand five hundred metric tons of CO_2e reporting threshold.

(iv) **Reporting emissions of greenhouse gases.** If direct emissions generated in Washington state from a fleet of on-road motor vehicles meet the two thousand five hundred metric tons of CO_2e annual reporting threshold, the direct emissions of greenhouse gases generated in Washington state from the fleet must be reported.

NEW SECTION

WAC 173-441-050 Reporting responsibility. The owner or operator with operational control of an emissions source during the reporting period is the reporter and is responsible for submitting an emissions report under the requirements of this chapter. For the purposes of this rule, an owner or operator meeting one or more of the following conditions is deemed to have operational control of the emissions source:

(1) **Operational control and shared authority.** The owner or operator has operational control if it has the authority to introduce and implement operating, environmental, health, and safety policies. If this authority is shared between two or more owners or operators, the holder of the business license to operate the site, fleet of on-road motor vehicles, or fleet of nonroad mobile sources is considered to have operational control.

(2) **Leased sources of emissions.** Under a capital, finance, or operating lease, the lessee of an emissions source has operational control and is responsible for reporting the emissions.

(3) **Short term rentals.** For purposes of this chapter, leases or rental agreements of less than one year duration are considered short term rentals. Under a short term rental, the owner or operator of the rental company has operational control and is responsible for reporting emissions from the emissions source.

NEW SECTION

WAC 173-441-060 Phasing in the applicability of the reporting requirements for a source or combination of sources of emissions. The applicability of the reporting threshold for a source or combination of sources of emissions subject to the reporting threshold in WAC 173-441-040 (1)(a), is phased in as specified below. Refer to Table 060.1 of this section for a summary of the phasing schedule established in this section.

(1) **Phasing not applicable for fleets of on-road motor vehicles.** The reporting threshold for emissions from fleets of on-road motor vehicles is not phased in and emissions must be reported according to WAC 173-441-040 (2)(c) for 2009 emissions reported in 2010 and subsequent years.

(2) **Reporting 2009 emissions in 2010.** The thresholds and reporting requirements for 2009 emissions reported in 2010 are specified below. Refer to Figure 060.1 of this section for a flow chart of how to apply the reporting thresholds for 2009 emissions reported in 2010.

(a) **Reporting threshold for 2009 emissions reported in 2010.** For 2009 emissions reported in 2010, the reporting threshold for sources other than fleets of on-road motor vehicles is twenty-five thousand metric tons of direct emissions, expressed as CO_2e.

(b) **Threshold determination for 2009 emissions reported in 2010.** When determining whether the reporting threshold in (a) of this subsection is met, an owner or operator with multiple sites or fleets of nonroad mobile sources within Washington state must calculate the direct emissions for each site and fleet of nonroad mobile sources separately. Each site or fleet of nonroad mobile sources that has direct emissions of at least twenty-five thousand metric tons of CO_2e is subject to the reporting requirements of this chapter. For 2009 emissions reported in 2010, an owner or operator is not required to report emissions from a site or fleet of nonroad mobile sources with direct emissions less than twenty-five thousand metric tons of CO_2e.

(i) **Sites.** For 2009 emissions reported in 2010, when determining whether the direct emissions of a site meet the twenty-five thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from any source or combination of sources located on the site, including all mobile sources that operate exclusively within the boundaries of the site.

(ii) **Fleet of marine vessels.** For 2009 emissions reported in 2010, when determining whether the direct emissions of a fleet of marine vessels meet the twenty-five thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from all marine vessels operating in Washington state beyond the boundaries of a single site.

(iii) **Fleet of rail equipment.** For 2009 emissions reported in 2010, when determining whether the direct emissions of a fleet of rail equipment meet the twenty-five thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from all rail equipment operating in Washington state.

(iv) **Fleet of aircraft.** For 2009 emissions reported in 2010, emissions from intrastate, interstate, and international fleets of aircraft are not required to be reported.

(v) **Intrastate, interstate, and international mobile sources.** An owner or operator must use the methods in WAC 173-441-080 to determine which emissions are generated within Washington state from intrastate, interstate, and international nonroad mobile sources when determining if a fleet of nonroad mobile sources meet the reporting threshold established in (a) of this subsection.

(c) **Reporting total emissions of greenhouse gases.** Once an owner or operator determines that the direct emissions from a site or fleet of nonroad mobile sources meet the reporting threshold established in (a) of this subsection, the owner or operator is responsible for reporting its total emissions of greenhouse gases from the site or fleet of nonroad mobile sources.

(d) **Report consistency requirements for 2009 emissions reported in 2010.** For 2009 emissions reported in 2010, the report consistency requirements in WAC 173-441-090 do not apply.

(3) **Reporting 2010 emissions in 2011.** The thresholds and reporting requirements for 2010 emissions reported in 2011 are specified below. Refer to Figure 060.1 of this section for a flow chart showing how to apply the reporting thresholds for 2010 emissions reported in 2011.

(a) **Reporting threshold for 2010 emissions reported in 2011.** For 2010 emissions reported in 2011, the reporting threshold for sources other than fleets of on-road motor vehicles is ten thousand metric tons of direct emissions, expressed as CO_2e.

(b) **Threshold determination for 2010 emissions reported in 2011.** An owner or operator with multiple sites or fleets of nonroad mobile sources within Washington state must calculate the direct emissions for each site and fleet of nonroad mobile sources separately. Each site or fleet of nonroad mobile sources that has direct emissions of at least ten thousand metric tons of CO_2e is subject to the reporting requirements of this chapter. For 2010 emissions reported in 2011, an owner or operator is not required to report emissions from a site or fleet of nonroad mobile sources with direct emissions less than ten thousand metric tons of CO_2e.

(i) **Sites.** For 2010 emissions reported in 2011, when determining whether the direct emissions of a site meet the ten thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from any source or combination of sources of emissions located on the site, including all mobile sources that operate exclusively within the boundaries of the site.

(ii) **Fleet of marine vessels.** For 2010 emissions reported in 2011, when determining whether the direct emissions of a fleet of marine vessels meet the ten thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from all marine vessels operating in Washington state beyond the boundaries of a single site.

(iii) **Fleet of rail equipment.** For 2010 emissions reported in 2011, when determining whether the direct emissions of a fleet of rail equipment meet the ten thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from all rail equipment operating in Washington state.

(iv) **Fleet of aircraft.** For 2010 emissions reported in 2011, emissions from intrastate, interstate, and international fleets of aircraft are not required to be reported.

(v) **Intrastate, interstate, and international mobile sources.**

An owner or operator must use the methods in WAC 173-441-080 to include emissions generated within Washington state from intrastate, interstate, and international nonroad mobile sources when determining if a fleet of nonroad mobile sources meets the reporting threshold established in (a) of this subsection.

(c) **Reporting total emissions of greenhouse gases.** Once an owner or operator determines that the direct emissions from a site or fleet of nonroad mobile sources meet the reporting threshold established in (a) of this subsection, the owner or operator is responsible for reporting its total emissions of greenhouse gases from the site or fleet of nonroad mobile sources.

(d) **Report consistency.** For 2010 emissions reported in 2011, the report consistency requirements in WAC 173-441-090 do not apply.

(4) **Reporting 2011 emissions in 2012.** The thresholds and reporting requirements for 2011 emissions reported in 2012 are specified below. Refer to Figure 060.1 of this section for a flow chart of how to apply the reporting thresholds for 2011 emissions reported in 2012.

(a) **Reporting threshold for 2011 emissions reported in 2012.** For 2011 emissions reported in 2012 the reporting threshold for sources other than fleets of on-road motor vehicles is ten thousand metric tons of direct emissions, expressed as CO_2e.

(b) **Threshold determination for 2011 emissions reported in 2012.** An owner or operator with multiple sites or fleets of nonroad mobile sources within Washington state must calculate the direct emissions for each site and fleet of nonroad mobile sources separately. Each site or fleet of nonroad mobile sources that has direct emissions of at least ten thousand metric tons of CO_2e is subject to the reporting requirements of this chapter. For 2011 emissions reported in 2012, an owner or operator is not required to report emissions from a site or fleet of nonroad mobile sources with direct emissions less than ten thousand metric tons of CO_2e.

(i) **Sites.** For 2011 emissions reported in 2012, when determining whether the direct emissions of a site meet the ten thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from any source or combination of sources of emissions located on the site, including all mobile sources that operate exclusively within the boundaries of the site.

(ii) **Fleet of marine vessels.** For 2011 emissions reported in 2012, when determining whether the direct emissions of a fleet of marine vessels meet the ten thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from all marine vessels operating in Washington state beyond the boundaries of a single site.

(iii) **Fleet of rail equipment.** For 2011 emissions reported in 2012, when determining whether the direct emissions of a fleet of rail equipment meet the ten thousand metric tons of CO_2e reporting threshold, an owner or operator must include the direct emissions from all rail equipment operating in Washington state.

(iv) **Fleet of aircraft.** For 2011 emissions reported in 2012, emissions from intrastate, interstate, and international fleets of aircraft are not required to be reported.

(v) **Intrastate, interstate, and international mobile sources.** An owner or operator must use the methods in WAC 173-441-080 to determine which emissions are generated within Washington state from intrastate, interstate, or international nonroad mobile sources when determining if a fleet of nonroad mobile sources meets the reporting threshold established in (a) of this subsection.

(c) **Reporting total emissions of greenhouse gases.** Once an owner or operator determines that the direct emissions from a site or fleet of nonroad mobile sources meet the reporting threshold established in (a) of this subsection, the owner or operator is responsible for reporting its total emissions of greenhouse gases from the site or fleet of nonroad mobile sources.

(d) **Report consistency.** For 2011 emissions reported in 2012 and subsequent years, the report consistency requirements in WAC 173-441-090 do apply.

(5) **Reporting 2012 emissions in 2013 and reporting in subsequent years.** The thresholds and reporting requirements for 2012 emissions reported in 2013 and for each year after are specified below. Refer to Figure 060.2 of this section for a flow chart showing how to apply the reporting thresholds beginning with 2012 emissions reported in 2013.

(a) **Reporting threshold for 2012 emissions reported in 2013 and all future reporting years.** For 2012 emissions reported in 2013 and all future reporting years the reporting threshold for sources other than fleets of on-road motor vehicles is ten thousand metric tons of direct emissions, expressed as CO_2e.

(b) **Threshold determination for 2012 emissions reported in 2013 and all future reporting years.** Beginning with 2012 emissions reported in 2013 and for all future years, an owner or operator must combine direct emissions from all sites and fleets of nonroad mobile sources located in Washington state when determining whether the direct emissions meet the ten thousand metric tons of CO_2e reporting threshold.

(i) **Intrastate aircraft.** Beginning with 2012 emissions reported in 2013, an owner or operator of intrastate aircraft, defined as aircraft with flights that have both the takeoff and landing located inside Washington state must:

(A) Include direct emissions of greenhouse gases from the intrastate aircraft when determining if the combined direct emissions from sites and fleets of nonroad mobile sources meet the reporting threshold of ten thousand metric tons of greenhouse gases per year, expressed as CO_2e; and

(B) Report the total emissions of greenhouse gases from the intrastate aircraft if the reporting threshold is met.

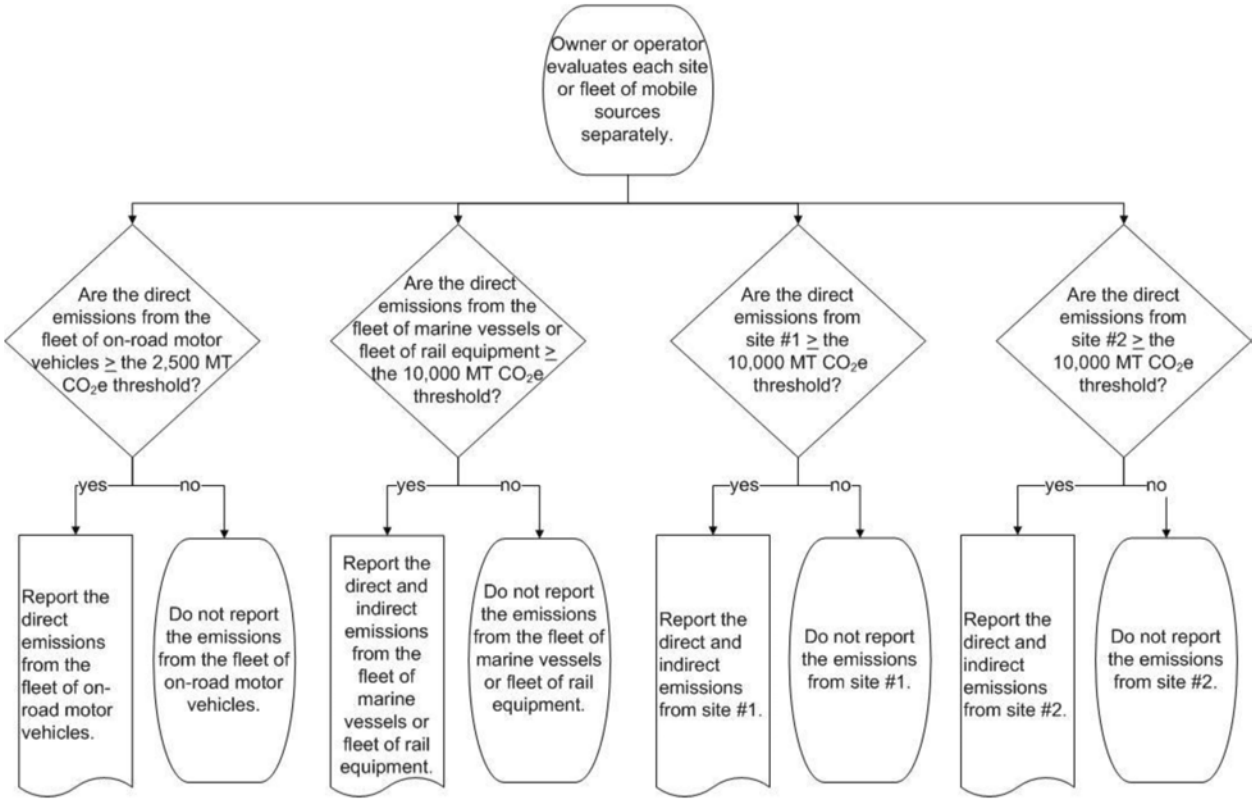
(ii) **Intrastate, interstate, or international nonroad mobile sources.** An owner or operator must use the methods in WAC 173-441-080 to determine which emissions are generated within Washington state from intrastate, interstate, or international nonroad mobile sources when determining if a fleet of nonroad mobile sources meets the reporting threshold established in (a) of this subsection.

(c) **Reporting total emissions of greenhouse gases.** Once an owner or operator determines that the combined direct emissions from all sites and fleets of nonroad mobile sources meet the reporting threshold established in (a) of this subsection, the owner or operator is responsible for reporting its total emissions of greenhouse gases, including emissions generated within Washington state from its fleet of on-road motor vehicles operating beyond the boundaries of a single site.

Table 060.1. Phasing Schedule for a Source or Combination of Sources of Emissions

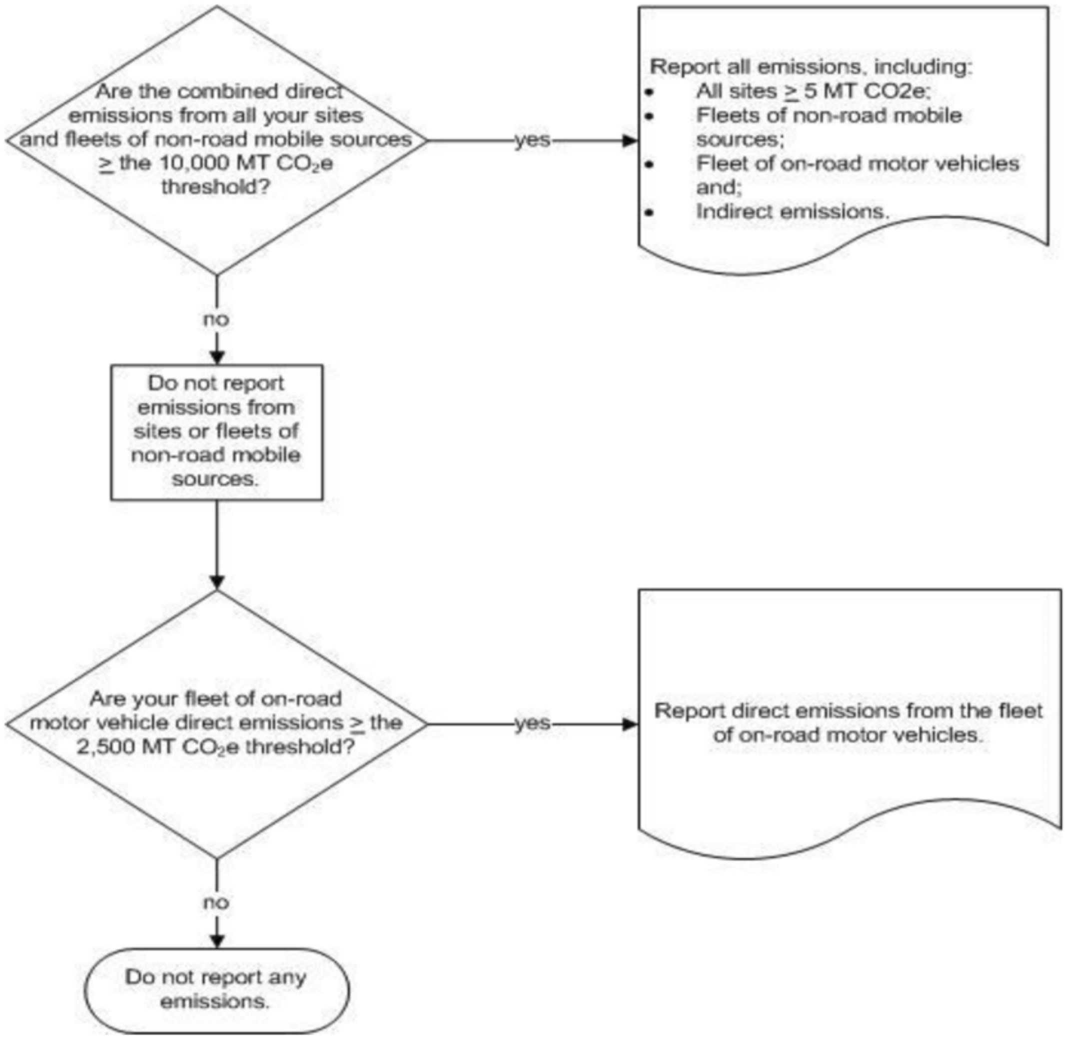
Draft Rule Subsection	Emissions Year	Application of Reporting Threshold	Reporting Threshold for a Source of Emissions
WAC 173-441-060(2)	2009 (2010 report)	Each site or fleet of nonroad mobile sources	≥ 25,000 MT CO_2e of direct emissions
		Fleets of on-road motor vehicles	≥ 2,500 MT CO_2e of direct emissions
WAC 173-441-060(3)	2010 (2011 report)	Each site or fleet of nonroad mobile sources	≥ 10,000 MT CO_2e of direct emissions
		Fleets of on-road motor vehicles	≥ 2,500 MT CO_2e of direct emissions
WAC 173-441-060(4)	2011 (2012 report)	Each site or fleet of nonroad mobile sources	≥ 10,000 MT CO_2e of direct emissions
		Fleets of on-road motor vehicles	≥ 2,500 MT CO_2e of direct emissions
WAC 173-441-060(5)	2012 (2013 report) and subsequent years	Combined direct emissions from all sites and fleets of nonroad mobile sources	≥ 10,000 MT CO_2e of direct emissions
		Fleets of on-road motor vehicles	≥ 2,500 MT CO_2e of direct emissions

Figure 060.1. Applying Reporting Thresholds for 2009 Emissions Reported in 2010*, 2010 Emissions Reported in 2011, and 2011 Emissions Reported in 2012



* NOTE: For 2009 emissions to be reported in 2010, replace 10,000 MT CO_2e with 25,000 MT CO_2e.

Figure 060.2. Applying Reporting Thresholds for 2012 Emissions Reported in 2013 and All Future Reporting Years



<u>NEW SECTION</u>

WAC 173-441-065 Deferred reporting requirements for owners or operators of interstate or international mobile sources. Owners or operators are not required to report emissions from flights of interstate or international commercial aircraft for which either the takeoff or landing occur outside Washington state. Emissions from intrastate aircraft must be reported beginning with 2012 emissions reported in 2013 as described in WAC 173-441-060(5).

NEW SECTION

WAC 173-441-070 Reporting requirements when direct emissions of greenhouse gases fall below reporting thresholds. The following reporting requirements apply when direct emissions of greenhouse gases fall below the applicable reporting threshold in WAC 173-441-040:

(1) **Submitting a written petition to end reporting requirements.** A reporter may submit a written petition to the department to end the reporting requirements under this chapter when there is a change in operations that results in the permanent reduction of direct emissions below the applicable reporting threshold or when the emissions source permanently ceases operations. The petition must include a detailed description of the change in operations, supporting data to document the permanent change or cessation in operations, documentation of the emissions after the change in operations, and any other information as requested by the department. If the petition is not approved by the department, the reporting requirements in subsection (2) of this section apply when direct emissions of greenhouse gases fall below the applicable reporting threshold. An approval or denial issued by the department in response to a written petition filed under this subsection is a determination appealable to the pollution control hearings board per RCW 43.21B.110 (1)(h).

(2) **Reporting requirements when direct emissions of greenhouse gases fall below the applicable reporting threshold.** Unless the reporter has received an approval to end reporting requirements pursuant to subsection (1) of this section, the reporter must continue to submit an annual emissions report when greenhouse gas emissions change such that the direct emissions fall below the applicable annual reporting threshold in WAC 173-441-040. The reporter must continue to submit an annual emissions report until direct emissions are below the applicable reporting threshold for a minimum of three consecutive years. When direct emissions are below the applicable reporting threshold for three consecutive years, the reporter is not subject to the reporting requirements of this chapter until direct emissions exceed the applicable threshold in any future calendar year.

NEW SECTION

WAC 173-441-080 Determining if greenhouse gas emissions from mobile sources occur in Washington state. An owner or operator of mobile sources must use the following methods consistently throughout its organization and over time to determine if its emissions occur in Washington state. Emissions that occur while a mobile source is in port, hotelling, or idling are considered to occur in the state in which the mobile source is located at the time of the activity and are the responsibility of the owner or operator of the mobile source.

(1) **Determining if greenhouse gas emissions from mobile sources that operate exclusively within the boundaries of a single site occur in Washington state.** If a mobile source operates exclusively within the boundaries of a single site, then the greenhouse gas emissions from the mobile sources are part of the emissions of the site. All rail equipment operating in Washington state, including rail equipment operating exclusively in a single rail yard or other restricted location, is considered part of the fleet of rail equipment instead of being part of a site.

(2) **Determining if greenhouse gas emissions from on-road motor vehicles occur in Washington state.** An owner or operator of on-road motor vehicles must use the following methods to determine if its greenhouse gas emissions occur in Washington state. An owner or operator may use a combination of Method 1 and Method 2 to determine if emissions occur in Washington state provided that all vehicles from the same vehicle size class use the same method and that the methods are applied consistently throughout the fleet of on-road motor vehicles and over time.

(a) **Method 1: Miles traveled within Washington state by the on-road motor vehicles.** Assign emissions to Washington state based on the documented location of miles the on-road motor vehicle travels inside the state. The owner or operator may report activity data based on mileage location information, or prorate activity data based on the ratio of miles traveled inside of Washington state to the total miles traveled by the interstate or international fleet of on-road motor vehicles; or

(b) **Method 2: Fuel transferred to on-road motor vehicles within Washington state.** Assign emissions to Washington state based on the documented location of fuel transfers to on-road motor vehicles. The owner or operator may report activity data based on fuel transfer location information, or prorate activity data based on the ratio of fuel transferred to on-road motor vehicles inside of Washington state to the total fuel transferred to the interstate or international fleet of on-road motor vehicles. Fuel purchase location can be used to document fuel transfer location if the refueling location is the point of purchase of the fuel; or

(c) **Method 3: All emissions generated by on-road motor vehicles licensed in Washington state.** Assign all of the on-road motor vehicle's emissions to Washington state if the on-road motor vehicle is licensed in Washington state. Do not report emissions from on-road motor vehicles registered outside the state of Washington. Method 3 must not be combined with Method 1 or Method 2. The owner or operator may only use Method 3 if mileage location or fuel transfer location is not available due to limitations imposed by rental agreements.

(3) **Determining if greenhouse gas emissions from aircraft occur in Washington state.** An owner or operator must assign a flight's greenhouse gas emissions to Washington state if both the takeoff and landing are located inside Washington state. For flights with multiple legs, each leg must be evaluated as a unique

flight.

(4) **Determining if greenhouse gas emissions from marine vessels occur in Washington state.** An owner or operator of marine vessels must use the appropriate method or methods from the list below to determine if its greenhouse gas emissions occur in Washington state. The methods must be applied in the order in which they are listed. Figure 080.1 of this section shows a graphical representation of the reporting area for marine vessels.

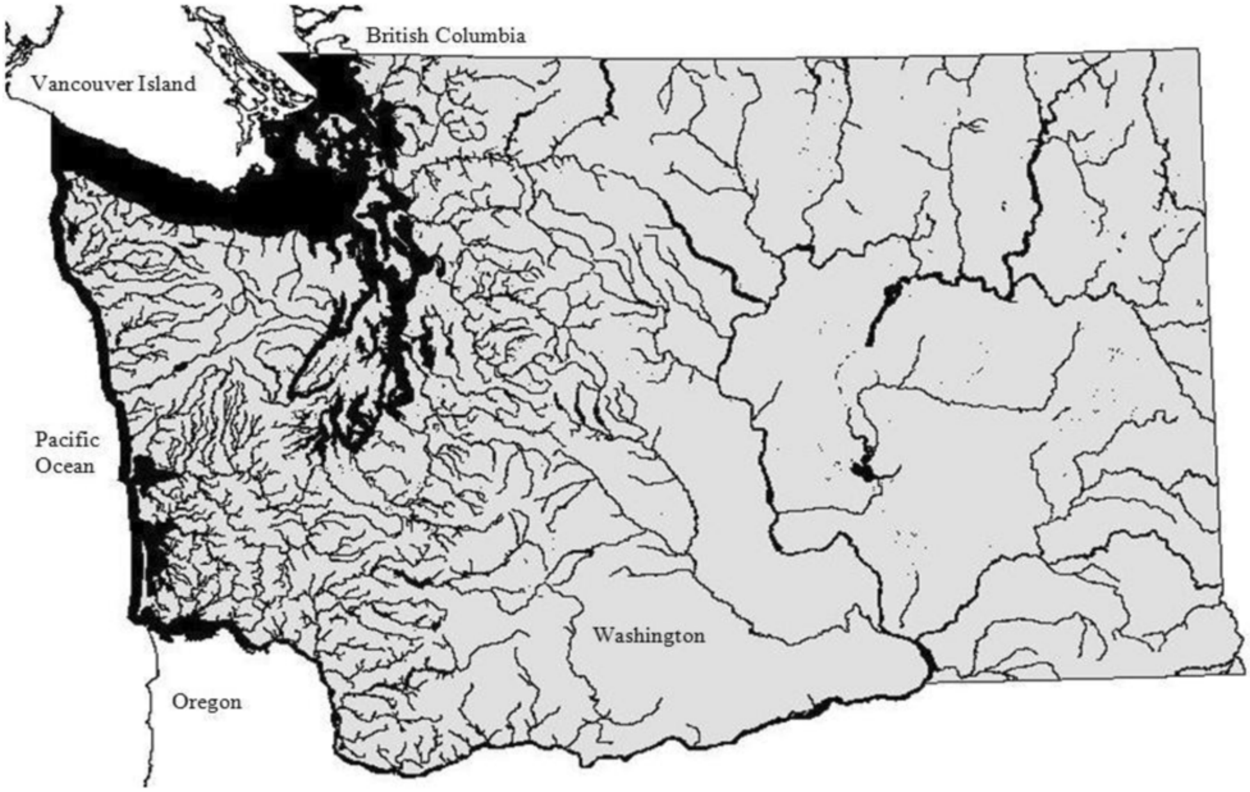
(a) **Intrastate marine vessel voyages.** If a marine vessel's arrival and departure points are both inside the waters of the state, then the owner or operator must assign the voyage's greenhouse gas emissions to Washington state.

(b) **Marine vessel voyages transiting Puget Sound.** If a marine vessel transits Puget Sound, the Strait of Juan de Fuca, Haro Strait, or the Strait of Georgia then the owner or operator must assign to Washington state the greenhouse gas emissions occurring in those waters if the point of arrival or last departure is within the waters of the state of Washington. The reportable emissions occurring in Puget Sound are defined as all activities between the point of arrival or last departure and three nautical miles west of the mean low-water mark of Cape Flattery for the Strait of Juan de Fuca, 48°40'00" N latitude for Haro Strait, or 49°00'00" N latitude for the Strait of Georgia. The international border marks the western limit of the reporting area for the Strait of Georgia and Boundary Pass. Figure 080.2 of this section shows a graphical representation of the reporting area for marine vessels in Puget Sound.

(c) **Marine vessel voyages in rivers that form the state border.** If a marine vessel operates in a river that forms a border of Washington, then the owner or operator must assign to Washington state half of the greenhouse gas emissions occurring in the stretch of the river located on the border of Washington state beginning three nautical miles downstream of the river mouth. The owner or operator must assign to Washington state all of the emissions occurring in any stretch of river located completely in Washington state. The owner or operator may report activity data based on hours of operation information, or prorate activity data based on the ratio of hours operated exclusively inside of the waters of the state to the total hours operated on the voyage.

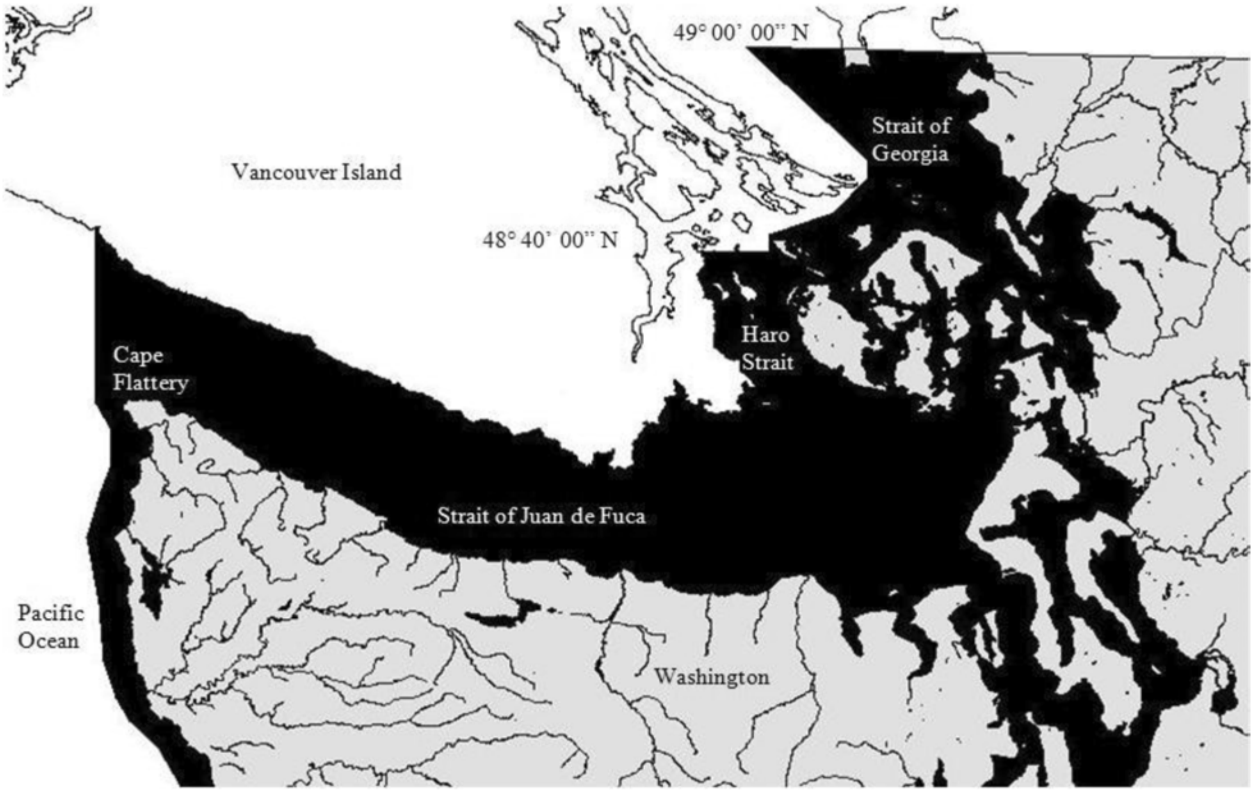
(d) **All other interstate marine vessel voyages.** If either the arrival or departure point is outside of the waters of the state, then the owner or operator must assign to Washington state the greenhouse gas emissions occurring in Washington state based on the documented hours the voyage occurs inside the waters of the state. The owner or operator may report activity data based on hours of operation information, or prorate activity data based on the ratio of hours operated inside of the waters of the state to the total hours operated on the voyage.

Figure 080.1. Reporting Area for Marine Vessels



Report emissions occurring in the black or gray shaded areas according to the methods outlined in WAC 173-441-080(4).

Figure 080.2. Reporting Area for Marine Vessels in Puget Sound



Report emissions occurring in the black or gray shaded areas according to the methods outlined in WAC 173-441-080(4).

(5) **Determining if greenhouse gas emissions from rail equipment occur in Washington state.** An owner or operator of rail equipment must use the following methods to determine if its emissions occur in Washington state. An owner or operator may use different methods for line haul powered rail equipment, yard powered rail equipment, and unpowered rail equipment, provided that all rail equipment of the same type uses the same method and the methods are applied consistently throughout the fleet of rail equipment and over time.

(a) **Intrastate rail equipment.** Assign all of the rail equipment's greenhouse gas emissions to Washington state if the rail equipment operates exclusively within Washington state.

(b) **Percentage of total gross ton-miles operated within Washington state by the rail equipment.** Assign emissions to Washington state based on the documented gross ton-miles the rail equipment operates inside the state relative to the total gross ton-miles operated by the owner or operator. An owner or operator using this method must prorate activity data based on the ratio of gross ton-miles operated inside of Washington to the total gross ton-miles operated in the United States or North America by the owner or operator. For Class I railroads, data must be consistent with data reported on its annual report to the surface transportation board.

(c) **Hours operated within Washington state by the rail**

equipment. Assign emissions to Washington state based on the documented hours the rail equipment operates inside the state. The owner or operator may report activity data based on hours of operation information, or prorate activity data based on the ratio of hours operated inside of Washington to the total hours operated by the interstate or international fleet of rail equipment.

NEW SECTION

WAC 173-441-090 Report consistency. A reporter must consistently report greenhouse gas emissions over time except as follows:

(1) **Switching to a higher tier method.** A reporter may switch to an equivalent or higher tier method provided that the reporter continues to use the new method in subsequent reporting years.

(2) **Switching to a lower tier method.** A reporter must not switch to a lower tier method unless the data required to perform the analysis required in the previously used method is no longer available due to process or organizational changes.

(3) **Adjusting emissions reports from previous years due to a change in methods.** If a reporter makes a change in reporting methodologies that results in a change of five percent or larger in either the reporter's total direct or total indirect CO_2e emissions, then the reporter must adjust emissions reports from all previous years within the document retention period described in WAC 173-441-160 to account for the change. If the activity data needed to use the new method is not available for previous emission years, then the reporter must clearly describe the change in methodology and document the lack of activity data in the emissions report, but is not required to recalculate emissions for previous years. All changes and documentation relating to previous emission years must be submitted as part of the current year's reporting activities and be in accordance with WAC 173-441-150(5). The requirement to adjust emissions reports from previous years due to a change in methods begins with 2011 emissions reported in 2012 and does not apply to 2009 emissions reported in 2010 and 2010 emissions reported in 2011.

(4) **Phasing of report consistency requirements.** For 2009 emissions reported in 2010 and 2010 emissions reported in 2011, the report consistency requirements of this section do not apply. An owner or operator may switch methods during this time. The requirement to adjust emissions reports from previous years due to a change in methods begins with 2011 emissions reported in 2012 and does not apply to 2009 emissions reported in 2010 and 2010 emissions reported in 2011.

NEW SECTION

WAC 173-441-095 Reserved.

NEW SECTION

WAC 173-441-100 Quantification methods for emissions from a source or combination of sources of emissions. Reporters subject to the reporting threshold in WAC 173-441-040 (1)(a) must use the following quantification methods to calculate emissions.

(1) **Simplified estimation methods.** A reporter may use simplified estimation methods for sources that meet the requirements of WAC 173-441-130. Simplified estimation methods are not considered tiered methods, and emissions calculated using simplified estimation methods must be reported separately.

(2) **Alternative quantification methods approved by petition.** A reporter may petition the department to use alternative quantification methods to those specified in subsection (4)(a), (c), or (d) of this section to calculate its direct stationary greenhouse gas emissions. Such alternative quantification methods must be approved by the department prior to reporting and must meet the requirements of WAC 173-441-120.

(3) **Biomass.** All reporters must account for and separately report greenhouse gas emissions from the combustion of biomass.

(a) Emissions of CO_2 from biomass combustion must be calculated using the methodologies in Chapter 12 of *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008). A reporter must use the highest tier possible based on the reporter's existing monitoring systems and available data. A reporter must report CO_2 emissions from fossil fuel combustion separately from CO_2 emissions from biomass combustion. Emissions of CH_4 and N_2O from biomass combustion are direct emissions and are not treated separately from CH_4 and N_2O from fossil fuel combustion.

(b) For facilities that combust municipal solid waste (MSW), the CO_2 emissions from combusting the biomass portion of MSW (e.g., wood, yard waste, paper products) must be separately calculated and reported as biomass CO_2 emissions using the methodologies found in the California Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Section 95125 (h)(2) adopted on December 2, 2008, and codified in the California Code of Regulations at 17 CCR Section 95125 (h)(2).

(4) **Direct emissions of greenhouse gases.** Reporters subject to the reporting threshold in WAC 173-441-040 (1)(a) must use the following quantification methods to calculate direct emissions of greenhouse gases:

(a) **Quantifying direct emissions from stationary combustion.** Unless the department has approved an alternative quantification methodology pursuant to WAC 173-441-120, reporters must use the following quantification methods to calculate direct emissions of greenhouse gases from stationary combustion sources:

(i) All stationary combustion sources except oil refineries must calculate greenhouse gas emissions using one of the tiered methods in Chapter 12 of *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008). A reporter must use the highest tier possible based on the reporter's existing monitoring systems and available data.

(ii) Stationary combustion sources at an oil or petroleum refinery must calculate greenhouse gas emissions using one of the tiered methods in WAC 173-441-510 unless the source is included in WAC 173-441-520 or 173-441-530. A reporter must use the highest tier possible based on the reporter's existing monitoring systems and available data.

(b) **Quantifying direct emissions from mobile sources.** Reporters must use the following quantification methods to calculate direct emissions of greenhouse gases from mobile sources:

(i) **Quantifying direct combustion emissions from nonroad mobile sources.** Direct combustion emissions of greenhouse gases from nonroad mobile sources must be calculated using one of the tiered methods in Chapter 13 of *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008).

(ii) **Quantifying direct fugitive emissions from nonroad mobile sources.** Direct fugitive emissions of greenhouse gases from nonroad mobile sources must be calculated according to the methods described in (d) of this subsection.

(iii) **Quantifying direct combustion emissions from auxiliary power units.** Direct combustion emissions of greenhouse gases from the combustion of fuels in auxiliary power units must be calculated using one of the tiered methods in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 12 or Chapter 13.

(iv) **Quantifying direct emissions from on-road motor vehicles.** Direct combustion emissions of greenhouse gases from on-road motor vehicles must be calculated according to the methods described in WAC 173-441-110.

(c) **Quantifying direct process emissions.** Unless the department has approved an alternative quantification methodology pursuant to WAC 173-441-120, reporters must use the appropriate methodology referenced in Table 100.1 of this section to calculate direct emissions of greenhouse gases from physical and chemical processes. A reporter must use the highest tier possible based on the reporter's existing monitoring systems and available data.

Table 100.1. Quantification Methods for Process Emissions

Industry	Reference Methodology
Aluminum	TCR GRP, Appendix E.2: Tier A using plant specific emission factors or Tier B using default factors.
Cement	TCR GRP, Appendix E.4: Clinker Method using Tier A plant specific clinker emission factor.
Iron & steel	TCR GRP, Appendix E.7: Tier A using plant specific carbon content emission factors or Tier B using default carbon content emission factors.

Industry	Reference Methodology
Lime	TCR GRP, Appendix E.8: Tier A1 or Tier A2 using plant specific emission factors; Tier B using default emission factors; or Tier C using default emission factors.
Pulp & paper	TCR GRP, Appendix E.10: Tier A using default stoichiometric emission factors.
Semi-conductor	TCR GRP, Appendix E.12: Tier A, Tier B, or Tier C.
Natural gas extraction, processing, storage, transmission and distribution	WAC 173-441-500.
Hydrogen plant	WAC 173-441-530.
Petroleum refinery	WAC 173-441-520.
Other process emission sources	Use the applicable TCR GRP, Appendix E process emissions methodology. If no TCR process emissions protocol is applicable, contact the department.

(d) **Quantifying direct fugitive emissions.** Unless the department has approved an alternative quantification methodology pursuant to WAC 173-441-120, reporters must use the following quantification methods to calculate direct fugitive emissions of greenhouse gases:

(i) **Fugitive emissions from refrigeration and air conditioning.** Greenhouse gas fugitive emissions from refrigeration and air conditioning must be calculated using Tier A or B methods as given in Chapter 16 of *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008). For stationary sources, a reporter must use the highest tier possible based on the reporter's existing monitoring systems and available data. The tier selection restriction does not apply to refrigeration or air conditioning units that are part of a mobile source. A reporter may use the screening method given in Chapter 16 of *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) for sources that qualify for simplified estimation methods as described in WAC 173-441-130. The screening method is only considered to be a tiered method when applied to on-road motor vehicles.

(ii) **SF_6 fugitive emissions from electricity transmission and distribution.** SF_6 fugitive emissions from electricity transmission and distribution must be calculated using the methodology referenced in Appendix E.5 of *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008).

(iii) **Fugitive emissions from industrial and municipal wastewater treatment emissions.** Fugitive greenhouse gas emissions from industrial wastewater treatment systems at pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities must be calculated using the methodologies described in WAC 173-441-550. Fugitive greenhouse gas emissions from municipal wastewater treatment systems must be calculated using the methodologies described in *Local Government Operations Protocol, For the Quantification and Reporting of Greenhouse Gas Emissions Inventories*, Version 1 (September 2008).

(iv) **Fugitive emissions from industrial landfill operations.** Fugitive greenhouse gas emissions, including fugitive methane emissions, from landfill operations must follow the methodologies outlined in WAC 173-441-540.

(v) **Fugitive emissions from coal piles.** Fugitive greenhouse gas emissions from coal piles must be calculated using the methodologies described in WAC 173-441-560.

(vi) **Other fugitive emissions.** Contact the department if there is no quantification methodology listed in this section for a source of fugitive emissions. Some sources of fugitive emissions may qualify for simplified estimation methods as described in WAC 173-441-130.

(5) **Indirect emissions of greenhouse gases.** Reporters must use the following quantification methods to calculate indirect emissions of greenhouse gases:

(a) **Quantifying indirect emissions of greenhouse gases from the use of purchased electricity.** Indirect emissions of greenhouse gases from the purchase and use of electricity must be quantified using one of the following methods. A reporter must use the highest tier possible based on the reporter's existing monitoring systems and available data.

(i) Tier A methodology in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 14. If the reporter purchases electricity directly from a known electric generation source then the reporter must use generator-specific emission factors; or

(ii) Tier A2 methodology must use the most recent CO_2 utility-specific emission factor (lbs/MWh) calculated and published annually by the Washington state department of commerce from data obtained during the fuel mix disclosure process required under chapter 19.29A RCW. For the most accurate estimation of the CO_2 utility-specific emission factor, utilities providing data under this fuel mix disclosure process must use the average system mix methodology described in WAC 173-441-800. The reporter must use the CO_2 utility-specific emission factor in combination with the most recent Northwest Power Pool eGRID default factors for methane and nitrous oxide published by the U.S. Environmental Protection Agency; or

(iii) Tier B methodology in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 14. Tier B must use the most recent Northwest Power Pool eGRID default factors published by the U.S. Environmental Protection Agency.

(b) **Quantifying indirect emissions of greenhouse gases from imported steam, district heating, cooling, and electricity from a combined heat and power plant.** Reporters must use the following quantification methods to calculate indirect emissions of greenhouse gases from imported steam, district heating, cooling, and electricity from a combined heat and power plant:

(i) Indirect emissions from stationary sources must be calculated using the Tier A or B methods in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapters 12, 15, and 16. The determination of Tier A or B is based on the quality of information supplied by the district heating, cooling or cogeneration facility. A reporter must use the highest tier possible based on the reporter's existing monitoring systems and available data.

(ii) The owner or operator of a cogeneration, district heating, or district cooling plant must provide greenhouse gas emissions information to all purchasers of heating, cooling, or electricity who are reporters under this chapter, upon request from the reporter. The emissions information must be provided in units appropriate for the reporter to use in formulating its annual emissions report. I.e., electricity in units of kg CO_2e/MWh, steam in units of kg CO_2e/1,000 lbs of steam purchased or kg CO_2e/mmBtu of steam, cooling in terms of kg/ton of cooling, etc.

(6) **Global warming potential factors for converting emissions of greenhouse gases to CO_2e values.** The following global warming potential factors in Table 100.2 and Table 100.3 of this section must be used when converting emissions of greenhouse gases to CO_2e values. To convert to CO_2e values, multiply the quantity of each greenhouse gas in metric tons by the listed GWP. If a refrigerant blend is not listed in Table 100.3 of this section but contains a greenhouse gas listed in Table 100.2 of this section, then use the GWPs in Table 100.2 to calculate the GWP for the blend. To calculate the GWP for the refrigerant blend, take the weighted average by mass of the GWPs of the component substances. If the refrigerant blend contains a substance not listed in Table 100.2 of this section, then use zero for the GWP for that substance when calculating the weighted average.

Table 100.2. Global Warming Potential Factors for Required Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43*
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12*
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300*
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200*
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950*
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890*
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200

Common Name	Formula	Chemical Name	GWP
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

Source: Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report published in 1995, unless no value was assigned in the document. In that case, the GWP values are from the IPCC Third Assessment Report published in 2001 (those marked with *). GWP values are from the Second Assessment Report (unless otherwise noted) to be consistent with international practices. Values are 100-year GWP values.

Table 100.3. Global Warming Potential Factors for Required Refrigerant Blends

Refrigerant Blend	Global Warming Potential	Refrigerant Blend	Global Warming Potential
R-401A	18	R-413A	1,774
R-401B	15	R-414A	0
R-401C	21	R-414B	0
R-402A	1,680	R-415A	25
R-402B	1,064	R-415B	105
R-403A	1,400	R-416A	767
R-403B	2,730	R-417A	1,955
R-404A	3,260	R-418A	4
R-406A	0	R-419A	2,403
R-407A	1,770	R-420A	1,144
R-407B	2,285	R-500	37
R-407C	1,526	R-501	0
R-407D	1,428	R-502	0
R-407E	1,363	R-503	4,692
R-408A	1,944	R-504	313
R-409A	0	R-505	0
R-409B	0	R-506	0
R-410A	1,725	R-507 or R-507A	3,300
R-410B	1,833	R-508A	10,175
R-411A	15	R-508B	10,350
R-411B	4	R-509 or R-509A	3,920
R-412A	350		

Source: ASHRAE Standard 34 via Chapter 16 of *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008)

NEW SECTION

WAC 173-441-110 Quantification methods for on-road motor vehicles. A reporter of emissions from on-road motor vehicles must use the following quantification methods to calculate its emissions.

(1) **Simplified estimation methods.** A reporter may use simplified estimation methods for sources that meet the requirements of WAC 173-441-130(2). Simplified estimation methods are not considered tiered methods, and emissions calculated using simplified estimation methods must be reported separately.

(2) **Biomass.** All reporters must account for and separately report greenhouse gas emissions from the combustion of biomass.

(a) **Quantifying of biomass emissions from on-road motor vehicle fuels with greater than or equal to fifty percent biomass content.** Reporters of emissions from on-road motor vehicle fuels with fifty percent or greater biomass must use the following quantification methods to calculate their greenhouse gas emissions from the combustion of biomass:

(i) A reporter must report the percentage of fuel derived from biomass for all fuels that are fifty percent or more biomass.

(ii) A reporter must adjust the emission factors of any fuel that is fifty percent or more biomass by reporting the fuel in two components. The biomass portion of the fuel must be calculated using the emissions factor for the pure biomass fuel and the nonbiomass portion of the fuel must be calculated using the emissions factor for the corresponding pure nonbiomass fuel found in (c) of this subsection.

(b) **Quantifying of biomass emissions from on-road motor vehicle fuels with less than fifty percent biomass content.** Reporters of emissions from on-road motor vehicle fuels with less than fifty percent biomass content must use the following quantification methods to calculate their greenhouse gas emissions from the combustion of biomass:

(i) A reporter may report the percentage of fuel derived from biomass for all fuels that are less than fifty percent biomass.

(ii) A reporter may choose to report all emissions as nonbiomass for any fuel with less than fifty percent biomass content. Alternately, the reporter may adjust the fuel's emission factors by reporting the fuel in two components. The biomass portion of the fuel may be calculated using the emissions factor for the pure biomass fuel and the nonbiomass portion of the fuel may be calculated using the emissions factor for the corresponding pure nonbiomass fuel found in (c) of this subsection.

(c) **Corresponding fuel types for on-road motor vehicles.** Reporters of emissions from on-road motor vehicles must use the following corresponding fuel types when determining the biomass content of fuels used in on-road motor vehicles:

(i) Biodiesel is considered the biomass fuel corresponding to diesel.

(ii) Ethanol is considered the biomass fuel corresponding to gasoline.

(iii) For all other fuels use the same emissions factors for both biomass and nonbiomass fuel components.

(3) **Direct emissions of greenhouse gases.** Reporters of emissions from on-road motor vehicles must use the following quantification methods to calculate their direct emissions of greenhouse gases:

(a) **Quantifying CO_2 emissions from on-road motor vehicles.** Direct emissions of CO_2 from on-road motor vehicles must be calculated using one of the tiered methods in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 13.

(b) **Quantifying CH_4 and N_2O emissions from on-road motor vehicles.** Direct emissions of CH_4 and N_2O from on-road motor vehicles must be calculated using one of the tiered methods in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 13.

(c) **Quantifying fugitive emissions from refrigeration and air conditioning from on-road motor vehicles.** Fugitive emissions from refrigeration and air conditioning from on-road motor vehicles must be calculated using one of the tiered methods in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 16. The department will accept the screening method located in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 16 as a tiered method for on-road motor vehicles.

(d) **Quantifying direct combustion emissions from auxiliary power units.** Direct emissions from the combustion of fuels in auxiliary power units that are carried on or moved by on-road motor vehicles must be calculated using one of the tiered methods in *The Climate Registry's General Reporting Protocol*, Version 1.1 (May 2008) Chapter 12 or Chapter 13.

(4) **Converting emissions of greenhouse gases to CO_2e values.** The global warming potential factors found in WAC 173-441-100(6) must be used when converting emissions of greenhouse gases to CO_2e values.

NEW SECTION

WAC 173-441-120 Petitioning the department to use an alternative quantification method to calculate greenhouse gas emissions. A reporter may petition the department to use alternative quantification methods to those specified in WAC 173-441-100 (4)(a), (c), or (d) to calculate its direct stationary greenhouse gas emissions. To be considered by the department, the alternative quantification method must be a well recognized and widely accepted method developed by a body such as the U.S. Environmental Protection Agency, World Resources Institute, Intergovernmental Panel on Climate Change, The Climate Registry, California Air Resources Board, or other similar nationally accepted body. The following requirements apply to the submission, review, and approval or denial of a petition:

(1) **Petition submittal.** A reporter must submit a petition that meets the following conditions before the department may review the petition and issue a determination.

(a) **Timing.** A reporter must submit a complete petition no later than one hundred eighty days prior to the emissions report deadline established in WAC 173-441-140. Such petition must include sufficient information, as described in (b) of this subsection, for the department to determine whether the proposed alternative quantification method will provide emissions data sufficient to meet the reporting requirements of RCW 70.94.151.

The department will notify the reporter within thirty days of receipt of a petition of any additional information the department requires to approve the proposed quantification methods in the petition. The department will issue a determination within sixty days of receiving a complete petition. If a petition is under review by the department at the time an annual emissions report is due under WAC 173-441-140, the reporter must submit the emissions report using the quantification methods approved under this chapter at the time of submittal of the emissions report.

(b) **Content.** The petition must include, at a minimum, the following information to be considered a complete petition:

(i) Reporter identification information including reporter name(s), business name(s), business mailing address(es), and the Washington state Unified Business Identifier(s);

(ii) Location address, mailing address if different from the reporter address, North American Industrial Classification System (NAICS) primary and secondary codes, the EPA Facility Site ID (if applicable), and geographic coordinates of the site or sites where the reporter proposes to use the alternative quantification method;

(iii) A copy of the alternative quantification method, including the author(s), source of the method, the other greenhouse gas reporting programs that use the method, and whether the method meets the approval criteria described in subsection (2)(a) of this section;

(iv) A detailed analysis of how the alternative quantification method will provide reported emissions that are accurate, consistent, and comparable;

(v) A detailed description of which emissions will be covered by the proposed alternative quantification method and how emissions not covered by the proposed alternative quantification method will be calculated and reported;

(vi) Any other supporting data or information as requested by the department as described in subsection (2) of this section; and

(vii) The petition must be signed and dated by the designated representative.

(2) **Review of the petition by the department.** The alternative quantification method must be approved by the department prior to use by the reporter. The department will issue a determination within sixty days of receiving a complete petition.

(a) **Approval criteria.** In evaluating petitions for alternative quantification methods for approval, the department must consider whether the methods:

(i) Are established by a nationally or internationally recognized body in the field of greenhouse gas emissions reporting;

(ii) Were subject to public comment and peer review in their development; and

(iii) Calculate all sectors of greenhouse gas emissions required to be reported under RCW 70.94.151. In the event that a proposed alternative quantification method does not include a sector of required greenhouse gas emissions, e.g., calculation of indirect emissions, the reporter must use the quantification methods specified in subsection (4) of this section to calculate those emissions.

(b) **Approval of a petition to use quantification methods developed by the U.S. Environmental Protection Agency.** The department will approve a complete petition to use a quantification method in the U.S. Environmental Protection Agency's proposed rule, found in 40 CFR Part 98, as proposed at 74 Fed. Reg. 16447 (April 10, 2009). All other provisions within this section still apply, with the exception of subsection (1)(b)(iii) and (iv) of this section.

(3) **Report consistency.** After receiving approval of the petition by the department, the reporter is subject to the report consistency requirements of WAC 173-441-090 beginning with calendar year 2011 emissions reported in 2012.

(4) **Calculating emissions not included in alternative quantification method.** A reporter must report all sectors of greenhouse gas emissions for which reporting is required under RCW 70.94.151. If an approved alternative quantification method does not include quantification methods for sectors of emissions required to be reported under RCW 70.94.151, then the reporter must use a method described in WAC 173-441-100, 173-441-110, 173-441-500 through 173-441-800, 173-441-130(2), or approved for the reporter by the department in a separate petition to calculate and report those emissions.

(5) **Appeal of determination.** An approval or denial issued by the department in response to a written petition filed under this subsection is a determination appealable to the pollution control hearings board per RCW 43.21B.110 (1)(h).

<u>NEW SECTION</u>

WAC 173-441-130 Exclusion de minimis and simplified estimation methods. A reporter may use the following exclusion de minimis and simplified estimation methods when reporting its emissions.

(1) **Exclusion de minimis.** A reporter may choose not to report emissions from sites or units that meet the following requirements:

(a) **Site level exclusion de minimis.** A reporter may choose not to report emissions from any site with total emissions of greenhouse gases less than five metric tons of CO_2e. The five metric ton limit must be applied separately to direct emissions and indirect emissions.

(i) **Direct emissions.** A reporter may choose not to report direct emissions from any site with total direct emissions less than five metric tons of CO_2e per year.

(ii) **Indirect emissions.** A reporter may choose not to report indirect emissions from any site with total indirect emissions less than five metric tons of CO_2e per year.

(b) **Unit level exclusion de minimis.** A reporter may choose not to report emissions from the following emission units:

(i) **Stationary stand alone refrigeration units.** A reporter may choose not to report direct emissions from any stationary stand alone refrigeration unit with a combined refrigerator and freezer manufacturer rated capacity less than or equal to sixty cubic feet. Except, emissions from all refrigeration units that are carried on or moved by a mobile source capable of operating while in transit, connected to another refrigeration unit, or have had its refrigerant system serviced within the reporting year must be reported regardless of capacity.

(ii) **Stationary stand alone air conditioning units.** A reporter may choose not to report direct emissions from any stationary stand alone air conditioning unit with a manufacturer rated cooling capacity less than or equal to ten thousand Btus per hour. Except, emissions from all air conditioning units that are carried on or moved by a mobile source capable of operating while in transit, connected to another air conditioning unit, or have had its refrigerant system serviced within the reporting year must be reported regardless of capacity.

(2) **Simplified estimation methods.** A reporter may use simplified estimation methods to calculate emissions from one or more sources or greenhouse gases that do not exceed the limits established in (a) through (c) of this subsection. Simplified estimation methods are an alternative to the quantification methods specified in WAC 173-441-100, 173-441-110, or approved by the department pursuant to WAC 173-441-120, and permit a reporter to develop its own untiered quantification methodologies. Simplified estimation methods must use upper-bound assumptions that err on the side of overestimating rather than underestimating emissions.

(a) **Direct emissions.** A reporter may use simplified estimation methods for the direct emissions of one or more sources or greenhouse gases that collectively emit no more than five percent of its total direct emissions, expressed as CO_2e.

(b) **Indirect emissions.** A reporter may use simplified estimation methods for the indirect emissions of one or more sources or greenhouse gases that collectively emit no more than five percent of its total indirect emissions, expressed as CO_2e.

(c) **Combining simplified estimation methods from direct emissions and indirect emissions.** A reporter must account for direct emissions and indirect emissions separately when applying the five percent simplified estimation methods limit for sources or greenhouse gases. The combined total direct emissions and indirect emissions calculated using simplified estimation methods must not exceed ten thousand metric tons CO_2e.

(d) **Reporting.** The reporter must separately identify and include in the emissions report the emissions from sources calculated using simplified estimation methods.

NEW SECTION

WAC 173-441-140 Emissions reporting and certification schedule. The following emissions reporting and certification schedule applies to all reporters subject to the reporting requirements of this chapter.

(1) The designated representative must certify the greenhouse gas emissions report for any fleet of on-road motor vehicles or source or combination of sources meeting the applicable reporting threshold established in WAC 173-441-040. The designated representative must submit the certified report to the department by October 31st for the previous calendar year emissions, beginning in 2010 for 2009 calendar year emissions.

(2) **New emissions sources.** Owners or operators of new emissions sources that begin operations after January 1st of any calendar year must report emissions beginning with the first month of operation through the end of the first calendar year. Each subsequent annual emissions report must cover emissions for the full calendar year.

NEW SECTION

WAC 173-441-150 Report content and submission requirements. A reporter subject to the requirements of this chapter must submit an annual greenhouse gas emissions report, certified by the designated representative, to the department's registry of greenhouse gas emissions. The reporter must submit the emissions report according to the schedule established in WAC 173-441-140. Reporters must report emissions separately for each site, fleet of nonroad mobile sources, or fleet of on-road mobile vehicles. The department will accept a greenhouse gas emissions report only if the report is certified by the designated representative.

(1) **General information.** A reporter must report the following information for each site, fleet of nonroad mobile sources, or fleet of on-road motor vehicles:

(a) Reporter identification information including reporter name(s), business name(s), business mailing address(es), and the Washington state Unified Business Identifier(s);

(b) Designated representative contact name, mailing address, and telephone number(s);

(c) Identification information including the name of each site, fleet of nonroad mobile sources, fleet of on-road motor vehicles, and the associated North American Industrial Classification System (NAICS);

(d) An owner or operator with multiple sites, fleets of nonroad mobile sources, and/or fleets of on-road motor vehicles that are required to report under this chapter must report the emissions from all of these sources under one account. The account must include the corporate identification, including business name, mailing address, and business identifiers. The owner or operator must describe the organizational relationship between each site, fleet of nonroad mobile sources, and/or fleet of on-road motor vehicles;

(e) Name and contact information including mailing address and telephone number of the person primarily responsible for preparing the emissions report;

(f) Submittal information including reporting year and the date of submittal;

(g) Quantification methods employed for each source, including disclosure of all relevant assumptions made, data sources used, identification of any changes to the data, inventory boundary, and methods or other relevant factors relative to this or a prior-year report;

(h) Document if the reporter uses the exclusion de minimis provision in WAC 173-441-130(1);

(i) Identify sources and greenhouse gases calculated using simplified estimation methods and the resulting annual emissions quantities of each greenhouse gas, expressed in metric tons and CO_2e quantity expressed in metric tons; and

(j) A signed and dated certification statement provided by the designated representative.

(2) **Mobile sources.** A reporter must report the following information for mobile sources of emissions, in addition to the general reporting requirements under subsection (1) of this section:

(a) A reporter must report the following information for fleets of on-road motor vehicles:

(i) Fleet characteristic information and activity data including, but not limited to, fuel use and fuel type;

(ii) Annual greenhouse gas combustion emission quantities by fuel type or activity type, expressed in metric tons of each greenhouse gas. Emission quantities from biomass must be reported separately;

(iii) Annual greenhouse gas emission quantities of fugitive emissions expressed in metric tons of each greenhouse gas including, but not limited to, those from refrigeration, air conditioning, or other auxiliary units; and

(iv) Annual total emissions of greenhouse gases expressed in metric tons of CO_2e.

(b) A reporter of emissions from fleets of nonroad mobile sources operating beyond the boundaries of a single site must report total emissions of greenhouse gases from each fleet of nonroad mobile sources that is subject to the reporting requirements of this chapter. Emissions from each fleet of aircraft, fleet of marine vessels, and fleet of rail equipment must be reported separately. For each fleet of nonroad mobile sources identified, the reporter must report the following information:

(i) Fleet characteristic information and activity data including, but not limited to, fuel use and fuel type;

(ii) Annual greenhouse gas combustion emission quantities by fuel type or activity type, expressed in metric tons of each greenhouse gas. Emission quantities from biomass must be reported separately;

(iii) Annual greenhouse gas emission quantities of fugitive emissions expressed in metric tons of each greenhouse gas, including, but not limited to, those from refrigeration, air conditioning, or other auxiliary units;

(iv) Annual indirect emissions quantities of greenhouse gases, expressed in metric tons of CO_2e, associated with the purchase of electricity, steam, heating, or cooling; and

(v) Annual total emissions of greenhouse gases expressed in metric tons of CO_2e.

(c) A reporter of emissions from on-road motor vehicles, aircraft, or marine vessels operating exclusively within the boundaries of a site must report these emissions as part of the site. For all mobile sources operating exclusively within the boundaries of a single site, the reporter must report the following information:

(i) Mobile source characteristic information and activity data including, but not limited to, fuel use and fuel type;

(ii) Annual greenhouse gas combustion emission quantities by fuel type or activity type for the mobile source type expressed in metric tons of each greenhouse gas. Emission quantities from biomass must be reported separately;

(iii) Annual greenhouse gas emissions quantities of fugitive emissions expressed in metric tons of each greenhouse gas, including, but not limited to, those from refrigeration, air conditioning, or other auxiliary units;

(iv) Annual indirect emissions quantities of greenhouse gases, expressed in metric tons of CO_2e, associated with the purchase of electricity, steam, heating, or cooling;

(v) Annual total emissions of greenhouse gases expressed in metric tons of CO_2e; and

(vi) Identify the site in which the mobile source exclusively operates.

(3) **Stationary sources.** A reporter of stationary sources of emissions from a site must report total emissions of greenhouse gases from each site that is subject to the reporting requirements of this chapter. For each site identified, the reporter must report the following information in addition to the general reporting requirements under subsection (1) of this section:

(a) Location address, mailing address if different from the reporter address, North American Industrial Classification System (NAICS) primary and secondary codes, the EPA Facility Site ID (if applicable), and geographic coordinates;

(b) Activity data and measurement based data associated with direct emissions and indirect emissions;

(c) Annual quantities of emissions of each greenhouse gas by fuel type or activity type expressed in metric tons of each greenhouse gas. Emission quantities from biomass must be reported separately;

(d) Annual quantities of emissions of each greenhouse gas from combustion of fuels expressed in metric tons of CO_2e;

(e) Annual quantities of fugitive emissions of each greenhouse gas, expressed in metric tons of CO_2e;

(f) Annual quantities of process emissions of each greenhouse gas expressed in metric tons of CO_2e;

(g) Annual quantities of indirect emissions of greenhouse gases associated with the purchase of electricity, steam, heating, or cooling expressed in metric tons of CO_2e;

(h) Annual total greenhouse gas emission quantities expressed in metric tons of CO_2e; and

(i) Emissions data and other information specified in WAC 173-441-500 through 173-441-800, as applicable.

(4) **Submission of greenhouse gas emissions report.** The annual greenhouse gas emissions report must be submitted to the department's registry of greenhouse gas emissions in the format specified by the department.

(5) **Greenhouse gas emissions report revisions.** The reporter may revise a previously submitted emissions report under the circumstances specified in this section. The reporter must maintain documentation to support any revisions made to a previously submitted emissions report. Documentation for all emissions report revisions must be retained by the reporter for five years.

(a) If, after the report submittal is complete, a report is found to contain an error, or accumulation of errors, resulting in a material misstatement of reported emissions, the reporter must revise and resubmit an emissions report within thirty days of the finding. A revised report will be accepted only if approved by the department.

(b) If, after the report submittal is complete, a report is found to contain an error, or accumulation of errors, not resulting in a material misstatement of reported emissions, the reporter may revise and resubmit an emissions report within thirty days of the finding. A revised report will be accepted only if approved by the department.

(c) If a reporter makes a change in reporting methodologies that results in a change of five percent or larger in either the reporter's total direct emissions or total indirect emissions, expressed in metric tons of CO_2e, then the reporter must adjust emissions reports from previous years to account for the change in accordance with WAC 173-441-090. If the activity data needed to use the new method is not available for previous emission years, the reporter must clearly describe the change in methodology and document the lack of activity data in the emissions report, but is not required to recalculate emissions for previous years.

(d) All changes and documentation relating to previous emission years must be submitted as part of the current year's reporting activities.

(6) **Review of emissions reports by the department.** The department may review the certification statement, conduct a comprehensive review of the emissions report, perform audits of selected emissions sources, review other documents, and conduct

site inspections, as necessary, to ensure the completeness and accuracy of the reported greenhouse gas emissions.

NEW SECTION

WAC 173-441-160 Document retention and recordkeeping requirements. The reporter must establish and maintain procedures for document retention and recordkeeping. The reporter must retain all documents regarding the design, development, and maintenance of the greenhouse gas inventory in paper, electronic, or other usable format for a period of not less than five years following submission of each emissions report. The retained documents, including greenhouse gas emissions data, must be sufficient to allow for the review of each emissions report by the department.

(1) Upon request by the department the reporter must provide within thirty days all documents and data required to be retained under this section.

(2) In addition to information submitted as part of the emissions report, each reporter must retain, at a minimum, the following information for at least five years after the submission of the report:

(a) A list of all greenhouse gas sources (i.e., sites, fleets, operations, processes, and activities) included in the emission estimates;

(b) All activity data used to calculate emissions for each source, categorized by process and fuel or material type;

(c) Documentation of the process for collecting emissions data;

(d) Any greenhouse gas emissions calculations and quantification methods used;

(e) All emission factors used for emission estimates, including documentation for any factors not provided in this chapter;

(f) Documentation of biomass fractions for specific fuels;

(g) All other data submitted to the department under this chapter, including the greenhouse gas emissions report;

(h) All computations made to gap-fill missing data;

(i) Names and documentation of key facility personnel involved in emissions calculating and reporting;

(j) Any other information that is required for the department to conduct a review of the emissions report; and

(k) A log to be prepared for each reporting year, beginning January 1st, documenting all procedural changes made in greenhouse gas accounting methods and changes to instrumentation for greenhouse gas emissions estimation.

(3) For measurement based methodologies, the following information also must be retained for at least five years after the submission of the emissions report:

(a) List of all emission points monitored;

(b) Collected monitoring data;

(c) A detailed technical description of any continuous measurement systems, including documentation of any findings and approvals by federal, state, or local agencies;

(d) Raw and aggregated data from the continuous measurement system;

(e) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system; and

(f) Documentation of any changes in any continuous measurement systems over time.

(4) For sources required to use a method listed in WAC 173-441-500 through 173-441-800, a reporter must retain any additional information as required in the specific section.

NEW SECTION

WAC 173-441-170 Reporting fees. (1) **Fee determination.** Each reporter of emissions from an emissions source subject to this chapter must pay a reporting fee. The department must establish reporting fees based on workload using the process outlined below. The fees must be sufficient to cover the department's costs to administer the greenhouse gas emissions reporting program.

(2) **Fee eligible activities.** The costs of activities associated with administering this reporting program, as described in RCW 70.94.151(2), are fee eligible.

(3) **Workload analysis and budget development.** The department must conduct a workload analysis and develop a budget based on the process outlined below:

(a) **Workload analysis.** The department must conduct a workload analysis projecting resource requirements for administering the reporting program, organized by categories of fee-eligible activities, for the purpose of preparing the budget. The department must prepare the workload analysis for the two-year period corresponding to each biennium. The workload analysis must identify the fee-eligible administrative activities related to the reporting program that it will perform during the biennium and must estimate the resources required to perform these activities.

(b) **Budget development.** The department must prepare a budget for administering the reporting program for the two-year period corresponding to each biennium. The budget must be based on the resource requirements identified in the workload analysis for the biennium and must take into account the reporting program account balance at the start of the biennium.

(4) **Allocation methodology.** The department must allocate the reporting program budget among the reporters required to report greenhouse gas emissions under this chapter according to the

following components:

(a) **Flat component.** The flat component of a reporter's fee is calculated by the equal division of twenty percent of the budget amount by the total number of reporters in the greenhouse gas reporting program.

(b) **Emissions component.** The emissions component of the reporting fee applies only to the following reporters and is calculated using the following methodology:

(i) **Total emissions of greenhouse gases less than twenty-five thousand metric tons of CO_2e.** For a reporter of emissions from a source or combination of sources with total emissions of greenhouse gases reported of less than twenty-five thousand metric tons of CO_2e, the emissions component of the reporting fee is calculated by dividing thirty percent of the total budget amount by the total number of reporters in this category.

(ii) **Total emissions of greenhouse gases equal to or greater than twenty-five thousand metric tons of CO_2e.** For a reporter of emissions from a source or combination of sources with total emissions of greenhouse gases reported equal to or greater than twenty-five thousand metric tons of CO_2e, the emissions component of the reporting fee is calculated by dividing fifty percent of the total budget amount by the total number of reporters in this category.

(5) **Fleets of on-road motor vehicles.** The reporting fee for a reporter of emissions from a fleet of on-road motor vehicles required to report under this chapter includes only the flat component of the fee.

(6) **Source or combination of sources of emissions.** The reporting fee for a reporter of emissions from a source or combination of sources of emissions required to report under this chapter includes the flat component and the applicable emissions component of the fee. If a reporter reports emissions for a fleet of on-road motor vehicles and from sites or fleets of nonroad mobile sources, the reporter pays the flat component of the reporting fee only once.

(7) **Fee schedule.** The department must issue annually a fee schedule reflecting the administrative fee to be paid by each reporter. The fee schedule must be based on the budget and workload analysis conducted each biennium. The department must publish the fee schedule for the following year on or before October 31st of each year.

(8) **Fee payments.** Fees specified in this section must be paid within thirty days of receipt of the department's billing statement. All fees collected under this chapter must be made payable to the Washington department of ecology. A late fee surcharge of fifty dollars or ten percent of the fee, whichever is more, may be assessed for any fee not received after the thirty day period.

(9) **Dedicated account.** All reporting fees collected by the department must be deposited in the air pollution control account.

NEW SECTION

WAC 173-441-180 The department to share information with local air authorities and with the energy facility site evaluation council. (1) The department must share any reporting information reported to it under these rules with the local air authority in which the reporter operates.

(2) The department must share any information reported to it under these rules from facilities permitted by the energy facility site evaluation council with the council, including notice of a facility that has failed to report as required.

NEW SECTION

WAC 173-441-190 Enforcement. The department may take any of the following regulatory actions to enforce this chapter to meet the provisions of RCW 43.21B.300 which is incorporated by reference.

(1) **Enforcement for first-time violators.** The department will waive any fines or civil penalties for first-time reporting violations under this chapter.

(a) When the department waives a fine or penalty under this section, when possible it must require the reporter to correct the violation within a reasonable period of time, in a manner specified by the department. If correction is impossible, no correction may be required and failure to correct is not grounds for reinstatement of fines or penalties under this section.

(b) Exceptions to the waiver requirement of this section may be made if the reporter committing the violation owns or operates, or owned or operated a different emissions source which previously violated a reporting requirement under this chapter.

(c) Any fine or civil penalty that is waived under this section may be reinstated and imposed in addition to any additional fines or penalties associated with a subsequent violation for noncompliance with a reporting requirement under this chapter, or failure to correct the previous violation as required by the department in (a) of this subsection.

(2) **Enforcement actions by the department - notice to violators.** At least thirty days prior to the commencement of any formal enforcement action under RCW 70.94.430 and 70.94.431, the department shall cause written notice to be served upon the alleged violator or violators. The notice shall specify the provision of this chapter or the rule or regulation alleged to be violated, and the facts alleged to constitute a violation thereof, and may include an order that necessary corrective action be taken within a reasonable time. In lieu of an order, the department may require that the alleged violator or violators appear before it for the purpose of providing the department information pertaining to the

violation or the charges complained of. Every notice of violation shall offer to the alleged violator an opportunity to meet with the department prior to the commencement of enforcement action.

(3) **Civil penalties.** The department may impose a civil penalty on any reporter who violates the provisions of this chapter, as set forth below:

(a) In addition to or as an alternate to any other penalty provided by law, any reporter who violates any of the provisions of chapter 173-441 WAC may incur a civil penalty in an amount as set forth in RCW 70.94.431. Each such violation shall be a separate and distinct offense, and in case of a continuing violation, each day's continuance shall be a separate and distinct violation. Any person who fails to take action as specified by an order issued pursuant to this chapter shall be liable for a civil penalty as set forth by RCW 70.94.431 for each day of continued noncompliance.

(b) Penalties incurred but not paid shall accrue interest, beginning on the ninety-first day following the date that the penalty becomes due and payable, at the highest rate allowed by RCW 19.52.020 on the date that the penalty becomes due and payable. If violations or penalties are appealed, interest shall not begin to accrue until the thirty-first day following final resolution of the appeal. The maximum penalty amounts established in RCW 70.94.431 may be increased annually to account for inflation as determined by the state office of the economic and revenue forecast council.

(c) Each act of commission or omission which procures, aids, or abets in the violation shall be considered a violation under the provisions of this section and subject to the same penalty. The penalties provided in this section shall be imposed pursuant to RCW 43.21B.300.

(d) All penalties recovered under this section by the department shall be paid into the state treasury and credited to the air pollution control account established in RCW 70.94.015.

(e) Public or private entities that are recipients or potential recipients of the department grants, whether for air quality related activities or not, may have such grants rescinded or withheld by the department for failure to comply with provisions of this chapter.

(f) In addition to other penalties provided by this chapter, a reporter knowingly underreporting emissions or other information used to set fees, or a reporter required to pay emission or permit fees who is more than ninety days late with such payments may be subject to a penalty equal to three times the amount of the original fee owed.

(4) **Compliance orders.** The department may issue a compliance order in conjunction with a notice of violation. The order shall require the recipient of the notice of violation either to take necessary corrective action or to submit a plan for corrective action and a date when such action will be initiated.

(5) **Criminal penalties.** Any reporter who knowingly violates any of the provisions of this chapter is guilty of a gross misdemeanor and upon conviction thereof shall be punished by a fine of not more than ten thousand dollars, or by imprisonment in the

county jail for not more than one year, or by both for each separate violation.

NEW SECTION

WAC 173-441-200 Confidentiality. (1) Emissions data submitted to the department under this section are public information and must not be designated as confidential.

(2) Any reporter submitting information to the department pursuant to this chapter may request that information that is not emissions data be kept confidential as proprietary information under RCW 70.94.205 or because it is otherwise exempt from public disclosure under the Washington Public Records Act (chapter 42.56 RCW). All such requests for confidentiality must meet the requirements of RCW 70.94.205.

NEW SECTION

WAC 173-441-210 Severability. If any provision of the regulation or its application to any person or circumstance is held invalid, the remainder of the regulation or application of the provision to other persons or circumstances is not affected.

NEW SECTION

WAC 173-441-500 Natural gas extraction, processing, storage, transmission, and distribution. (1) **Definition of the source category.** This source category consists of the following facilities:

(a) Onshore natural gas processing facilities;

(b) Onshore natural gas transmission compression facilities;

(c) Natural gas transmission and distribution systems;

(d) Underground natural gas storage facilities;

(e) Liquefied natural gas storage facilities;

(f) Liquefied natural gas import and export facilities;

(2) Sources of GHGs to include in report;

(a) You must report CO_2 and CH_4 emissions in CO_2e metric tons per year from sources specified in (a)(i) through (xxv) of this subsection at onshore natural gas processing facilities, onshore natural gas transmission compression facilities, natural gas transmission and distribution systems, underground and above ground natural gas storage facilities, liquefied natural gas storage facilities and liquefied natural gas import and export facilities.

(i) Acid gas removal (AGR) vent stacks.

(ii) Blowdown vent stacks.

(iii) Centrifugal compressor dry seals.

(iv) Centrifugal compressor wet seals.

(v) Compressor fugitive emissions.

(vi) Compressor wet seal degassing vents.

(vii) Dehydrator vent stacks.

(viii) Flare stacks.

(ix) Liquefied natural gas import and export facilities fugitive emissions.

(x) Liquefied natural gas storage facilities fugitive emissions.

(xi) Natural gas driven pneumatic pumps.

(xii) Natural gas driven pneumatic manual valve actuator devices.

(xiii) Natural gas driven pneumatic valve bleed devices.

(xiv) Nonpneumatic pumps.

(xv) Offshore platform pipeline fugitive emissions.

(xvi) Open-ended lines (OELs).

(xvii) Pump seals.

(xviii) Platform fugitive emissions.

(xix) Processing facility fugitive emissions.

(xx) Reciprocating compressor rod packing.

(xxi) Storage station fugitive emissions.

(xxii) Storage tanks.

(xxiii) Storage wellhead fugitive emissions.

(xxiv) Transmission station fugitive emissions.

(xxv) Transmission and distribution pipeline inspection and maintenance activities.

(b) Emissions from combustion of natural gas or other fuels associated with above operations must be calculated per the methods in WAC 173-441-100(4).

(3) **Calculating GHG emissions**.

(a) Estimate emissions using either an annual direct measurement, as specified in subsection (4) of this section, or an engineering estimation method specified in this section. You may use the engineering estimation method only for sources for which a method is specified in this section.

(b) You may use engineering estimation methods described in this section to calculate emissions from the following fugitive emissions sources:

(i) Acid gas removal vent stacks;

(ii) Natural gas driven pneumatic pumps;

(iii) Natural gas driven pneumatic manual valve actuator devices;

(iv) Natural gas driven pneumatic valve bleed devices;

(v) Blowdown vent stacks;

(vi) Dehydrator vent stacks;

(vii) Natural gas pigging operations;

(viii) Pipeline maintenance and purging operations.

(c) A combination of engineering estimation described in this section and direct measurement described in subsection (4) of this section must be used to calculate emissions from the following fugitive emissions sources:

(i) Flare stacks;

(ii) Storage tanks;

(iii) Compressor wet seal degassing vents.

(d) You must use the methods described in subsection (4)(d) or (e) of this section to conduct annual leak detection of fugitive emissions from all sources listed in subsection (2)(a) of this section. If fugitive emissions are detected, engineering estimation methods may be used for sources listed in (b) and (c) of this subsection. If engineering estimation is used, emissions must be calculated using the appropriate method from (d)(i) through (ix) of this subsection:

(i) Acid gas removal vent stack. Calculate acid gas removal vent stack fugitive emissions using simulation software packages, such as ASPEN™ or AMINECalc™. Any standard simulation software may be used provided it accounts for the following parameters:

(A) Natural gas feed temperature, pressure, and flow rate;

(B) Acid gas content of feed natural gas;

(C) Acid gas content of outlet natural gas;

(D) Unit operating hours, excluding downtime for maintenance or standby;

(E) Exit temperature of natural gas;

(F) Solvent pressure, temperature, circulation rate and weight.

(ii) Natural gas driven pneumatic pump. Calculate fugitive emissions from a natural gas driven pneumatic pump as follows:

(A) Calculate fugitive emissions using manufacturer data.

(I) Obtain from the manufacturer specific pump model natural gas emission per unit volume of liquid pumped at operating pressures.

(II) Maintain a log of the amount of liquid pumped annually from individual pumps.

(III) Calculate the natural gas fugitive emissions for each pump using Equation 500.1 of this section.

$$E_{s,n} = F_s * V \qquad (Eq. 500.1)$$

Where:

$E_{s,n}$	=	Natural gas fugitive emissions at standard conditions.
F_s	=	Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at discharge pressure" units at standard conditions, as provided by the manufacturer.
V	=	Volume of liquid pumped annually.

(IV) Both CH_4 and CO_2 volumetric and mass fugitive emissions must be calculated from volumetric natural gas fugitive emissions using calculations in (f) and (g) of this subsection.

(B) If manufacturer data for F_s are not available, follow the method in subsection (4)(i)(i) of this section.

(iii) Natural gas driven pneumatic manual valve actuator devices. Calculate fugitive emissions from a natural gas driven pneumatic manual valve actuator device as follows:

(A) Calculate fugitive emissions using manufacturer data.

(I) Obtain from the manufacturer specific pneumatic device model natural gas emission per actuation.

(II) Maintain a log of the number of times the pneumatic device was actuated throughout the reporting period.

(III) Calculate the natural gas fugitive emissions for each manual valve actuator using Equation 500.2 of this section.

$$E_{s,n} = A_s * N \qquad (Eq. 500.2)$$

Where:

$E_{s,n}$	=	Natural gas fugitive emissions at standard conditions.
A_s	=	Natural gas driven pneumatic valve actuator natural gas emission in "emission per actuation" units at standard conditions, as provided by the manufacturer.
N	=	Number of times the pneumatic device was actuated in a way that vented natural gas to the atmosphere through the reporting period.

(IV) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in (f) and (g) of this subsection.

(B) Follow the method in subsection (4)(i)(ii) of this section if manufacturer data are not available.

(iv) Natural gas driven pneumatic valve bleed devices. Calculate fugitive emissions from a natural gas driven pneumatic valve bleed device as follows:

(A) Calculate fugitive emissions using manufacturer data.

(I) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(II) Calculate the natural gas fugitive emissions for each valve bleed device using Equation 500.3 of this section.

$$E_{s,n} = B_s * T \qquad (Eq. 500.3)$$

Where:

$E_{s,n}$	=	Natural gas fugitive emissions at standard conditions.
B_s	=	Natural gas driven pneumatic device bleed rate in "emission per unit time" units at standard conditions, as provided by the manufacturer.

T = Amount of time the pneumatic device has been operational through the reporting period.

(III) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in (f) and (g) of this subsection.

(B) Follow the method in subsection (4)(i)(iii) of this section if manufacturer data are not available.

(v) Blowdown vent stacks. Calculate fugitive emissions from blowdown vent stacks as follows:

(A) Calculate the total volume (including, but not limited to, pipelines and vessels) between isolation valves (V_v in Equation 500.4 of this section).

(B) Retain logs of the number of blowdowns for each equipment type.

(C) Calculate the total annual fugitive emissions using the following Equation 500.4 of this section.

$$E_{a,n} = N * V_v \qquad (Eq. 500.4)$$

Where:

$E_{s,n}$ = Natural gas fugitive emissions at ambient conditions from blowdowns.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves.

(D) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in (e) of this subsection.

(E) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in (f) and (g) of this subsection.

(vi) Dehydrator vent stacks. Calculate fugitive emissions from a dehydrator vent stack using a simulation software package, such as GLYCalc™. Any standard simulation software may be used provided it accounts for the following parameters:

(A) Feed natural gas flow rate;

(B) Feed natural gas water content;

(C) Outlet natural gas water content;

(D) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric);

(E) Absorbent circulation rate;

(F) Absorbent type: Including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG);

(G) Use of stripping natural gas;

(H) Use of flash tank separator (and disposition of recovered gas);

(I) Hours operated; and

(J) Wet natural gas temperature, pressure, and composition.

(vii) Flare stacks. Calculate fugitive emissions from a flare stack as follows:

(A) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is ninety-five percent for nonsteam aspirated flares and ninety-eight percent for steam aspirated or air injected flares.

(B) Calculate volume of natural gas sent to flare from velocity measurement in subsection (4)(j) of this section using manufacturer's manual for the specific meter used to measure velocity.

(C) Calculate GHG volumetric fugitive emissions at actual conditions using Equation 500.5 of this section.

$$E_{a,i} = V_a * (1 - \eta) * X_i + (1 - K) * \eta * V_a * Y_j * R_{j,i} \qquad (Eq. 500.5)$$

Where:

$E_{a,i}$	=	Annual fugitive emissions from flare stack.
V_a	=	Volume of natural gas sent to flare stack determined from subsection (4)(j)(i) of this section.
η	=	Percent of natural gas combusted by flare (default is 95 percent for nonsteam aspirated flares and 98 percent for steam aspirated or air injected flares).
X_i	=	Concentration of GHG i in the flare gas determined from subsection (4)(j)(i) of this section.
Y_j	=	Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus).
$R_{j,i}$	=	Number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).
K	=	"1" when GHG i is CH_4 and "0" when GHG i is CO_2.

(D) Calculate GHG volumetric fugitive emissions at standard conditions using Equation 500.6 of this section.

$$E_{s,i} = \frac{E_{a,i} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad (Eq. 500.6)$$

Where:

$E_{s,i}$	=	Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.
$E_{a,i}$	=	Natural gas volumetric fugitive emissions at actual conditions.

T_s	=	Temperature at standard conditions (°F).
T_a	=	Temperature at actual emission conditions (°F).
P_s	=	Absolute pressure at standard conditions (inches of Hg).
P_a	=	Absolute pressure at ambient conditions (inches of Hg).

(E) Calculate both CH_4 and CO_2 mass fugitive emissions from volumetric CH_4 and CO_2 fugitive emissions using calculations in (g) of this subsection.

(viii) Storage tanks. Calculate fugitive emissions from a storage tank as follows:

(A) Calculate the total annual hydrocarbon vapor fugitive emissions using Equation 500.7 of this section.

$$E_{a,h} = Q * ER \qquad (Eq. 500.7)$$

Where:

$E_{a,h}$	=	A hydrocarbon vapor fugitive emissions at actual conditions.
Q	=	Storage tank total annual throughput.
ER	=	Measured hydrocarbon vapor emissions rate per throughput (e.g., cubic feet/barrel) determined from subsection (4)(j)(ii) of this section.

(B) Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in (e) of this subsection.

(C) Estimate CH_4 and CO_2 volumetric fugitive emissions from volumetric hydrocarbon fugitive emissions using Equation 500.8 of this section.

$$E_{s,i} = E_{s,h} * M_i \qquad (Eq. 500.8)$$

Where:

$E_{s,i}$	=	GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.
$E_{s,h}$	=	Hydrocarbon vapor volumetric fugitive emissions at standard conditions.
M_i	=	Mole percent of a particular GHG i in the hydrocarbon vapors; hydrocarbon vapor analysis must be conducted in accordance with ASTM D1945-03.

(D) Estimate CH_4 and CO_2 mass fugitive emissions from GHG volumetric fugitive emissions using calculations in (g) of this subsection.

(ix) Compressor wet seal degassing vents. Calculate fugitive emissions from compressor wet seal degassing vents as follows:

(A) Calculate volume of natural gas sent to vent from velocity measurement in subsection (4)(j) of this section using manufacturer's manual for the specific meter used to measure velocity.

(B) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in (e) of this subsection.

(C) Calculate both CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in (f) and (g) of this subsection.

(e) Calculate natural gas volumetric fugitive emissions at standard conditions by converting ambient temperature and pressure of natural gas fugitive emissions to standard temperature and pressure of natural gas using Equation 500.9 of this section.

$$E_{s,n} = \frac{E_{a,n} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad (Eq. 500.9)$$

Where:

$E_{s,n}$	=	Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.
$E_{a,n}$	=	Natural gas volumetric fugitive emissions at actual conditions.
T_s	=	Temperature at standard conditions (°F).
T_a	=	Temperature at actual emission conditions (°F).
P_s	=	Absolute pressure at standard conditions (inches of Hg).
P_a	=	Absolute pressure at ambient conditions (inches of Hg).

(f) Calculate GHG volumetric fugitive emissions at standard conditions as specified in (f)(i) and (ii) of this subsection.

(i) Estimate CH_4 and CO_2 fugitive emissions from natural gas fugitive emissions using Equation 500.10 of this section.

$$E_{s,i} = E_{s,n} * M_i \qquad (Eq. 500.10)$$

Where:

$E_{s,i}$	=	GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.
$E_{s,n}$	=	Natural gas volumetric fugitive emissions at standard conditions.
M_i	=	Mole percent of GHG i in the natural gas.

(ii) For Equation 500.10 of this section, the mole percent, Mi, must be the annual average mole percent for each facility, as specified in (f)(ii)(A) through (G) of this subsection.

(A) GHG mole percent in produced natural gas for offshore petroleum and natural gas production facilities.

(B) GHG mole percent in feed natural gas for all fugitive emissions sources upstream of the demethanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all fugitive emissions sources downstream of the demethanizer for onshore natural gas processing facilities.

(C) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(D) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(E) GHG mole percent in natural gas stored in LNG storage facilities.

(F) GHG mole percent in natural gas stored in LNG import and export facilities.

(G) GHG mole percent in transmission pipeline natural gas that is passed to a natural gas distribution system.

(g) Calculate GHG mass fugitive emissions at standard conditions by converting the GHG volumetric fugitive emissions into mass fugitive emissions using Equation 500.11 of this section.

$$\boldsymbol{Mass_{s,i} = E_{s,i} * \rho_i} \qquad (\boldsymbol{Eq.\,500.11})$$

Where:

$Mass_{s,i}$	=	GHG i (either CH_4 or CO_2) mass fugitive emissions at standard conditions.
$E_{s,i}$	=	GHG i (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions.
ρ_i	=	Density of GHG i; 1.87 kg/m^3 for CO_2 and 0.68 kg/m^3 for CH_4.

(h) Emissions from gas transmission and distribution lines from line maintenance operations.

(i) Emissions CH_4 and CO_2 as a result of pipeline cleaning and inspection with pigs must be estimated based on the volume of gas required to insert the pig at the pig injection station plus the volume required to eject the pig from the pipeline at pig retrieval stations. The CH_4 and CO_2 emissions must be based on the measured mole fractions of CH_4 and CO_2 content measured per subsection (4)(j)(i)(C) of this section.

(ii) Emissions of CH_4 and CO_2 as a result of pipe maintenance that requires a pipe segment to be purged of natural gas. These emissions must be calculated based on the volume of the pipe between shut off valves the pressure of the gas inside the pipe at the time of purging, and the mole fractions of the natural gas CH_4 and CO_2 content measured per subsection (4)(j)(i)(C) of this section.

(i) Converting mass of CH_4 and CO_2 emitted to CO_2e.

$$CO_{2e} = 21 * Mass_{CH4} + Mass_{CO2} \qquad (Eq.\,500.12)$$

Where:

CO_2e	=	Total metric tonnes of CH_4 and CO_2 expressed as carbon dioxide equivalent.
$Mass_{CH4}$	=	The mass in metric tons of CH_4 contained in the gas emitted from all units and sources covered in this section.
$Mass_{CO2}$	=	The mass in metric tons of CO_2 contained in the gas emitted from all units and sources covered in this section.
21	=	Global warming potential of CH_4.

(4) **Monitoring and QA/QC requirements.**

(a) You must use the methods described in (d) or (e) of this subsection to conduct annual leak detection of fugitive emissions from all sources listed in subsection (2)(a) of this section, whether in operation or on standby. If fugitive emissions are detected for sources listed in (b) of this subsection, you must use the measurement methods described in (c) of this subsection to measure emissions from each source with fugitive emissions.

(b) You must use detection instruments described in (d) and (e) of this subsection to monitor the following fugitive emissions:

(i) Centrifugal compressor dry seals fugitive emissions;

(ii) Centrifugal compressor wet seals fugitive emissions;

(iii) Compressor fugitive emissions;

(iv) LNG import and export facility fugitive emissions;

(v) LNG storage station fugitive emissions;

(vi) Nonpneumatic pumps fugitive emissions;

(vii) Open-ended lines (OELs) fugitive emissions;

(viii) Pump seals fugitive emissions;

(ix) Offshore platform pipeline fugitive emissions;

(x) Platform fugitive emissions;

(xi) Processing facility fugitive emissions;

(xii) Reciprocating compressor rod packing fugitive emissions;

(xiii) Storage station fugitive emissions;

(xiv) Transmission station fugitive emissions; and

(xv) Storage wellhead fugitive emissions.

(c) You must use a high volume sampler, described in (f) of this subsection, to measure fugitive emissions from the sources detected in (b) of this subsection, except as provided in (c)(i) and (ii) of this subsection:

(i) Where high volume samplers cannot capture all of the fugitive emissions, you must use calibrated bags described in (g) of this subsection or meters described in (h) of this subsection to measure the following fugitive emissions:

(A) Open-ended lines (OELs);

(B) Centrifugal compressor dry seals fugitive emissions;

(C) Centrifugal compressor wet seals fugitive emissions;

(D) Compressor fugitive emissions;

(E) Pump seals fugitive emissions;

(F) Reciprocating compressor rod packing fugitive emissions; and

(G) Flare stacks and storage tanks, except that you must use meters in combination with engineering estimation methods to calculate fugitive emissions.

(ii) Use hot wire anemometer to calculate fugitive emissions from centrifugal compressor wet seal degassing vents and flares where it is unsafe or too high a flow rate to use calibrated bags.

(d) Infrared remote fugitive emissions detection.

(i) Use infrared fugitive emissions detection instruments that can identify specific equipment sources as emitting. Such instruments must have the capability to trace a fugitive emission back to the specific point where it escapes the process and enters the atmosphere.

(ii) If you are using instruments that visually display an image of fugitive emissions, you must inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions at least once annually.

(iii) If you are using any other infrared detection instruments, such as those based on infrared laser reflection, you must monitor all potential emission points at least once annually.

(iv) Perform fugitive emissions detection under favorable conditions, including, but not limited to, during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument.

(v) Use fugitive emissions detection and measurement instrument manuals to determine optimal operating conditions.

(e) Use organic vapor analyzers (OVAs) for all fugitive emissions detection that are safely accessible at close-range.

(i) Check each potential emissions source, all joints, connections, and other potential paths to the atmosphere for emissions.

(ii) Evaluate the lag time between the instrument sensing and alerting caused by the residence time of a sample in the probe must be evaluated; upon alert, the instrument must be slowly retraced over the source to pinpoint the location of fugitive emissions.

(iii) Use Method 21 of 40 CFR Part 60, Appendix A, Determination of Volatile Organic Compound Leaks to calibrate OVAs.

(f) Use a high volume sampler to measure only cold and steady emissions within the capacity of the instrument.

(i) A trained technician must conduct measurements. The technician must be conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, including, but not limited to, positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(ii) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you must use antistatic wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(iii) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in subsection (3)(f) and (g) of this section.

(iv) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(g) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and the entire fugitive emissions volume can be captured for measurement.

(i) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag.

(ii) Perform three measurements of the time required to fill the bag; report the emissions as the average of the three readings.

(iii) Estimate natural gas volumetric emissions at standard conditions using calculations in subsection (3)(e) of this section.

(iv) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in subsection (3)(f) and (g) of this section.

(v) Obtain consistent results when measuring the time it takes to fill the bag with fugitive emissions.

(h) Channel all emissions from a single source directly through the meter when using metering (e.g., rotameters, turbine meters, and others).

(i) Use an appropriately sized meter so that the flow does not exceed the full range of the meter in the course of measurement and conversely has sufficient momentum for the meter to register continuously in the course of measurement.

(ii) Estimate natural gas volumetric fugitive emissions at standard conditions using calculations in subsection (3)(f) of this section.

(iii) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in subsection (3)(f) and (g) of this section.

(iv) Calibrate the meter using either one of the two methods provided as follows:

(A) Develop calibration curves by following the manufacturer's instruction.

(B) Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST). Determine correction factors for the flow meter according to the manufacturer's instructions. Record deviations from the correct reading at several flow rates. Plot the data points, comparing the flowmeter output to the actual flow rate as determined by the master weigh scale and use the difference as a correction factor.

(i) Where engineering estimation as described in subsection (3) of this section is not possible, use direct measurement methods as follows:

(i) If manufacturer data on pneumatic pump natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids. Determine the volume of liquid being pumped from the manufacturer's manual to provide the amount of natural gas emitted per unit of liquid pumped.

(A) Record natural gas conditions (temperature and pressure) and convert natural gas emission per unit volume of liquid pumped at actual conditions into natural gas emission per pumping cycle at standard conditions using Equation 500.9 of subsection (3) of this section.

(B) Calculate annual fugitive emissions from the pump using Equation 500.1 of this section, by replacing the manufacturer's data on emission (variable F_s) in the equation with the standard conditions natural gas emission calculated in (i)(i)(A) of this subsection.

(C) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in subsection (3)(f) and (g) of this section.

(ii) If manufacturer data on pneumatic manual valve actuator device natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per actuation using a calibrated bag for each pneumatic device per actuation.

(A) Record natural gas conditions (temperature and pressure) and convert natural gas emission at actual conditions into natural gas emission per actuation at standard conditions using Equation 500.9 of this section.

(B) Calculate annual fugitive emissions from the pneumatic device using Equation 500.2 of this section, by replacing the manufacturer's data on emission (variable A_s) in the equation with the standard conditions natural gas emission calculated in (i)(ii)(A) of this subsection.

(C) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas fugitive emissions using the calculations in subsection (3)(f) and (g) of this section.

(iii) If manufacturer data on natural gas driven pneumatic valve bleed rate is not available, conduct a one-time measurement to determine natural gas bleed rate using a high volume sampler or calibrated bag or meter for each pneumatic device.

(A) Record natural gas conditions (temperature and pressure) to convert natural gas bleed rate at actual conditions into natural gas bleed rate at standard conditions using Equation 500.9 of this section.

(B) Calculate annual fugitive emissions from the pneumatic device using Equation 500.3 of this section, by replacing the manufacturer's data on bleed rate (variable B) in the equation with the standard conditions bleed rate calculated in (i)(iii)(A) of this subsection.

(C) Estimate CH_4 and CO_2 volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in subsection (3)(f) and (g) of this section.

(j) Parameters for calculating emissions from flare stacks, compressor wet seal degassing vents, transmission and distribution system maintenance activities, and storage tanks.

(i) Estimate fugitive emissions from flare stacks and compressor wet seal degassing vents as follows:

(A) Insert flow velocity measuring device (such as hot wire anemometer or pitot tube) directly upstream of the flare stack or compressor wet seal degassing vent to determine the velocity of gas sent to flare or vent.

(B) Record actual temperature and pressure conditions of the gas sent to flare or vent.

(C) Sample representative gas to the flare stack or compressor wet seal degassing vent every quarter to evaluate the composition of GHGs present in the stream. Record the average of the most recent four gas composition analyses, which must be conducted using ASTM D1945-03.

(ii) Estimate fugitive emissions from storage tanks as follows:

(A) Measure the hydrocarbon vapor emissions from storage tanks using a flow meter described in (h) of this subsection for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.

(B) Record the net (related to working loss) and gross (related to flashing loss) input of the storage tank during the test period.

(C) Record temperature and pressure of hydrocarbon vapors emitted during the test period.

(D) Collect a sample of hydrocarbon vapors for composition analysis.

(k) Component fugitive emissions sources that are not safely accessible within the operator's arm's reach from the ground or stationary platforms are excluded from the requirements of this section.

(l) Determine annual emissions assuming that the fugitive emissions were continuous from the beginning of the reporting period or last recorded zero detection in the current reporting period and continuing until the fugitive emissions is repaired.

(5) **Data reporting requirements.** In addition to the information required by WAC 173-441-150, each annual report must report emissions data as specified in this section.

(a) Annual emissions reported separately for each of the operations listed in (a)(i) through (vi) of this subsection. Within each operation, emissions from each source type must be reported in the aggregate. For example, an underground natural gas storage facility with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(i) Offshore petroleum and natural gas production facilities.

(ii) Onshore natural gas processing facilities.

(iii) Onshore natural gas transmission compression facilities.

(iv) Underground natural gas storage facilities.

(v) Liquefied natural gas storage facilities.

(vi) Liquefied natural gas import and export facilities.

(b) Emissions reported separately for standby equipment.

(c) Emissions calculated for these sources must assume no CO_2 capture and transfer offsite.

(d) Activity data for each aggregated source type level for which emissions are being reported.

(e) Engineering estimate of total component count.

(f) Total number of compressors and average operating hours per year for compressors for each operation listed in (a)(i) of this subsection through subsection (6) of this section.

(g) Minimum, maximum, and average throughout for each operation listed in (a)(i) through (vi) of this subsection.

(h) Specification of the type of any control device used, including flares, for any source type listed in subsection (2)(a) of this section.

(i) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both.

(j) Detection and measurement instruments used.

(6) **Definitions.** All terms used in this section have the meaning given in WAC 173-441-030 and the Washington Clean Air Act unless defined below.

"Air injected flare" means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high noncombustible component content).

"Bleed rate" means the rate at which natural gas flows continuously or intermittently from a process measurement instrument to a valve actuator controller where it is vented (bleeds) to the atmosphere.

"Blowdown" means manual or automatic opening of valves to relieve pressure and/or release natural gas from, but not limited to, process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance.

"Blowdown vent stack fugitive emissions" means natural gas released due to maintenance and/or blowdown operations including, but not limited to, compressor blowdown and emergency shutdown system testing.

"Boil-off gas" means natural gas that vaporizes from liquefied natural gas in storage tanks.

"Centrifugal compressor" means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

"Centrifugal compressor dry seals" means a series of rings that are located around the compressor shaft where it exits the compressor case and that operate mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

"Centrifugal compressor dry seals fugitive emissions" means natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

"Centrifugal compressor wet seals" means a series of rings around the compressor shaft where it exits the compressor case, that use oil circulated under high pressure between the rings to prevent natural gas from escaping to the atmosphere.

"Centrifugal compressor wet seals fugitive emissions" means natural gas released from the seal face around the rotating shaft where it exits one or both ends of the compressor case PLUS the natural gas absorbed in the circulating seal oil and vented to the atmosphere from a seal oil degassing vessel or sump before the oil is recirculated, or from a seal oil containment vessel vent.

"Component," for the purposes of this section only, means but is not limited to each metal to metal joint or seal of nonwelded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

"Compressor" means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas (i.e., compression ratio higher than 1.5).

"Compressor fugitive emission" means natural gas emissions from all components in close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates, including, but not limited to, open-ended blowdown vent stacks, piping and tubing connectors and flanges, pressure relief valves, pneumatic starter open-ended lines, instrument connections, cylinder valve covers, and fuel valves.

"Condensate" means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

"Connector" means but is not limited to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "Ts" or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

"Dehydrator" means, for the purposes of this rule, a device in which a liquid absorbent (including, but not limited to, desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

"Dehydrator vent stack fugitive emissions" means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

"Demethanizer" means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (ethane, propane, butane, pentane-plus) in feed natural gas stream.

"Engineering estimation" means an estimate of fugitive emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

"Equipment" means but is not limited to each pump, compressor, pipe, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, tank, vessel, and instrumentation system in natural gas or liquid service; and any control devices or systems referenced by this subpart.

"Equipment chambers" means the total natural gas-containing volume within any equipment and between the equipment isolation valves.

"Export" means to transport a product from inside Washington state to persons outside Washington state, excluding United States military bases and ships for onboard use.

"Exporter" means any person, company, or organization of record that contracts to transfer a product from Washington state to another state or country or that transfers products to an affiliate in another state or country, excluding transfers to United States military bases and ships for onboard use.

"Flare" means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

"Flare combustion efficiency" means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip, assumed ninety-five percent for nonaspirated field flares and ninety-eight percent for steam or air aspirated flares.

"Flare stack" means a device used to provide a safe means of combustible natural gas disposal from routine operations, upsets, or emergencies via combustion of the natural gas in an open, normally elevated flame.

"Flare stack fugitive emissions" means the CH_4 and CO_2 content of that portion of natural gas (typically five percent in nonaspirated field flares and two percent in steam or air aspirated flares) that passes through flares uncombusted and the total CO_2 emissions of that portion of the natural gas that is combusted.

"Fugitive emissions" means unintentional equipment emissions of methane and/or carbon dioxide containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. Fugitive emissions also mean CO_2 emissions resulting from combustion of natural gas in flares.

"Gas conditions" means the actual temperature, volume, and pressure of a gas sample.

"Gathering and boosting station" means a station used to gather natural gas from well or field pipelines for delivery to natural gas processing facilities or a central point. Stations may also provide compression, dehydration, and/or treating services.

"Importer" means any person, company, or organization of record that for any reason brings a product (natural gas or LNG) into the United States from a foreign country. An importer includes the person, company, or organization primarily liable for the payment of any duties on the merchandise or an authorized agent acting on their behalf. The term also includes, as appropriate:

(a) The consignee.

(b) The importer of record.

(c) The actual owner.

(d) The transferee, if the right to draw merchandise in a bonded warehouse has been transferred.

"Infrared remote fugitive emissions detection instrument" means an instrument that detects infrared light in the narrow wavelength range absorbed by light hydrocarbons including methane, and presents a signal (sound, digital, or visual image) indicating the presence of methane and other light hydrocarbon vapor emissions in the atmosphere. For the purpose of this rule, it must detect the presence of methane.

"Interstate pipeline" means a natural gas pipeline designated as interstate pipelines under the Natural Gas Act, 15 U.S.C. § 717a.

"Intrastate pipeline" means a natural gas pipeline not subject to the jurisdiction of the Federal Energy Regulatory Commission as described in 15 U.S.C. § 3301.

"Liquefied natural gas (LNG)" means natural gas (primarily methane) that has been liquefied by reducing its temperature to −260°F at atmospheric pressure.

"Liquefied natural gas import and export facilities" means onshore and/or offshore facilities that send out exported or receive imported liquefied natural gas, store it in storage tanks, regasify it, and deliver regasified natural gas to natural gas transmission or distribution systems. The facilities include tanker unloading equipment, liquefied natural gas transportation pipelines, pumps, compressors to liquefy boil-off-gas, recondensers, and vaporization units for regasification of the liquefied natural gas.

"Liquefied natural gas storage facilities" means an onshore facility that stores liquefied natural gas in above ground storage vessels. The facility may include equipment for liquefying natural gas, compressors to liquefy boil-off-gas, recondensers, and vaporization units for regasification of the liquefied natural gas.

"LNG import and export facility fugitive emissions" means natural gas releases from valves, connectors, storage tanks, flanges, open-ended lines, pressure relief valves, boil-off-gas recovery, send outs (pumps and vaporizers), packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

"LNG storage station fugitive emissions" means natural gas releases from valves, connectors, flanges, open-ended lines, storage tanks, pressure relief valves, liquefaction process units, packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

"Mcf" means thousand cubic feet.

"Natural gas" means a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this section, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

"Natural gas distribution system" means the natural gas piping system between the gas distribution pressure let-down metering and regulating stations and the customer's gas meter. The distribution network includes all valves, pressure regulating stations, compression stations, and natural gas distribution fugitive emission sources.

"Natural gas driven pneumatic manual valve actuator device" means valve control devices that use pressurized natural gas to provide the energy required for an operator to manually open, close, or throttle a liquid or gas stream. Typical manual control applications include, but are not limited to, equipment isolation valves, tank drain valves, pipeline valves.

"Natural gas driven pneumatic manual valve actuator device fugitive emissions" means natural gas released due to manual actuation of natural gas pneumatic valve actuation devices, including, but not limited to, natural gas diaphragm and pneumatic-hydraulic valve actuators.

"Natural gas driven pneumatic pump" means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

"Natural gas driven pneumatic pump fugitive emissions" means natural gas released from pumps that are powered or assisted by pressurized natural gas.

"Natural gas driven pneumatic valve bleed device" means valve control devices that use pressurized natural gas to transmit a process measurement signal to a valve actuator to automatically control the valve opening. Typical bleeding process control applications include, but are not limited to, pressure, temperature, liquid level, and flow rate regulation.

"Natural gas driven pneumatic valve bleed devices fugitive emissions" means the continuous or intermittent release of natural gas from automatic process control loops including the natural gas pressure signal flowing from a process measurement instrument (e.g., liquid level, pressure, temperature) to a process control instrument which activates a process control valve actuator.

"Natural gas liquids (NGL)" means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally, such liquids consist of primarily ethane, propane, butane, and isobutane, primarily pentanes produced from natural gas at lease separators and field facilities. For the purposes of subpart NN only, natural gas liquids does not include lease condensate. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

"Natural gas processing facilities" is engaged in the extraction of natural gas liquids from produced natural gas;

fractionation of mixed natural gas liquids to natural gas products; and removal of carbon dioxide, sulfur compounds, nitrogen, helium, water, and other contaminants. Natural gas processing facilities also encompass gathering and boosting stations that include equipment to phase-separate natural gas liquids from natural gas, dehydrate the natural gas, and transport the natural gas to transmission pipelines or to a processing facility.

"Natural gas products" means products produced for consumers from natural gas processing facilities including, but not limited to, ethane, propane, butane, isobutane, and pentanes-plus.

"Natural gas transmission compression facility" means any permanent combination of compressors that move natural gas at increased pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage facilities. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and storage of water and hydrocarbon liquids.

"NIST" means the United States National Institute of Standards and Technology.

"Nonsteam aspirated flare" means a flare where natural gas burns at the tip with natural induction of air (and relatively lower combustion efficiency as may be evidenced by smoke formation).

"Offshore" means tidal-affected borders of the U.S. lands, both state and federal, adjacent to oceans, bays, lakes or other normally standing water.

"Offshore petroleum and natural gas production facilities" means any platform structure, floating in the ocean or lake, fixed on ocean or lake bed, or located on artificial islands in the ocean or lake, that houses equipment to extract hydrocarbons from ocean floor and transports it to storage or transport vessels or onshore. In addition, offshore production facilities may include equipment for separation of liquids from natural gas components, dehydration of natural gas, extraction of H_2S and CO_2 from natural gas, crude oil and condensate storage tanks, both on the platform structure and floating storage tanks connected to the platform structure by a pipeline, and compression or pumping of hydrocarbons to vessels or onshore. The facilities under consideration are located in both state administered waters and mineral management services administered federal waters.

"Offshore platform pipeline fugitive emissions" means natural gas above the water line released from piping connectors, pipe wall ruptures and holes in natural gas and crude oil pipeline surfaces on offshore production facilities.

"Open-ended line fugitive emissions" means natural gas released from pipes or valves open on one end to the atmosphere that are intended to periodically vent or drain natural gas to the atmosphere but may also leak process gas or liquid through incomplete valve closure including valve seat obstructions or damage.

"Open-ended valve or lines (OELs)" means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid (such as pressurized natural gas) and one side open to atmosphere, either directly or through open piping.

"Organic vapor analyzer (OVA)" means an organic monitoring device that uses a flame ionization detector to measure the concentrations in air of combustible organic vapors from 9 to 10,000 parts per million sucked into the probe.

"Platform fugitive emissions" means natural gas released from equipment and equipment components including valves, pressure relief valves, connectors, tube fittings, open-ended lines, ports, and hatches. This does not include fugitive emissions from equipment and components reported elsewhere for this rule.

"Processing facility fugitive emissions" means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shutdown) system fugitive emissions, packing and gaskets in natural gas processing facilities. This does not include fugitive emissions from equipment and components reported elsewhere for this rule, such as compressor fugitive emissions; acid gas removal, blowdown, wet seal oil degassing, and dehydrator vents; and flare stacks.

"Production process unit" means equipment used to capture a carbon dioxide stream.

"Pump seals" means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

"Pump seal fugitive emissions" means natural gas released from the seal face between the pump internal chamber and the atmosphere.

"Reciprocating compressor" means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

"Reciprocating compressor rod packing" means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

"Reciprocating compressor rod packing fugitive emissions" means natural gas released from a connected tubing vent and/or around a piston rod where it passes through the rod packing case. It also includes emissions from uncovered distance piece, rod packing flange (on each cylinder), any packing vents, cover plates (on each cylinder), and the crankcase breather cap.

"Recondenser" means heat exchangers that cool compressed boil-off-gas to a temperature that will condense natural gas to a liquid.

"Regasification" means the process of vaporizing liquefied natural gas to gaseous phase natural gas.

"Sour natural gas" means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

"Standard conditions or standard temperature and pressure

(STP)" means 60°F and 14.7 pounds per square inch absolute.

"Steam aspirated flare" means steam injected into the flare burner tip to induce air mixing with the hydrocarbon fuel to promote more complete combustion as indicated by lack of smoke formation.

"Storage station fugitive emissions" means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shutdown) system emissions, packing and gaskets in natural gas storage station. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

"Storage tank fugitive emissions" means natural gas vented when it flashes out of liquids; this occurs when liquids are transferred from higher pressure and temperature conditions upstream, plus working losses from liquid level increases and decreases during filling and draining and standing losses (breathing losses) from diurnal temperature changes and barometric pressure changes expanding and contracting the vapor volume of a tank.

"Storage wellhead fugitive emissions" means natural gas released from storage station wellhead components including, but not limited to, valves, OELs, connectors, flanges, and tube fittings.

"Subsurface" or "subsurface facility" means for the purposes of this rule, a natural gas facility, such as a pipeline and metering and regulation station in a closed vault below the land surface of the earth.

"Tanker unloading" means pumping of liquid hydrocarbon (e.g., crude oil, LNG) from an ocean-going tanker or barge to shore storage tanks.

"Transmission compressor station fugitive emissions" means natural gas released from all components including, but not limited to, valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shutdown) system emissions, packing and gaskets in natural gas transmission compressor stations. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule, such as compressor fugitive emissions.

"Transmission pipeline" means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure letdown, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

"Underground natural gas storage facility" means a subsurface facility, including, but not limited to, depleted gas or oil reservoirs and salt dome caverns, utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at a natural gas underground storage facility include, but are not limited to, compression, dehydration and flow measurement. The storage facility also includes all the wellheads connected to the compression units located at the facility.

"Valve" means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

"Vapor recovery system" means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for routing the gas back into the process as a product and/or fuel.

"Vaporization unit" means a process unit that performs controlled heat input to vaporize liquefied natural gas to supply transmission and distribution pipelines, or consumers with natural gas.

"Wellhead" means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

"Wet natural gas" means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas."

NEW SECTION

WAC 173-441-510 Oil refinery combustion sources. (1) **Definition of the source category.** Combustion units at petroleum refineries using refinery gas or a mixture of refinery gas and other fuels, not including units included in WAC 173-441-520 or 173-441-530.

(2) **GHGs to report.** You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit not included in WAC 173-441-520 or 173-441-530.

(3) **Calculating GHG emissions.** The owner or operator must use the methodologies in this section to calculate the GHG emissions from stationary fuel combustion sources.

(a) CO_2 emissions from fuel combustion. For each stationary fuel combustion unit, the owner or operator must use the four-tiered approach in this subsection, subject to the conditions, requirements, and restrictions set forth in (b) of this subsection.

(i) Tier C Calculation Methodology. Calculate the annual CO_2 mass emissions for a particular type of fuel combusted in a unit, by substituting a fuel-specific default CO_2 emission factor (from Table 510.1 of this section), a default high heating value (from Table 510.1 of this section), and the annual fuel consumption (from company records kept as provided in this rule) into the Equation

510.1 of this section.

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. 510.1)}$$

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year, from company records (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV	=	Default high heat value of the fuel, from Table 510.1 of this section (mmBtu per mass or mmBtu per volume, as applicable).
EF	=	Fuel-specific default CO_2 emission factor, from Table 510.1 of this section (kg CO_2/mmBtu).
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(ii) Tier B Calculation Methodology. Calculate the annual CO_2 mass emissions for a particular type of fuel combusted in a unit, by substituting measured high heat values, a default CO_2 emission factor (from Table 510.1 or Table 510.2 of this section), and the quantity of fuel combusted (from company records kept as provided in this rule) into the following equations:

(A) Equation 510.2 of this section applies to any type of fuel.

$$CO_2 = \sum_{p=1}^{n} 1x10^{-3} (Fuel)_p * (HHV)_p * EF \qquad \text{(Eq. 510.2)}$$

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year.
$(Fuel)_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
p	=	Measurement period (month).
$(HHV)_p$	=	High heat value of the fuel for the measurement period (mmBtu per mass or volume).

EF	=	Fuel-specific default CO_2 emission factor, from Table 510.1 or Table 510.2 of this section (kg CO_2/mmBtu).
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(B) In Equation 510.2 of this section, the value of "n" depends upon the frequency at which high heat value (HHV) measurements are required under subsection (4)(c) of this section. For example, for natural gas, which requires monthly sampling and analysis, n = 6 if the unit combusts natural gas in only six months of the year.

(iii) Tier A2 Calculation Methodology. Calculate the annual CO_2 mass emissions for a particular type of fuel combusted in a unit, by substituting measurements of fuel carbon content, molecular weight (gaseous fuels, only), and the quantity of fuel combusted into the following equations. For solid fuels, the amount of fuel combusted is obtained from company records kept as provided in this rule. For liquid and gaseous fuels, the volume of fuel combusted is measured directly, using fuel flow meters (including gas billing meters). For fuel oil, tank drop measurements may also be used.

(A) For a solid fuel, use Equation 510.3 of this section.

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_p * (CC)_p \qquad \text{(Eq. 510.3)}$$

Where:

CO_2	=	Annual CO_2 mass emissions for the specific solid fuel type (metric tons).
n	=	Number of required carbon content determinations for the year.
$(Fuel)_n$	=	Mass of the solid fuel combusted in month "n" (metric tons).
p	=	Measurement period (month).
$(CC)_n$	=	Carbon content of the solid fuel, from the fuel analysis results for month "n" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
44/12	=	Ratio of molecular weights, CO_2 to carbon.

(B) For a liquid fuel, use Equation 510.4 of this section.

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_p * (CC)_p * 0.001 \qquad \text{(Eq. 510.4)}$$

Where:

CO_2	=	Annual CO_2 mass emissions for the specific liquid fuel type (metric tons).
n	=	Number of required carbon content determinations for the year.

$(Fuel)_n$	=	Volume of the liquid fuel combusted in month "n" (gallons).
p	=	Measurement period (month).
$(CC)_n$	=	Carbon content of the liquid fuel, from the fuel analysis results for month "n" (kg C per gallon of fuel).
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(C) For a gaseous fuel, use Equation 510.5 of this section.

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_p * (CC)_p * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. 510.5)}$$

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year.
$(Fuel)_n$	=	Volume of the gaseous fuel combusted on day "n" or in month "n," as applicable (scf).
p	=	Measurement period (month or day, as applicable).
$(CC)_n$	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the day or month, as applicable (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(D) In applying Equation 510.5 of this section to natural gas combustion, the CO_2 mass emissions are calculated only for those months in which natural gas is combusted during the reporting year. For the combustion of other gaseous fuels (e.g., refinery gas or process gas), the CO_2 mass emissions are calculated only for those days on which the gaseous fuel is combusted during the reporting year. For example, if the unit combusts process gas on 250 of the 365 days in the year, then n = 250 in Equation 510.5 of this section.

(iv) Tier A1 Calculation Methodology. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(A) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in (a)(iv)(D) of this subsection. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(B) When the CO_2 concentration is measured on a wet basis, Equation 510.6 of this section is used to calculate the hourly CO_2 emission rates.

$$CO_2 = 5.18x10^{-7} * C_{CO2} * Q \qquad (Eq. 510.6)$$

Where:

CO_2	=	CO_2 mass emission rate.
C_{CO2}	=	Hourly average CO_2 concentration ($\%CO_2$).
Q	=	Hourly average stack gas volumetric flow rate (scfh).
5.18×10^{-7}	=	Conversion factor (tons/scf-$\%CO_2$).

(C) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. The owner or operator must either continuously monitor the stack gas moisture content as described in 40 CFR 75.11 (b)(2) or, for certain types of fuel, use a default moisture percentage from 40 CFR 75.11 (b)(1). For each unit operating hour, a moisture correction must be applied to Equation 510.6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \qquad (Eq. 510.7)$$

Where:

CO_2*	=	Hourly CO_2 mass emission rate, corrected for moisture (metric tons/hr).
CO_2	=	Hourly CO_2 mass emission rate from Equation 510.6 of this section, uncorrected (tons/hr).
$\%H_2O$	=	Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(D) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor to determine the hourly CO_2 concentrations, in accordance with Equation F-14a or F-14b (as applicable) in Appendix F to 40 CFR Part 75, if the effluent gas stream monitored by the CEMS consists solely of combustion products and if only fuels that are listed in Table 1 in section 3.3.5 of Appendix F to 40 CFR Part 75 are combusted in the unit. If the O_2 monitoring option is selected, the F-factors used in Equations F-14a and F-14b must be determined according to section 3.3.5 or section 3.3.6 of Appendix F to 40 CFR Part 75 as applicable. If Equation F-14b is used, the hourly moisture percentage in the stack gas must be either a measured value in accordance with 40 CFR 75.11 (b)(2), or, for certain types of fuel, a default moisture value from 40 CFR 75.11 (b)(1).

(E) Each hourly CO_2 mass emission rate from Equation 510.6 or 510.7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for thirty minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(F) The hourly CO_2 mass emissions are then summed over the entire calendar year.

(G) If both biogenic fuel and fossil fuel are combusted during the year, determine the biogenic CO_2 mass emissions separately, as described in (e) of this subsection.

(b) **Use of the four tiers.** Use of the four tiers of CO_2 emissions calculation methodologies described in (a) of this subsection is subject to the following conditions, requirements, and restrictions:

(i) The Tier C Calculation Methodology may be used for any type of fuel combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, provided that:

(A) An applicable default CO_2 emission factor and an applicable default high heat value for the fuel are specified in Table 510.1 of this section.

(B) The owner or operator does not perform, or receive from the entity supplying the fuel, the results of fuel sampling and analysis on a monthly (or more frequent) basis that includes measurements of the HHV. If the owner or operator performs such fuel sampling and analysis or receives such fuel sampling and analysis results, the Tier C Calculation Methodology must not be used, and the Tier B, Tier A2, or Tier A1 Calculation Methodology must be used instead.

(ii) The Tier C Calculation Methodology may also be used to calculate the biogenic CO_2 emissions from a unit of any size that combusts wood, wood waste, or other solid biomass-derived fuels, except when the Tier A1 Calculation Methodology is used to quantify the total CO_2 mass emissions. If the Tier A1 Calculation Methodology is used, the biogenic CO_2 emissions must be calculated according to (e) of this subsection.

(iii) The Tier B Calculation Methodology may be used for any type of fuel combusted in any unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, provided that a default CO_2 emission factor for the fuel is specified in Table 510.1 or Table 510.2 of this section.

(iv) The Tier A2 Calculation Methodology may be used for a unit of any size, combusting any type of fuel, except when the use of Tier A1 is required or elected, as provided in (b)(v) of this subsection.

(v) The Tier A1 Calculation Methodology:

(A) May be used for a unit of any size, combusting any type of fuel.

(B) Must be used for a unit if:

(I) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr.

(II) The unit combusts solid fossil fuel, either as a primary or secondary fuel.

(III) The unit has operated for more than one thousand hours in any calendar year since 2005.

(IV) The unit has installed CEMS that are required either by an applicable federal or state regulation or the unit's operating permit.

(V) The installed CEMS include a gas monitor of any kind, a stack gas volumetric flow rate monitor, or both and the monitors have been certified in accordance with the requirements of 40 CFR Part 75, 40 CFR Part 60, or an applicable permitting authority continuous monitoring program.

(VI) The installed gas and/or stack gas volumetric flow rate monitors are required, by an applicable federal or state regulation or the unit's operating permit, to undergo periodic quality assurance testing in accordance with Appendix B to 40 CFR Part 75, Appendix F to 40 CFR Part 60, or an applicable permitting authority or local authority continuous monitoring program.

(C) Must be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, if the unit:

(I) Has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(II) The unit meets the other conditions specified in (b)(v)(B)(II) and (III) of this subsection.

(III) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in (b)(v)(B)(IV) through (VI) of this subsection.

(vi) The Tier A1 Calculation Methodology, if selected or required, must be used beginning on:

(A) January 1, 2010, for a unit is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(B) January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, the owner or operator must use the Tier A2 Calculation Methodology in 2010.

(c) **Calculation of CH_4 and N_2O emissions from all fuel combustion.** Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources as follows:

(i) For units subject to the requirements of the acid rain program and for other units monitoring and reporting heat input on a year-round basis according to 40 CFR 75.10(c) and 40 CFR 75.64 use Equation 510.8 of this section.

$$CH_4 \ or \ N_2O = 1x10^{-3} * (HI)_A * EF \qquad (Eq. 510.8)$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
$(HI)_A$	=	Cumulative annual heat input from the fuel, derived from the electronic data report required under 40 CFR 75.64 (mmBtu).
EF	=	Fuel-specific default emission factor for CH_4 or N_2O, from Table 510.3 of this section (kg CH_4 or N_2O per mmBtu).
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(ii) For all other units, use the applicable equations and procedures in (c)(ii) through (iv) of this subsection to calculate the annual CH_4 and N_2O emissions.

(A) If a default high heat value for a particular fuel is specified in Table 510.1 of this section and if the HHV is not measured or provided by the entity supplying the fuel on a monthly (or more frequent) basis throughout the year, use Equation 510.9 of this section.

$$CH_4 \text{ or } N_2O = 1x10^{-3} * Fuel * HHV * EF \qquad (Eq. 510.9)$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
Fuel	=	Mass or volume of the fuel combusted, from company records (mass or volume per year).
HHV	=	Default high heat value of the fuel from Table 510.1 of this section (mmBtu per mass or volume).
EF	=	Fuel-specific default emission factor for CH_4 or N_2O, from Table 510.3 of this section (kg CH_4 or N_2O per mmBtu).
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(B) If the high heat value of a particular fuel is measured on a monthly (or more frequent) basis throughout the year, or if such data are provided by the entity supplying the fuel, use Equation 510.10 of this section.

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} 1x10^{-3} * (Fuel)_p * (HHV)_p * EF \qquad (Eq. 510.10)$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
n	=	Number of required heat content measurements for the year.
$(Fuel)_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (mass or volume per unit time).
$(HHV)_p$	=	Measured high heat value of the fuel for period "p" (mmBtu per mass or volume).
p	=	Measurement period (day or month, as applicable).
EF	=	Fuel-specific default emission factor for CH_4 or N_2O, from Table 510.3 of this section (kg CH_4 or N_2O per mmBtu).
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(iii) Multiply the result from Equations 510.8, 510.9, and 510.10 of this section (as applicable) by the global warming potential (GWP) factor to convert the CH_4 or N_2O emissions to metric tons of CO_2 equivalent.

(iv) If, for a particular type of fuel, default CH_4 and N_2O emission factors are not provided in Table 510.3 of this section, the owner or operator may, subject to the approval of ecology, develop site-specific CH_4 and N_2O emission factors, based on the results of source testing.

(d) **Calculation of CO_2 from sorbent.**

(i) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use the following equation to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS.

$$CO_2 = S * R * \left(\frac{MW_{CO2}}{MW_S}\right) \qquad (Eq. 510.11)$$

Where:

CO_2	=	CO_2 emitted from sorbent for the reporting year (metric tons).
S	=	Limestone or other sorbent used in the reporting year (metric tons).
R	=	Ratio of moles of CO_2 released upon capture of one mole of acid gas.
MW_{CO2}	=	Molecular weight of carbon dioxide (44).
MW_s	=	Molecular weight of sorbent (100, if calcium carbonate).

(ii) The total annual CO_2 mass emissions for the unit must be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) **Biogenic CO_2 emissions.** If any fuel combusted in the unit meets the definition of biomass or biomass-derived fuel in WAC 173-441-030, then the owner or operator must estimate and report the total annual biogenic CO_2 emissions, according to (e)(i), (ii), or (iii) of this subsection, as applicable.

(i) The owner or operator may use Equation 510.1 of this section to calculate the annual CO_2 mass emissions from the combustion of biogenic fuel, for a unit of any size, provided that:

(A) The Tier A1 Calculation Methodology is not required or elected.

(B) The biogenic fuel consists of wood, wood waste, or other biomass-derived solid fuels.

(ii) If CEMS are used to determine the total annual CO_2 emissions, either according to 40 CFR Part 75 or the Tier A1 Calculation Methodology of this section and if both fossil fuel and biogenic fuel are combusted in the unit during the reporting year, use the following procedure to determine the annual biogenic CO_2 mass emissions.

(A) For each operating hour, use Equation 510.12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad (Eq. 510.12)$$

Where:

V_{CO2h}	=	Hourly volume of CO_2 emitted (scf).
$(\%CO_2)_h$	=	Hourly CO_2 concentration, measured by the CO_2 concentration monitor ($\%CO_2$).
Q_h	=	Hourly stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).
t_h	=	Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).
100	=	Conversion factor from percent to a decimal fraction.

(B) Sum all of the hourly V_{CO2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(C) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation 510.13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation 510.13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{Fuel * F_c * GCV}{10^6} \qquad (Eq. 510.13)$$

Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of Appendix F to 40 CFR Part 75 or a site-specific value determined under section 3.3.6 of Appendix F to 40 CFR Part 75 (scf CO_2/mmBtu).

GCV = Gross calorific value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel).

10^6 = Conversion factor, Btu per mmBtu.

(D) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biogenic fuels.

(E) Calculate the biogenic percentage of the annual CO_2 emissions, using Equation 510.14 of this section.

$$\%Biogenic = \frac{V_{bio}}{V_{total}} * 100 \qquad (Eq. 510.14)$$

(F) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the percent biogenic obtained from Equation 510.14 of this section by the total annual CO_2 mass emissions in metric tons, as determined under (a)(iv)(D) of this subsection.

(iii) For biogas combustion, the Tier B or Tier A2 Calculation Methodology must be used to determine the annual biogenic CO_2 mass emissions, except as provided in (e)(ii) of this subsection.

(4) **Monitoring and QA/QC requirements.** The CO_2 mass emissions data for stationary combustion units must be quality-assured as follows:

(a) For units using the calculation methodologies described in this subsection, the records required under WAC 173-441-150 and 173-441-160 must include both the company records and a detailed explanation of how company records are used to estimate the following:

(i) Fuel consumption, when the Tier C and Tier B Calculation Methodologies described in subsection (3)(a) of this section are used.

(ii) Fuel consumption, when solid fuel is combusted and the Tier A2 Calculation Methodology in subsection (3)(a)(iii) of this section is used.

(iii) Fossil fuel consumption, when, pursuant to subsection (3)(e) of this section, the owner or operator of a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biogenic fuels separately reports the biogenic portion of the total annual CO_2 emissions.

(iv) Sorbent usage, if the methodology in subsection (3)(d) of this section is used to calculate CO_2 emissions from sorbent.

(b) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel usage and sorbent usage (as applicable) in (a) of this subsection, including, but not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(c) For the Tier B Calculation Methodology, the applicable fuel sampling and analysis methods incorporated by reference in WAC 173-441-700 must be used to determine the high heat values. For coal, the samples must be taken at a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed. The minimum frequency of the sampling and analysis for each type of fuel (only for the weeks or months when that fuel is combusted in the unit) is as follows:

(i) Monthly, for natural gas, biogas, fuel oil, and other liquid fuels.

(ii) For coal and other solid fuels, weekly sampling is required to obtain composite samples, which are analyzed monthly.

(d) For the Tier A2 Calculation Methodology:

(i) All oil and gas flow meters (except for gas billing meters) must be calibrated prior to the first year for which GHG emissions are reported under this part, using an applicable flow meter test method listed in WAC 173-441-700 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters must be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(ii) Oil tank drop measurements (if applicable) must be performed according to one of the methods listed in WAC 173-441-700.

(iii) The carbon content of the fuels listed in (c)(i) and (ii) of this subsection must be determined monthly. For other gaseous fuels (e.g., refinery gas, or process gas), daily sampling and analysis is required to determine the carbon content and molecular weight of the fuel. An applicable method listed in WAC 173-441-700 must be used to determine the carbon content and (if applicable) molecular weight of the fuel.

(e) For the Tier A1 Calculation Methodology, the CO_2 and flow rate monitors must be certified prior to the applicable deadline specified in subsection (3)(b)(vi) of this section.

(i) For initial certification, use the following procedures:

(A) 40 CFR 75.20 (c)(2) and (4) and Appendix A to 40 CFR Part 75.

(B) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in Appendix B to Part 60 (for the CO_2 concentration monitor) and Performance Specification 6 in Appendix B to Part 60 (for the continuous emission rate monitoring system (CERMS)).

(C) The provisions of an applicable state continuous monitoring program.

(ii) If an O_2 concentration monitor is used to determine CO_2

concentrations, the applicable provisions of 40 CFR Part 75, 40 CFR Part 60, or an applicable permitting authority or an applicable permitting authority continuous monitoring program must be followed for initial certification and ongoing quality assurance, and all required RATAs of the monitor must be done on a percent CO_2 basis.

(iii) For ongoing quality assurance, follow the applicable procedures in Appendix B to 40 CFR Part 75, Appendix F to 40 CFR Part 60, or an applicable permitting authority continuous monitoring program. If Appendix F to 40 CFR Part 60 is selected for ongoing quality assurance, perform daily calibration drift (CD) assessments for both the CO_2 and flow rate monitors, conduct cylinder gas audits of the CO_2 concentration monitor in three of the four quarters of each year (except for nonoperating quarters), and perform annual RATAs of the CO_2 concentration monitor and the CERMS.

(iv) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by Appendix B to 40 CFR Part 75 and the annual RATAs of the CERMS required by Appendix F to 40 CFR Part 60 need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) **Procedures for estimating missing data.** Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter must be used in the calculations.

(a) For all units subject to the requirements of the acid rain program, the applicable missing data substitution procedures in 40 CFR Part 75 must be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, gross calorific value (GCV), and fuel carbon content.

(b) For all units that are not subject to the requirements of the acid rain program, when the Tier C, Tier B, Tier A2, or Tier A1 calculation is used, perform missing data substitution as follows for each parameter:

(i) For each missing value of the heat content, carbon content, or molecular weight of the fuel, and for each missing value of CO_2 concentration and percent moisture, the substitute data value must be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period.

(ii) For missing records of stack gas flow rate, fuel usage, and sorbent usage, the substitute data value must be the best available estimate of the flow rate, fuel usage, or sorbent consumption, based on all available process data (e.g., steam production, electrical load, and operating hours). The owner or operator must document and keep records of the procedures used for all such estimates.

(6) **Data reporting requirements.**

(a) In addition to the facility-level information required under WAC 173-441-150 and 173-441-160, the annual GHG emissions report must contain the unit-level or process-level emissions data in (b) and (c) of this subsection (as applicable) and the emissions verification data in (d) of this subsection.

(b) Unit-level emissions data reporting. Except where aggregation of unit-level information is permitted under (c) of this subsection, the owner or operator must report:

(i) The unit ID number (if applicable).

(ii) A code representing the type of unit.

(iii) Maximum rated heat input capacity of the unit, in mmBtu/hr (boilers, combustion turbines, engines, and process heaters only).

(iv) Each type of fuel combusted in the unit during the report year.

(v) The calculated CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e.

(vi) The method used to calculate the CO_2 emissions for each type of fuel combusted (e.g., Part 75 of this chapter or the Tier C or Tier B Calculation Methodology).

(vii) If applicable, indicate which one of the monitoring and reporting methodologies in 40 CFR Part 75 was used to quantify the CO_2 emissions (e.g., CEMS, Appendix G, LME).

(viii) The calculated CO_2 emissions from sorbent (if any), expressed in metric tons.

(ix) The total GHG emissions from the unit for the reporting year, i.e., the sum of the CO_2, CH_4, and N_2O emissions for all fuel types, expressed in metric tons of CO_2e.

(c) Reporting alternatives for stationary combustion units. For stationary combustion units, the following reporting alternatives may be used to simplify the unit-level reporting required under (b) of this subsection:

(i) Aggregation of small units. If a facility contains two or more units (e.g., boilers or combustion turbines) that have a combined maximum rated heat input capacity of 250 mmBtu/hr or less, the owner or operator may report the combined emissions for the group of units in lieu of reporting separately the GHG emissions from the individual units, provided that the amount of each type of fuel combusted in the units in the group is accurately quantified. More than one such group of units may be defined at a facility, so long as the aggregate maximum rated heat input capacity of the units in the group does not exceed 250 mmBtu/hr. If this option is selected, the following information must be reported instead of the information in (b) of this subsection:

(A) Group ID number, beginning with the prefix "GP."

(B) The ID number of each unit in the group.

(C) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).

(D) Each type of fuel combusted in the units during the reporting year.

(E) The calculated CO_2, CH_4, and N_2O mass emissions for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO_2e.

(F) The methodology used to calculate the CO_2 mass emissions for each type of fuel combusted in the units.

(G) The calculated CO_2 mass emissions (if any) from sorbent.

(H) The total GHG emissions from the group for the year, i.e., the sum of the CO^2, CH_4, and N_2O emissions across, all fuel types, expressed in metric tons of CO_2e.

(ii) Monitored common stack configurations. When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack, if CEMS are used to continuously monitor CO_2 mass emissions at the common stack according to 40 CFR Part 75 or as described in the Tier A1 Calculation Methodology in subsection (3)(a)(iv) of this section, the owner or operator may report the combined emissions from the units sharing the common stack, in lieu of reporting separately the GHG emissions from the individual units. If this option is selected, the following information must be reported instead of the information in (b) of this subsection:

(A) Common stack ID number, beginning with the prefix "CS."

(B) ID numbers of the units sharing the common stack.

(C) Maximum rated heat input capacity of each unit sharing the common stack (mmBtu/hr).

(D) Each type of fuel combusted in the units during the year.

(E) The methodology used to calculate the CO_2 mass emissions (i.e., CEMS or the Tier A1 Calculation Methodology).

(F) The total CO_2 mass emissions measured at the common stack for the year, expressed in metric tons of CO_2e.

(G) The combined annual CH_4 and N_2O emissions from the units sharing the common stack, expressed in metric tons of each gas and in metric tons of CO_2e.

(I) If the monitoring is done according to 40 CFR Part 75, use Equation 510.8 of this section, where the term "$(HI)_A$" is the cumulative annual heat input measured at the common stack.

(II) For the Tier A1 Calculation Methodology, use Equations 510.9 and 510.10 of this section separately for each type of fuel combusted in the units during the year, and then sum the emissions for all fuel types.

(H) The total GHG emissions for the year from the units that share the common stack, i.e., the sum of the CO_2, CH_4, and N_2O emissions, expressed in metric tons of CO_2e.

(iii) Common pipe configurations. When two or more oil-fired or gas-fired stationary combustion units at a facility combust the same type of fuel and that fuel is fed to the individual units through a common supply line or pipe, the owner or operator may report the combined emissions from the units served by the common supply line, in lieu of reporting separately the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a calibrated fuel flow meter. If this option is selected, the following information must be reported instead of the information in (b) of this subsection:

(A) Common pipe ID number, beginning with the prefix "CP."

(B) ID numbers of the units served by the common pipe.

(C) Maximum rated heat input capacity of each unit served by the common pipe (mmBtu/hr).

(D) The type of fuel combusted in the units during the reporting year.

(E) The methodology used to calculate the CO_2 mass emissions.

(F) The total CO_2 mass emissions from the units served by the common pipe for the reporting year, expressed in metric tons of CO_2e.

(G) The combined annual CH_4 and N_2O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO_2e.

(H) The total GHG emissions for the reporting year from the units served by the common pipe, i.e., the sum of the CO_2, CH_4, and N_2O emissions, expressed in metric tons of CO_2e.

(d) Verification data. The owner or operator must retain sufficient data and supplementary information to verify the reported GHG emissions.

(i) For stationary combustion sources using the Tier C, Tier B, Tier A2, or Tier A1 Calculation Methodology in subsection (3)(a)(iv) of this section to quantify CO_2 emissions, the following additional information must be included in the GHG emissions report:

(A) For the Tier C Calculation Methodology, report the total quantity of each type of fuel combusted during the reporting year, in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(B) For the Tier B Calculation Methodology, report:

(I) The total quantity of each type of fuel combusted during each month (except for MSW). Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(II) The number of required high heat value determinations for each type of fuel for the reporting year (i.e., "n" in Equation 510.2 of this section, corresponding (as applicable) to the number of operating days or months when each type of fuel was combusted, in accordance with subsections (3)(a)(ii) and (4)(c) of this section.

(III) For each month, the high heat value used in Equation 510.2 of this section for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels.

(IV) For each reported HHV, indicate whether it is an actual measured value or a substitute data value.

(V) Each method from WAC 173-441-700 used to determine the HHV for each type of fuel combusted.

(VI) For MSW, the total quantity (i.e., lb.) of steam produced from MSW combustion during the year, and "B," the ratio of the unit's maximum rate heat input capacity to its design rated steam output capacity, in mmBtu per lb. of steam.

(C) For the Tier A2 Calculation Methodology, report:

(I) The total quantity of each type of fuel combusted during each month or day (as applicable), in metric tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(II) The number of required carbon content determinations for each type of fuel for the reporting year, corresponding (as applicable) to the number of operating days or months when each type of fuel was combusted, in accordance with subsections (3)(a)(iii) and (4)(d) of this section.

(III) For each operating month or day, the carbon content (CC) value used in Equation 510.3, 510.4, or 510.5 of this section (as applicable), expressed as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels.

(IV) For gaseous fuel combustion, the molecular weight of the fuel used in Equation 510.5 of this section, for each operating month or day, in kg per kg-mole.

(V) For each reported CC value, indicate whether it is an actual measured value or a substitute data value.

(VI) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the fuel flow meters used to measure the amount of fuel combusted.

(VII) For fuel oil combustion, each method from WAC 173-441-700 used to make tank drop measurements (if applicable).

(VIII) Each method from WAC 173-441-700 used to determine the CC for each type of fuel combusted.

(IX) Each method from WAC 173-441-700 used to calibrate the fuel flow meters (if applicable).

(D) For the Tier A1 Calculation Methodology, report:

(I) The total number of source operating days and the total number of source operating hours in the reporting year.

(II) Whether the CEMS certification and quality assurance procedures of 40 CFR Part 75 of this chapter, 40 CFR Part 60, or an applicable permitting authority continuous monitoring program have been selected.

(III) The CO_2 emissions on each operating day, i.e., the sum of the hourly values calculated from Equation 510.6 or 510.7 of this section (as applicable), in metric tons.

(IV) For CO_2 concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the number of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(V) The dates and results of the initial certification tests of the CEMS.

(VI) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(E) If CO_2 emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(I) The total amount of sorbent used during the report year, in metric tons.

(II) The molecular weight of the sorbent.

(III) The ratio ("R") in Equation 510.11 of this section.

(F) For units that combust both fossil fuel and biogenic fuel, when CEMS are used to quantify the annual CO_2 emissions, the owner or operator must report the following additional information, as applicable:

(I) The annual volume of CO_2 emitted from the combustion of all fuels, i.e., Vtotal, in scf.

(II) The annual volume of CO_2 emitted from the combustion of fossil fuels, i.e., Vff, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO_2 for each fuel separately as well as the total.

(III) The annual volume of CO_2 emitted from the combustion of biogenic fuels, i.e., V_{bio}, in scf.

(IV) The carbon-based F-factor used in Equation 510.14 of this section, for each type of fossil fuel combusted, in scf CO_2 per mmBtu.

(V) The annual average GCV value used in Equation 510.14 of this section, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(VI) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(VII) The total annual biogenic CO_2 mass emissions, in metric tons.

(ii) Within seven days of receipt of a written request (e.g., a request by electronic mail) from the administrator or from the applicable state or local air pollution control agency, the owner or operator must submit the explanations described in subsection (4)(a) and (b) of this section, as follows:

(A) A detailed explanation of how company records are used to quantify fuel consumption, if Calculation Methodology Tier C or Tier B is used to calculate CO_2 emissions.

(B) A detailed explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier A2 Calculation Methodology in subsection (3)(a)(iii) of this section is used to calculate CO_2 emissions.

(C) A detailed explanation of how sorbent usage is quantified, if the methodology in subsection (3)(d) of this section is used to calculate CO_2 emissions from sorbent.

(D) A detailed explanation of how company records are used to quantify fossil fuel consumption, when, as described in subsection (3)(e) of this section, the owner or operator of a unit that combusts both fossil fuel and biogenic fuel uses CEMS to quantify CO_2 emissions.

(7) Records that must be retained. The recordkeeping requirements of WAC 173-441-160 and, if applicable, subsection (4)(a) and (b) of this section must be fully met for affected facilities with stationary combustion sources. Also, the records required under subsection (5)(a)(i) of this section, documenting the data substitution procedures for missing stack flow rate, fuel flow rate, fuel usage and (if applicable) sorbent usage information and site-specific source testing (as allowed in subsection (3)(c)(iv) of this section), must be retained. No special recordkeeping beyond that specified in WAC 173-441-160, and

subsections (4)(a) and (b) and (5)(b)(ii) of this section are required.

Table 510.1. Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and Coke	**mmBtu/short ton**	**kg CO_2/mmBtu**
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Sub-bituminous	17.25	97.02
Lignite	14.21	96.36
Unspecified (Residential/Commercial)	22.24	95.26
Unspecified (Industrial Coking)	26.28	93.65
Unspecified (Other Industrial)	22.18	93.91
Unspecified (Electric Power)	19.97	91.38
Coke	21.80	102.04
Natural Gas	**mmBtu/scf**	**kg CO_2/mmBtu**
Unspecified (Weighted US Average)	1.027×10^{-3}	53.02
Petroleum Products	**mmBtu/gallon**	**kg CO_2/mmBtu**
Asphalt and Road Oil	0.158	75.55
Aviation Gasoline	0.120	69.14
Distillate Fuel Oil (# 1, 2, & 4)	0.139	73.10
Jet Fuel	0.135	70.83
Kerosene	0.135	72.25
LPG (energy use)	0.092	62.98
Propane	0.091	63.02
Ethane	0.069	59.54
Isobutane	0.099	65.04
n-Butane	0.103	64.93
Lubricants	0.144	74.16
Motor Gasoline	0.124	70.83
Residual Fuel Oil (# 5 & 6)	0.150	76.74
Crude Oil	0.138	74.49
Naphtha (> 401 deg. F)	0.125	66.46
Natural Gasoline	0.110	66.83
Other Oil (> 401 deg. F)	0.139	73.10
Pentanes Plus	0.110	66.83
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.04
Special Naphtha	0.125	72.77
Unfinished Oils	0.139	74.49
Waxes	0.132	72.58
Biomass-derived Fuels (solid)	**mmBtu/short ton**	**kg CO_2/mmBtu**
Wood and Wood waste (12% moisture content) or other solid biomass-derived fuels	15.38	93.80
Biomass-derived Fuels (Gas)	**mmBtu/scf**	**kg CO_2/mmBtu**
Biogas	Varies	52.07

Note: Heat content factors are based on higher heating values (HHV). Also, for petroleum products, the default heat content values have been converted from units of mmBtu per barrel to mmBtu per gallon.

Table 510.2. Default CO_2 Emission Factors for the Combustion of Alternative Fuels

Fuel Type	Default CO_2 Emission Factor (kg CO_2/mmBtu)
Waste Oil	74
Tires	65
Plastics	75
Solvents	74
Impregnated Saw Dust	75

Fuel Type	Default CO_2 Emission Factor (kg CO_2/mmBtu)
Other Fossil Based Wastes	80
Dried Sewage Sludge	110
Mixed Industrial Waste	83
Municipal Solid Waste	90.652

Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.

Table 510.3. Default CH_4 and N_2O Emission Factors for Various Types of Fuel

Fuel Type	Default CH_4 Emission Factor (kg CH_4/mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Asphalt	3.0×10^{-3}	6.0×10^{-4}
Aviation Gasoline	3.0×10^{-3}	6.0×10^{-4}
Coal	1.0×10^{-2}	1.5×10^{-3}
Crude Oil	3.0×10^{-3}	6.0×10^{-4}
Digester Gas	9.0×10^{-4}	1.0×10^{-4}
Distillate	3.0×10^{-3}	6.0×10^{-4}
Gasoline	3.0×10^{-3}	6.0×10^{-4}
Jet Fuel	3.0×10^{-3}	6.0×10^{-4}
Kerosene	3.0×10^{-3}	6.0×10^{-4}
Landfill Gas	9.0×10^{-4}	1.0×10^{-4}
LPG	1.0×10^{-3}	1.0×10^{-4}
Lubricants	3.0×10^{-3}	6.0×10^{-4}
Municipal Solid Waste	3.0×10^{-2}	4.0×10^{-3}
Naphtha	3.0×10^{-3}	6.0×10^{-4}
Natural Gas	9.0×10^{-4}	1.0×10^{-4}
Natural Gas Liquids	3.0×10^{-3}	6.0×10^{-4}
Other Biomass	3.0×10^{-2}	4.0×10^{-3}
Petroleum Coke	3.0×10^{-3}	6.0×10^{-4}
Propane	1.0×10^{-3}	1.0×10^{-4}
Refinery Gas	9.0×10^{-4}	1.0×10^{-4}
Residual Fuel Oil	3.0×10^{-3}	6.0×10^{-4}
Tites	3.0×10^{-3}	6.0×10^{-4}
Waste Oil	3.0×10^{-2}	4.0×10^{-3}
Waxes	3.0×10^{-3}	6.0×10^{-4}
Wood and Wood Waste	3.0×10^{-2}	4.0×10^{-3}

Note: Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels and 10 percent lower for gaseous fuels. Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction." In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/mmBtu.

NEW SECTION

WAC 173-441-520 Petroleum refineries. (1) **Definition of source category.**

(a) A petroleum refinery is any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(b) This source category consists of the following sources at petroleum refineries: Catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; land disposal units; sulfur recovery plants; hydrogen plants (nonmerchant plants only).

(c) Nonmerchant hydrogen plant emissions are quantified by using the methods in WAC 173-441-530.

(2) **GHGs to report.**

(a) CO_2, CH_4, and N_2O combustion emissions from stationary combustion sources and from each flare. For each stationary combustion unit, you must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements specified in WAC 173-441-510 for stationary combustion units.

(b) CO_2, CH_4, and N_2O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit.

(c) CO_2 emissions from sour gas sent off site for sulfur recovery operations. You must follow the calculation procedures from subsection (3)(f) of this section and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this section.

(d) CO_2 process emissions from each on-site sulfur recovery plant.

(e) CO_2, CH_4, and N_2O emissions from each coke calcining unit.

(f) CO_2 emissions from asphalt blowing operations controlled using a combustion device and CH_4 emissions from asphalt blowing operations not controlled by a combustion device.

(g) CH_4 fugitive emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems.

(h) CO_2, CH_4, and N_2O emissions from each process vent not specifically included in (a) through (g) of this subsection.

(i) CH_4 emissions from on-site landfills. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of WAC 173-441-540.

(j) CO_2 and CH_4 emissions from on-site industrial wastewater treatment. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of WAC 173-441-550.

(k) CO_2 and CH_4 emissions from nonmerchant hydrogen production. You must follow the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of WAC 173-441-530.

(3) **Calculating GHG emissions.**

(a) For stationary combustion sources, if you operate and maintain a CEMS that measures total CO_2 emissions according to WAC 173-441-510, you must estimate total CO_2 emissions according to the requirements in WAC 173-441-510 (3)(a)(iv).

(b) For flares, calculate GHG emissions according to the requirements in (b)(i) and (ii) of this subsection for combustion systems fired with refinery fuel gas.

(i) Calculate the CO_2 emissions according to the applicable requirements in (b)(i)(A) through (C) of this subsection.

(A) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational, to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(B) Carbon content. If you have a continuous higher heating value monitor or carbon content monitor on the flare or if you monitor these parameters at least daily, you must use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare. If you monitor carbon content, calculate the CO_2 emissions from the flare using the applicable equation in WAC 173-441-510 (3)(a). If you monitor heat content, calculate the CO_2 emissions from the flare using the applicable equation in WAC 173-441-510 (3)(a) and the default emission factor of 60 kilograms CO_2/mmBtu on a higher heating value basis.

(C) Startup, shutdown, malfunction. If you do not measure the higher heating value or carbon content of the flare gas at least daily, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of startup, shutdown, or malfunction, and calculate the CO_2 emissions as specified in (b)(i)(C)(I) through (III) of this subsection.

(I) For periods of startup, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each startup, shutdown, or malfunction event.

(II) For periods of normal operation, use the average heating value measured for the refinery fuel gas for the heating value of the flare gas.

(III) Calculate the CO_2 emissions using Equation 520.1 of this section.

$$CO_2 = Flare_n * HHV * (0.001 * EmF) + \sum_{p=1}^{n} \frac{44}{12} * (Flare_{SSM})_p * (CC)_p \qquad Eq. 520.1$$

Where:

CO_2	=	Annual CO_2 emissions for a specific fuel type (metric tons/year).
$Flare_n$	=	Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).
HHV	=	Higher heating value for refinery fuel or flare gas from company records (British thermal units per scf, Btu/scf = mmBtu/MMscf).

EmF	=	Default CO_2 emission factor of 60 kilograms CO_2/mmBtu (HHV basis).
0.001	=	Unit conversion factor (metric tons per kilogram, mt/kg).
n	=	Number of startup, shutdown, and malfunction events during the reporting year.
p	=	Startup, shutdown, and malfunction event index.
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).
$Flare_{SSM}$	=	Volume of flare gas combusted during a startup, shutdown, or malfunctions from engineering calculations, (MMscf/event).
$(CC)_p$	=	Average carbon content of the gaseous fuel, from the fuel analysis results or engineering calculations for the event (gram C per scf = metric tons C per MMscf).

(ii) Calculate CH_4 and N_2O emissions according to the requirements in WAC 173-441-510 (3)(c)(ii) using the emission factors for refinery gas in WAC 173-441-510 Table 510.3.

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in (c)(i) through (iv) of this subsection.

(i) For catalytic cracking units and fluid coking units that use a continuous CO_2 CEMS for the final exhaust stack, calculate the combined CO_2 emissions from each catalytic cracking or fluid coking unit and CO boiler (if present) using the CEMS according to the Tier A1 Calculation Methodology requirements in WAC 173-441-510 (3)(a)(iv). For units that do not have a CO boiler or other post-combustion device, Equation 520.3 of this section may be used as an alternative to a continuous flow monitor, if one is not already present.

(ii) For catalytic cracking units and fluid coking units that do not use a continuous CO_2 CEMS for the final exhaust stack, you must continuously monitor the O_2, CO, and CO_2 concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels and calculate the CO_2 emissions according to the requirements of (c)(ii)(A) of this subsection:

(A) Calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation 520.2 of this section.

$$CO_2 = \sum_{1}^{n} (Q_r)_n * \frac{(\%CO_2 + \%CO)_n}{100\%} * \frac{44}{MVC} * 0.001 \qquad \text{Eq. 520.2}$$

Where:

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

Qr	=	Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).
$\%CO_2$	=	Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis).
%CO	=	Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero.
44	=	Molecular weight of CO_2 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
0.001	=	Conversion factor (metric ton/kg).
n	=	Number of hours in calendar year.

(B) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation 520.3 of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2} \qquad Eq. 520.3$$

Where:

Qr	=	Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).
Qa	=	Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
Qoxy	=	Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).

$\%O_2$	=	Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis).
%Ooxy	=	O_2 concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume - dry basis).
$\%CO_2$	=	Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis).
%CO	=	Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume - dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero.

(C) If a CO boiler or other post-combustion device is used, calculate the GHG emissions from the fuel fired to the CO boiler or post-combustion device using the methods for stationary combustion sources in (a) of this subsection and report this separately for the combustion unit.

(iii) Calculate CH_4 emissions using Equation 520.4 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_1}{EmF_2}\right) \qquad Eq. 520.4$$

Where:

CH_4	=	Annual methane emissions from coke burn-off (metric tons CH_4/year) .
CO_2	=	Emission rate of CO_2 from coke burn-off calculated in subsection (3)(c)(i) and (ii), (e)(i) and (ii), (g)(i) or (ii) of this section, as applicable (metric tons/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke, 102.04 kg CO_2/mmBtu.
EmF_2	=	Default CH_4 emission factor for petroleum coke, 3.0×10^{-3} kg CH_4/mmBtu.

(iv) Calculate N_2O emissions using Equation 520.5 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_1}{EmF_2}\right) \qquad Eq. 520.5$$

Where:

N_2O	=	Annual nitrous oxide emissions from coke burn-off (mt N_2O/year) .
EmF_1	=	Default CO_2 emission factor for petroleum coke, 102.04 kg CO_2/mmBtu.
EmF_2	=	Default N_2O emission factor for petroleum coke, from 6.0 x 10^{-4} kg N_2O/mmBtu.

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in WAC 173-441-510 of this chapter for combustion sources. Alternatively, you may use the methods in (c) of this subsection provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO_2 emissions using either the methods described in (e)(i) or (ii) of this subsection and calculate the CH_4 and N_2O emissions using the Equations 520.4 and 520.5 of this section, respectively.

(i) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using the methods in (c)(i) or (ii) of this subsection; or

(ii) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using Equation 520.6 of this section.

$$CO_2 = \sum_{1}^{n} (CB_Q)_n * CF * \frac{44}{12} * 0.001 \qquad Eq. 520.6$$

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year) .
CB_Q	=	Coke burn-off quantity per regeneration cycle (kg coke/cycle).
CF	=	Site-specific fraction carbon content of produced coke, use 0.94 if site-specific fraction carbon content is unavailable (kg C per kg coke).
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).
n	=	Number of regeneration cycles in the calendar year.
0.001	=	Conversion factor (mt/kg).

(f) For on-site sulfur recovery plants, calculate CO_2 process emissions from sulfur recovery plants according to the requirements in (f)(i) through (iv) of this subsection. Except as provided in (f)(iv) of this subsection, combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported using WAC 173-441-510. For the purposes of this section, the sour gas stream for which monitoring is required according to (f)(i) through (iii) of this subsection is not considered a fuel.

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

(ii) Carbon content. If you have a continuous compositional or carbon content monitor on the sour gas feed to the sulfur recovery plant or if you monitor these parameters on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor or use the default factor of 0.20.

(iii) Calculate the CO_2 emissions from each sulfur recovery plant using Equation 520.7 of this section.

$$CO = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \qquad Eq. 520.7$$

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year) .
F_{SG}	=	Volumetric flow rate of sour gas feed to the sulfur recovery plant (scf/year).
44	=	Molecular weight of CO_2 (kg/kg-mole).
MVC		Molar volume conversion factor (849.5 scf/kg mole).
MF_C	=	Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.
0.001	=	Conversion factor, kg to metric tons.

(iv) As an alternative to the monitoring methods in (f)(i) through (iii) of this subsection, you may use a continuous flow monitor and CO_2 CEMS in the final exhaust stack from the sulfur recovery plant according to the requirements in WAC 173-441-510 (3)(a)(iv) to calculate the combined process and combustion emissions for the sulfur recovery plant. You must monitor fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use using WAC 173-441-510. You must report the process emissions from the sulfur recovery plant as the difference in the CO_2 CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in (g)(i) through (iii) of this subsection.

(i) For coke calcining units that use a continuous CO_2 CEMS for the final exhaust stack, calculate the combined CO_2 emissions from the coke calcining process and any auxiliary fuel combusted using the CEMS according to the requirements in WAC 173-441-510 (3)(a)(iv).

(ii) For coke calcining units that do not use a continuous CO_2 CEMS for the final exhaust stack, calculate CO_2 emissions from the coke calcining unit according to the requirements in (g)(ii)(A) and (B) of this subsection.

(A) Calculate the CO_2 emissions for any auxiliary fuel fired to the calcining unit using the applicable methods in WAC 173-441-100.

(B) Calculate the CO_2 emissions from the coke calcining process using Equation 520.8 of this section.

$$CO_2 = \frac{44}{12} * (M_{in} * CC_{GC} - (M_{out} + M_{dust}) * CC_{MPC}) \qquad Eq. 520.8$$

Where:

CO_2	=	Annual CO_2 emissions (metric tons/year) .
M_{in}	=	Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).
CC_{GC}	=	Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).
M_{out}	=	Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).
M_{dust}	=	Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year).
CC_{MPC}	=	Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).
44	=	Molecular weight of CO_2 (kg/kg-mole).
12	=	Atomic weight of C (kg/kg-mole).

(iii) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in (g)(i) or (ii) of this subsection, as applicable, and calculate CH_4 using Equation 520.4 of this section and N_2O emissions using Equation 520.5 of this section.

(h) For asphalt blowing operations, calculate GHG emissions according to the applicable provisions in (h)(i) and (ii) of this subsection.

(i) For uncontrolled asphalt blowing operations, calculate CH_4

emissions using Equation 520.9 of this section.

$$CH_4 = \left(Q_{AB} * EF_{AB} * \frac{16}{MVC} * 0.001\right) \qquad Eq. 520.9$$

Where:

CH_4	=	Annual methane emissions from uncontrolled asphalt blowing (metric tons CH_4/year) .
Q_{ab}	=	Quantity of asphalt blown (million barrels per year, MMbbl/year).
EF_{AB}	=	Emission factor for asphalt blowing from facility-specific test data (scf CH_4/MMbbl); use 2,555,000 scf CH_4/MMbbl if facility-specific test data are unavailable.
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
0.001	=	Conversion factor (metric ton/kg).

(ii) For controlled asphalt blowing operations, calculate CO_2 emissions using Equation 520.10 of this section, provided these emissions are not already included in the flare emissions calculated in (b) of this subsection.

$$CO_2 = \left(Q_{AB} * EF_{AB} * \frac{44}{MVC} * 1 * 0.001\right) \qquad Eq. 520.10$$

Where:

CO_2	=	Annual CO_2 emissions (metric ton/year).
Q_{AB}	=	Quantity of asphalt blown (MMbbl/year).
EF_{AB}	=	Default emission factor (2,555,000 scf CH_4/MMbbl).
44	=	Molecular weight of CO_2 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
1	=	Assumed conversion efficiency (kg-mole CO_2/kg-mole CH_4).
0.001	=	Conversion factor (metric tons/kg).

(i) For delayed coking units, calculate the CH_4 emissions from the depressurization of the coking unit vessel to atmosphere using the process vent method in (j) of this subsection and calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation 520.11 of this section.

$$CH_4 = \left(N * H * \frac{\pi * D^2}{4} * \frac{16}{MVC} * MF_{CH4} * 0.001\right) \qquad Eq. 520.11$$

Where:

CH_4	=	Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).
N	=	Total number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
H	=	Height of coking unit vessel (feet).
D	=	Diameter of coking unit vessel (feet).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
MF_{CH4}	=	Mole fraction of methane in coking vessel gas (kg-mole CH_4/kg-mole gas); default value is 0.03.
0.001	=	Conversion factor (metric tons/kg).

(j) For each process vent not covered in (a) through (i) of this subsection, calculate GHG emissions using the Equation 520.12 of this section. You must use Equation 520.12 of this section for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas.

$$E_x = \sum_{n=1}^{N} VR_n * MF_x * \frac{MW_x}{MVC} * VT_n * 0.001 \qquad Eq. 520.12$$

Where:

E_x	=	Annual emissions of each GHG from process vent (metric ton/yr).
N	=	Number of venting events per year.
VR_n	=	Volumetric flow rate of process vent (scf per hour per event).
44	=	Molecular weight of CO_2 (kg/kg-mole).
MF_x	=	Mole fraction of GHG x in process vent.
MW_x	=	Molecular weight of GHG x (kg/kg-mole); use 44 for CO_2 or N_2O and 16 for CH_4.
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
VT_n	=	Venting time, (hours per event).
0.001	=	Conversion factor (metric ton/kg).

(k) For uncontrolled blowdown systems, you must either use the methods for process vents in (j) of this subsection or calculate CH_4 emissions using Equation 520.13 of this section.

$$CH_4 = \left(Q_{Ref} * EF_{BD} * \frac{16}{MVC} * 0.001\right) \qquad Eq. 520.13$$

Where:

CH_4	=	Methane emission rate from blowdown systems ($mtCH_4$/year).

Q_{Ref}	=	Quantity of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility (MMbbl/year).
EF_{BD}	=	Methane emission factor for uncontrolled blown systems (scf CH_4/MMbbl); default is 137,000.
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
0.001	=	Conversion factor (metric ton/kg).

(l) For equipment leaks, calculate CH_4 emissions using the method specified in either (l)(i) or (ii) of this subsection.

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

(ii) Use Equation 520.14 of this section.

$$CH_4 = (0.4 * N_{CD} + 0.2 * N_{PU1} + 0.1 * N_{PU2} + 4.3 * N_{H2} + 6 * N_{FGS}) \qquad Eq. 520.14$$

Where:

CH_4	=	Annual methane emissions from fugitive equipment leaks (metric tons/year).
N_{CD}	=	Number of atmospheric crude oil distillation columns at the facility.
N_{PU1}	=	Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
N_{PU2}	=	Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
N_{H2}	=	Total number of hydrogen plants at the facility.
N_{FGS}	=	Total number of fuel gas systems at the facility.

(m) For storage tanks, calculate CH_4 emissions using the applicable methods in (m)(i) and (ii) of this subsection.

(i) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the TANKS Model (Version 4.09D) or estimate CH_4 emissions from storage tanks using Equation 520.15 of this section.

$$CH_4 = (0.1 * Q_{Ref}) \qquad Eq. 520.15$$

Where:

CH_4	=	Annual methane emissions from storage tanks (metric tons/year).
0.1	=	Default emission factor for storage tanks (metric ton CH_4/MMbbl).
Q_{Ref}	=	Quantity of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility (MMbbl/year).

(ii) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation 520.16 of this section.

$$CH_4 = (995{,}000 * Q_{un} * \Delta P) * MF_{CH4} * \frac{16}{MVC} * 0.001 \qquad Eq. 520.16$$

Where:

CH_4	=	Annual methane emissions from storage tanks (metric tons/year).
Q_{un}	=	Quantity of unstabilized crude oil received at the facility (MMbbl/year).
ΔP	=	Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
MF_{CH4}	=	Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default if measurement data are not available.
995,000	=	Correlation equation factor (scf gas per MMbbl per psi).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole).
0.001	=	Conversion factor (metric ton/kg).

(n) For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, report zero methane emissions.

(4) **Monitoring and QA/QC requirements.**

(a) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations must be calibrated prior to the first reporting year, using a suitable method published by a consensus standards organization (e.g., ASTM, ASME, API, AGA, etc.). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors must be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(b) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including, but not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(c) All CO_2 CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in WAC 173-441-510 (4)(e).

(5) **Procedures for estimating missing data.** A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter must be used in the calculations.

(a) For each missing value of the heat content, carbon content, or molecular weight of the fuel, the substitute data value must be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period.

(b) For missing oil and gas flow rates, use the standard missing data procedures in section 2.4.2 of Appendix D to 40 CFR Part 75.

(c) For missing CO_2, CO, or O2, CH_4, and N_2O concentrations, stack gas flow rate, and stack gas moisture content values, use the applicable initial missing data procedures in WAC 173-441-510(5).

(d) For hydrogen plants, use the missing data procedures in WAC 173-441-530.

(e) For on-site landfills, use the missing data procedures in WAC 173-441-540.

(f) For on-site industrial wastewater treatment systems, use the missing data procedures in WAC 173-441-550.

(6) **Data reporting requirements.** In addition to the reporting requirements of WAC 173-441-150, you must report the information specified in (a) through (e) of this subsection.

(a) For combustion sources, including flares, use the data reporting requirements in WAC 173-441-510(6).

(b) For hydrogen plants, use the data reporting requirements in WAC 173-441-530.

(c) Reserved.

(d) For on-site landfills, use the data reporting requirements in WAC 173-441-540.

(e) For on-site industrial wastewater treatment systems, use the data reporting requirements in WAC 173-441-550.

(f) For catalytic cracking units, traditional fluid coking units, catalytic reforming units, sulfur recovery plants, and coke calcining units, owners and operators must report:

(i) The unit ID number (if applicable).

(ii) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, catalytic reforming unit, sulfur recovery plant, or coke calcining unit).

(iii) Maximum rated throughput of the unit, in bbl/stream day, metric tons sulfur produced/stream day, or metric tons coke calcined/stream day, as applicable.

(iv) The calculated CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(v) A description of the method used to calculate the CO_2 emissions for each unit (e.g., reference section and equation number).

(g) For fluid coking unit of the flexicoking type, the owner or operator must report:

(i) The unit ID number (if applicable).

(ii) A description of the type of unit.

(iii) Maximum rated throughput of the unit, in bbl/stream day.

(iv) Indicate whether the GHG emissions from the low heat value gas are accounted for in using methods in WAC 173-441-510 or subsection (3)(c) of this section.

(v) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.

(h) For asphalt blowing operations, the owner or operator must report:

(i) The unit ID number (if applicable).

(ii) The quantity of asphalt blown.

(iii) The type of control device used to reduce methane (and other organic) emissions from the unit.

(iv) The calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.

(i) For process vents subject to subsection (3)(j) of this section, the owner or operator must report:

(i) The vent ID number (if applicable).

(ii) The unit or operation associated with the emissions.

(iii) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(iv) The calculated annual CO_2, CH_4, and N_2O emissions for each unit, expressed in metric tons of each pollutant emitted.

(j) For equipment leaks, storage tanks, uncontrolled blowdown systems, delayed coking units, and loading operations, the owner or operator must report:

(i) 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.

(ii) The method used to calculate equipment leak emissions and the calculated, cumulative CH_4 emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(iii) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for all storage tanks, except for those used to process unstabilized crude oil.

(iv) The quantity of unstabilized crude oil received during the calendar year and the cumulative CH_4 emissions (in metric tons of each pollutant emitted) for storage tanks used to process unstabilized crude oil.

(v) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for uncontrolled blowdown systems.

(vi) The total number of delayed coking units at the facility, the number of delayed coking drums per unit, the dimensions and annual number of coke-cutting cycles for each drum, and the cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for delayed coking units.

(vii) The quantity and types of materials loaded 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.

(viii) 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.

(ix) The cumulative annual CH_4 emissions (in metric tons of each pollutant emitted) for loading operations.

(k) If you have a CEMS that measures CO_2 emissions but that is not required to be used for reporting GHG emissions under this subpart (i.e., a CO_2 CEMS on a process heater stack but the combustion emissions are calculated based on the fuel gas consumption), you must identify the emission source that has the CEMS and report the CO_2 emissions as measured by the CEMS for that emissions source.

(7) **Records that must be retained.** In addition to the records required by WAC 173-441-150, you must retain the records of all parameters monitored under subsection (4) of this section, monitoring and QA/QC requirements and subsection (5) of this section, procedures for estimating missing data.

(8) **Definitions.** All terms used in this subsection have the same meaning given in WAC 173-441-030 and as follows:

"Catalytic cracking unit" means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

"Coke (petroleum)" means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

"Coke burn-off" means the coke removed from the surface of a catalyst by combustion during catalyst regeneration. Coke burn-off also means the coke combusted in fluid coking unit burner.

"Connector" means, but is not limited to, flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "Ts" or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

"Crude oil" means any of the naturally occurring liquids and semisolids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chains and rings.

"Delayed coking unit" means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors.

"Density" means the mass contained in a given unit volume (mass/volume).

"Engineering estimation" means an estimate of fugitive emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

"Flare" means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

"Flare combustion efficiency" means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip, assumed ninety-five percent for nonaspirated field flares and ninety-eight percent for steam or air aspirated flares.

"Fluid coking unit" means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The fluid coking unit includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent. There are two basic types of fluid coking units: A traditional fluid coking unit in which only a small portion of the coke produced in the unit is burned to fuel the unit and the fluid coking burner exhaust vent is directed to the atmosphere (after processing in a CO boiler or other air pollutant control equipment) and a flexicoking unit in which an auxiliary burner is used to partially combust a significant portion of the produced petroleum coke to generate a low value fuel gas that is used as fuel in other combustion sources at the refinery.

"Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for purpose of creating useful heat.

"Fuel" means solid, liquid, or gaseous combustible material.

"Fuel gas (still gas)" means gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas.

"Fuel gas system" means a system of compressors, piping, knock-out pots, mix drums, and, if necessary, units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects fuel gas from one or more sources for treatment, as necessary, and transport to a stationary combustion unit. A fuel gas system may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the various combustion units at the refinery or petrochemical plant.

"Fugitive emissions" means unintentional equipment emissions of methane and/or carbon dioxide containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. Fugitive emissions also mean CO_2 emissions resulting from combustion of natural gas in flares.

"Fugitive emissions detection" means the process of identifying emissions from equipment, components, and other point sources.

"Fugitive emissions detection instruments" means any device or instrument that has been approved for fugitive emissions detection in this rule, namely infrared fugitive emissions detection instruments, OVAs, and TVAs.

"Gaseous fuel" means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

"High heat value" or "HHV" means the high or gross heat content of the fuel with the heat of vaporization included. The water is assumed to be in a liquid state.

"Infrared remote fugitive emissions detection instrument" means an instrument that detects infrared light in the narrow wavelength range absorbed by light hydrocarbons including methane, and presents a signal (sound, digital or visual image) indicating the presence of methane and other light hydrocarbon vapor emissions in the atmosphere. For the purpose of this rule, it must detect the presence of methane.

"Lubricants" includes all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Petroleum lubricants may be produced from distillates or residues.

"Mass-balance approach" means a method for estimating emissions of fluorinated greenhouse gases from use in equipment that can be applied to aggregates of units (for example by system). In this approach, annual emissions are the difference between the quantity of gas consumed in the year and the quantity of gas used to fill the net increase in equipment capacity or to replace destroyed gas.

"Maximum rated heat input capacity" means the hourly heat input to a unit (in mmBtu/hr), when it combusts the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer.

"Mcf" means thousand cubic feet.

"Meter" means a device that measures gas flow rate from a fugitive emissions source or through a conduit by detecting a condition (pressure drop, spin induction, temperature loss, electronic signal) that varies in proportion to flow rate or measures gas velocity in a manner that can calculate flow rate.

"Miscellaneous products" includes all petroleum products not classified elsewhere. It includes petrolatum lube refining by-products (aromatic extracts and tars) absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils.

"Noncrude feedstocks" means natural gas liquids, hydrogen and other hydrocarbons, and petroleum products that are input into the atmospheric distillation column or other processing units in a refinery.

"Nonpneumatic pump" means any pump that is not pneumatically powered with pressurized gas of any type, such as natural gas, air, or nitrogen.

"Nonsteam aspirated flare" means a flare where natural gas burns at the tip with natural induction of air (and relatively lower combustion efficiency as may be evidenced by smoke formation).

"Oil-fired unit" means a stationary combustion unit that derives more than fifty percent of its annual heat input from the combustion of fuel oil, and the remainder of its annual heat input from the combustion of natural gas or other gaseous fuels.

"Oil/water separator" means equipment used to routinely handle oily water streams, including gravity separators or ponds and air flotation systems.

"Open-ended line fugitive emissions" means natural gas released from pipes or valves open on one end to the atmosphere that are intended to periodically vent or drain natural gas to the atmosphere but may also leak process gas or liquid through incomplete valve closure including valve seat obstructions or damage.

"Open-ended valve" or "lines (OELs)" means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

"Operating hours" means the duration of time in which a process or process unit is utilized; this excludes shutdown, maintenance, and standby.

"Operating pressure" means the containment pressure that characterizes the normal state of gas and/or liquid inside a particular process, pipeline, vessel or tank.

"Organic monitoring device" means an instrument used to indicate the concentration level of organic compounds exiting a control device based on a detection principle such as IR, photoionization, or thermal conductivity.

"Organic vapor analyzer (OVA)" means an organic monitoring device that uses a flame ionization detector to measure the concentrations in air of combustible organic vapors from 9 to 10,000 parts per million sucked into the probe.

"Petroleum" means oil removed from the earth and the oil derived from tar sands and shale.

"Petroleum coke" means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (ninety to ninety-five percent) and has low ash content. It is used as a feedstock in coke ovens for the steel industry, for heating purposes, for electrode manufacture and for production of chemicals.

"Pressure relief device" or "pressure relief valve" or "pressure safety valve" means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device is but not limited to a spring-loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

"Process gas" means any gas generated by an industrial process such as petroleum refining.

"Pump seals" means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

"Pump seal fugitive emissions" means natural gas released from the seal face between the pump internal chamber and the atmosphere.

"Refined petroleum product" means petroleum products produced from the processing of crude oil, lease condensate, natural gas and other hydrocarbon compounds.

"Refinery fuel gas (still gas)" means any gas generated at a petroleum refinery, or any gas generated by a refinery process unit, that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

"Residual fuel oil" means a classification for the heavier fuel oils, No. 5 and No. 6. No. 5 is also known as Navy Special and is used in steam powered vessels in government service and inshore power plants. No. 6 includes Bunker C and is used for the production of electric power, space heating, vessel bunkering and various industrial purposes.

"Rotameter" means a flow meter in which gas flow rate upward through a tapered tube lifts a "float bob" to an elevation related to the gas flow rate indicated by etched calibrations on the wall of the tapered tube.

"Semirefined petroleum product" means all oils requiring further processing. Included in this category are unfinished oils which are produced by the partial refining of crude oil and include the following: Naphthas and lighter oils; kerosene and light gas oils; Heavey gas oils; and residuum, and all products that require further processing or the addition of blendstocks.

"Sensor" means a device that measures a physical quantity/quality or the change in a physical quantity/quality, such as temperature, pressure, flow rate, pH, or liquid level.

"Shutdown" means the cessation of operation of an emission source for any purpose.

"Standard conditions" or "standard temperature and pressure (STP)" means 60°F and 14.7 pounds per square inch absolute.

"Standby" means for an equipment to be in a state ready for operation, but not operating.

"Steam aspirated flare" means steam injected into the flare burner tip to induce air mixing with the hydrocarbon fuel to promote more complete combustion as indicated by lack of smoke formation.

"Steam reforming" means a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water.

"Storage tank" means other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

"Storage tank fugitive emissions" means natural gas vented when it flashes out of liquids; this occurs when liquids are transferred from higher pressure and temperature conditions upstream, plus working losses from liquid level increases and decreases during filling and draining and standing losses (breathing losses) from diurnal temperature changes and barometric pressure changes expanding and contracting the vapor volume of a tank.

"Sulfur recovery plant" means all process units which recover sulfur or produce sulfuric acid from hydrogen sulfide (H_2S) and/or sulfur dioxide (SO_2) at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device.

"Supplemental fuel" means a fuel burned within a petrochemical process that is not produced within the process itself.

"Tanker unloading" means pumping of liquid hydrocarbon (e.g., crude oil, LNG) from an ocean-going tanker or barge to shore storage tanks.

"Toxic vapor analyzer (TVA)" means an organic monitoring device that uses a flame ionization detector and photoionization detector to measure the concentrations in air of combustible organic vapors from 9 parts per million and exceeding 10,000 parts per million sucked into the probe.

"Turbine meter" means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

"Unstabilized crude oil" means, for the purposes of this subsection, crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

"Valve" means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

"Vapor recovery system" means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for routing the gas back into the process as a product and/or fuel.

"Waste feedstocks" means noncrude feedstocks that have been contaminated, downgraded, or no longer meet the specifications of the product category or end-use for which they were intended. Waste feedstocks include, but are not limited to: Used plastics, used engine oils, used dry cleaning solvents, and trans-mix (mix of products at the interface in delivery pipelines).

NEW SECTION

WAC 173-441-530 Hydrogen production. (1) **Definition of the source category.**

(a) A hydrogen production source category produces hydrogen gas that is consumed at sites other than where it is produced.

(b) This source category comprises process units that produce hydrogen by oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes hydrogen production facilities located within a petroleum refinery and that are not owned or under the direct control of the refinery owner and operator.

(d) Hydrogen plants located within a petroleum refinery and are owned or under the direct control of the refinery owner and operator are required to use the methods in this section as directed by WAC 173-441-520.

(2) **GHGs to report.**

(a) CO_2 process emissions for each hydrogen production process unit.

(b) CO_2, CH_4, and N_2O emissions from the combustion of fuels in each hydrogen production unit and any other stationary combustion units by following the calculation procedures, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of WAC 173-441-510.

(3) **Calculating GHG emissions.** Determine CO_2 emissions in accordance with the procedures specified in either subsection (2)(a) or (b) of this section.

(a) Continuous emission monitoring system. Any hydrogen process unit that meets the conditions specified in WAC 173-441-510 (3)(b)(v)(C)(I), (II), and (III), or (3)(b)(v)(B)(I) through (VI) must calculate total CO_2 emissions using a continuous emissions monitoring system according to the Tier A1 Calculation Methodology specified in WAC 173-441-510 (3)(a)(iv).

(b) Feedstock material balance approach. If you do not measure total emissions with a CEMS, you must calculate the annual CO_2 process emissions from feedstock used for hydrogen production.

(i) Gaseous feedstock. You must calculate the total CO_2 process emissions from gaseous feedstock according to Equation 530.1 of this section.

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * (Fdstk)_n * (CC)_n * \frac{MW}{MVC}\right) * 0.001 \qquad \text{(Eq. 530.1)}$$

Where:

CO_2	=	Annual CO_2 process emissions arising from feedstock consumption (metric tons).
$(Fdstk)_n$	=	Volume of the gaseous feedstock used in month n (scf of feedstock).
$(CC)_n$	=	Average carbon content of the gaseous feedstock, from the analysis results for month n (kg C per kg of feedstock).
MW	=	Molecular weight of the gaseous feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
k	=	Months per year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(ii) Liquid feedstock. You must calculate the total CO_2

process emissions from liquid feedstock according to Equation 530.2 of this section.

$$CO_2 = (\sum_{n=1}^{k} \frac{44}{12} * (Fdstk)_n * (CC)_n) * 0.001 \qquad \text{(Eq. 530.2)}$$

Where:

CO_2	=	Annual CO_2 emissions arising from feedstock consumption (metric tons).
$(Fdstk)_n$	=	Volume of the liquid feedstock used in month n (gallons of feedstock).
$(CC)_n$	=	Average carbon content of the liquid feedstock, from the analysis results for month n (kg C per gallon of feedstock).
k	=	Months per year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(iii) Solid feedstock. You must calculate the total CO_2 process emissions from solid feedstock according to Equation 530.3 of this section.

$$CO_2 = (\sum_{n=1}^{k} \frac{44}{12} * (Fdstk)_n * (CC)_n) * 0.001 \qquad \text{(Eq. 530.3)}$$

Where:

CO_2	=	Annual CO_2 emissions arising from feedstock consumption (metric tons).
$(Fdstk)_n$	=	Mass of solid feedstock used in month n (kg of feedstock).
$(CC)_n$	=	Average carbon content of the solid feedstock, from the analysis results for month n (kg C per kg of feedstock).
k	=	Months per year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(4) **Monitoring and QA/QC requirements.**

(a) Facilities that use CEMS must comply with the monitoring and QA/QC procedures specified in WAC 173-441-510 (4)(e).

(b) The quantity of gaseous or liquid feedstock consumed must be measured continuously using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(c) You must collect a sample of each feedstock and analyze the carbon content of each sample using appropriate test methods incorporated by reference in WAC 173-441-700. The minimum frequency of the fuel sampling and analysis is monthly.

(d) All fuel flow meters, gas composition monitors, and heating value monitors must be calibrated prior to the first reporting year, using a suitable method listed in WAC 173-441-700. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors must be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(e) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(5) **Procedures for estimating missing data.** A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations, according to the following requirements:

(a) For missing feedstock supply rates, use the lesser of the maximum supply rate that the unit is capable of processing or the maximum supply rate that the meter can measure.

(b) There are no missing data procedures for carbon content. A retest must be performed if the data from any monthly measurements are determined to be invalid.

(c) For missing CEMS data, you must use the missing data procedures in WAC 173-441-510(5).

(6) **Data reporting requirements.** In addition to the information required by WAC 173-441-150, each annual report must contain the following information for each process unit:

(a) Facilities that use CEMS must comply with the procedures specified in WAC 173-441-510 (6)(c)(i)(D).

(b) Annual total consumption of feedstock for hydrogen production; annual total of hydrogen produced; and annual total of ammonia produced, if applicable.

(c) Monthly analyses of carbon content for each feedstock used in hydrogen production (kg carbon/kg of feedstock).

(7) **Records that must be retained.** In addition to the information required by WAC 173-441-160, you must retain the following records:

(a) For all CEMS, you must comply with the CEMS recordkeeping requirements in WAC 173-441-510(7).

(b) Monthly analyses of carbon content for each feedstock used in hydrogen production.

NEW SECTION

WAC 173-441-540 Landfills. (1) **Definition of source category.**

(a) This source category consists of the following sources at municipal solid waste (MSW) landfill facilities: Landfills, landfill gas collection systems, and landfill gas combustion systems (including flares). This source category also includes industrial landfills (including, but not limited to, landfills located at or owned or operated food processing, pulp and paper, and ethanol production facilities).

(b) This source category does not include hazardous waste landfills and construction and demolition landfills.

(2) **Greenhouse gases that must be reported.** Greenhouse gases that must be reported:

(a) You must report CH_4 generation and CH_4 emissions from landfills.

(b) You must report CH_4 destruction resulting from landfill gas collection and combustion systems.

(c) You must report CO_2, CH_4, and N_2O emissions from stationary fuel combustion devices. This includes emissions from the combustion of fuels used in flares (e.g., for pilot gas or to supplement the heating value of the landfill gas). CO_2 generated from flaring or other use of landfill gas is reported separately as biomass emissions and is quantified using the methods in WAC 173-441-100 (4)(a).

(3) **Calculating GHG emissions.**

(a) For all landfills subject to the reporting, calculate annual modeled CH_4 generation according to the applicable requirements in (a)(i) through (iv) of this subsection.

(i) Calculate annual modeled CH_4 generation using recorded or estimated waste disposal quantities, default values from Table 540.1 and Equation 540.1 of this section.

$$G_{CH4} = \sum_{x=S}^{T-1} \left[W_x L_{0,x} \left(e^{-k(T-x-1)} - e^{-k(T-x)} \right) \right] \qquad (Eq. 540.1$$

Where:

G_{CH4}	=	Modeled methane generation rate in reporting year T (metric tons CH_4).
X	=	Year in which waste was disposed.
S	=	Start year of calculation. Use the year 50 years prior to the year of the emissions estimate, or the opening year of the landfill, whichever is more recent.
T	=	Reporting year for which emissions are calculated.
W_x	=	Quantity of waste disposed in the landfill in year X from tipping fee receipts or other company records (metric tons, as received (wet weight)).
L_0	=	CH_4 generation potential (metric tons CH_4/metric ton waste) = MCF*DOC*DOC_F*F*16/12.
MCF	=	Methane correction factor (fraction).
DOC	=	Degradable organic carbon (fraction (metric tons C/metric ton waste)).

DOC_F	=	Fraction of DOC dissimilated (fraction).
F	=	Fraction by volume of CH_4 in landfill gas.
k	=	Rate constant (yr-1).

(ii) For years when material-specific waste quantity data are available, and for industrial waste landfills, apply Equation 540.1 of this section for each waste quantity type and sum the CH_4 generation rates for all waste types to calculate the total modeled CH_4 generation rate for the landfill. Use the appropriate parameter values for k, DOC, MCF, DOCF, and F shown in Table 540.1 of this section. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. For both MSW and industrial landfills, you may use the bulk waste parameters for a portion of your waste materials when using the material-specific modeling approach for mixed waste streams that cannot be designated to a specific material type. For years when waste composition data are not available, use the bulk waste parameter values for k and L_0 in Table 540.1 of this section for the total quantity of waste disposed in those years.

(iii) For years prior to reporting for which waste disposal quantities are not readily available for MSW landfills, W_x must be estimated using the estimated population served by the landfill in each year, the values for national average per capita waste disposal and fraction of generated waste disposed of in solid waste disposal sites found in Table 540.2 of this section.

(iv) For industrial landfills, W_x in reporting years must be determined by direct mass measurement of waste entering the landfill using industrial scales with a manufacturer's stated accuracy of ±2 percent. For previous years, where data are unavailable on waste disposal quantities, estimate the waste quantities according to the requirements in (a)(iv)(A) and (B) of this subsection.

(A) Calculate the average waste disposal rate per unit of production for the first applicable reporting year using Equation 540.2 of this section.

$$WDF = \sum_{n=1}^{N} \frac{W_n}{N * P_n} \qquad \text{(Eq. 540.2)}$$

Where:

WDF	=	Average waste disposal factor determined on the first year of reporting (metric tons per production unit). The average waste disposal factor should not be recalculated in subsequent reporting years.
N	=	Number of years for which disposal and production data are available.
W_n	=	Quantity of waste placed in the industrial landfill in year n (metric tons).

P_n	=	Quantity of product produced in year n (production units).

(B) Calculate the waste disposal quantities for historic years in which direct waste disposal measurements are not available using historical production data and Equation 540.3 of this section.

$$W_x = WDF * P_x \qquad (Eq. 540.3)$$

Where:

X	=	Historic year in which waste was disposed.
W_x	=	Projected quantity of waste placed in the landfill in year X (metric tons).
WDF	=	Average waste disposal factor from Equation 540.1 of this section (metric tons per production unit).
P_x	=	Production quantity for the facility in year X from company records (production units).

(b) For landfills with gas collection systems, calculate the quantity of CH_4 destroyed according to the requirements in (b)(i) through (ii) of this subsection.

(i) Measure continuously the flow rate, CH_4 concentration, temperature, and pressure, of the collected landfill gas (before any treatment equipment) using a monitoring meter specifically for CH_4 gas, as specified in subsection (4) of this section.

(ii) Calculate the quantity of CH_4 recovered for destruction using Equation 540.4 of this section.

$$R = \sum_{n=1}^{365}\left(V_n * \frac{C_n}{100\%} * 0.0423 * \frac{520^oR}{T_n} * \frac{P_n}{1\ atm} * 1440 * \frac{0.454}{1000}\right) \qquad (Eq. 540.4)$$

Where:

R	=	Annual quantity of recovered CH_4 (metric tons CH_4).
V_n	=	Daily average volumetric flow rate for day n (acfm).
C_n	=	Daily average CH_4 concentration of landfill gas for day n (%, wet basis). 0.0423 = Density of CH_4 lb/scf (at 520°R or 60°F and 1 atm).
T_n	=	Temperature at which flow is measured for day n (°R).
P_n	=	Pressure at which flow is measured for day n (atm)
1,440	=	Conversion factor (min/day).

0.454/1,000	=	Conversion factor (metric ton/lb).

(c) Calculate CH_4 generation (adjusted for oxidation in cover materials) and actual CH_4 emissions (taking into account any CH_4 recovery, and oxidation in cover materials) according to the applicable methods in (d)(i) through (ii) of this subsection.

(i) Calculate CH_4 generation, adjusted for oxidation, from the modeled CH_4 (G_{CH4} from Equation 540.1 of this section) using Equation 540.5 of this section.

$$MG = G_{CH4} * (1 - OX) \qquad (Eq. 540.5)$$

Where:

MG	=	Methane generation from the landfill in the reporting year, adjusted for oxidation (metric tons CH_4).
G_{CH4}	=	Modeled methane generation rate in reporting year from Equation 540.1 of this section (metric tons CH_4).
OX	=	Oxidation fraction default rate is 0.1 (10%).

(ii) For landfills that do not have landfill gas collection systems, the CH_4 emissions are equal to the CH_4 generation calculated in Equation 540.5 of this section.

(d) For landfills with landfill gas collection systems, calculate CH_4 emissions using the methodologies specified in (d)(i) and (ii) of this subsection.

(i) Calculate CH_4 emissions from the modeled CH_4 generation and measured CH_4 recovery using Equation 540.6 of this section.

$$Emissions = [(G_{CH4} - R) * (1 - OX) + R * (1 - DE)] \qquad (Eq. 540.6)$$

Where:

Emissions	=	Methane from the landfill in the reporting year (metric tons CH_4).
G_{CH4}	=	Modeled methane generation rate in reporting year from Equation 540.1 of this section or the quantity of recovered CH_4 from Equation 540.4 of this section, whichever is greater (metric tons CH_4).
R	=	Quantity of recovered CH_4 from Equation 540.4 of this section (metric tons).
OX	=	Oxidation fraction default rate is 0.1 (10%).
DE	=	Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99).

(ii) Calculate CH_4 generation and CH_4 emissions using measured CH_4 recovery and estimated gas collection efficiency and Equations

540.7 and 540.8, of this section.

$$MG = \frac{R}{CE} * (1 - OX) \qquad (Eq. 540.7)$$

$$Emissions = \left[\left(\frac{R}{CE_{CH4}} - R\right) * (1 - OX) + R * (1 - DE)\right] \qquad Eq. 540.8)$$

Where:

MG	=	Methane generation from the landfill in the reporting year (metric tons CH_4).
Emissions	=	Methane from the landfill in the reporting year (metric tons CH_4).
R	=	Quantity of recovered CH_4 from Equation 540.4 of this section (metric tons CH_4).
CE	=	Collection efficiency estimated at landfill, taking into account system coverage, operation, and cover system materials. (Default is 0.75.)
OX	=	Oxidation fraction (default rate is 0.1 (10%)).
DE	=	Destruction efficiency, (lesser of manufacturer's specified destruction efficiency and 0.99).

(4) **Monitoring and QA/QC requirements.**

(a) The quantity of waste landfilled must be determined using mass measurement equipment meeting the requirements for commercial weighing equipment as described in "Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices" NIST Handbook 44, 2008.

(b) The quantity of landfill gas CH_4 destroyed must be determined using ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference in WAC 173-441-700).

(c) All fuel flow meters and gas composition monitors must be calibrated prior to the first reporting year, using ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography; ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference in WAC 173-441-700). Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, and gas composition monitors must be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(d) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(e) The owner or operator must document the procedures used to ensure the accuracy of the estimates of disposal quantities and, if applicable, gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(5) **Procedures for estimating missing data.** A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter must be used in the calculations, according to the requirements in (a) through (c) of this subsection.

(a) For each missing value of the CH_4 content, the substitute data value must be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period.

(b) For missing gas flow rates, the substitute data value must be the arithmetic average of the quality assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period.

(c) For missing daily waste disposal data for disposal in reporting years, the substitute value must be the average daily waste disposal quantity for that day of the week as measured on the week before and week after the missing daily data.

(6) **Data reporting requirements.** In addition to the information required by WAC 173-441-150, each annual report must contain the following information for each landfill.

(a) Waste disposal for each year of landfilling.

(b) Method for estimating waste disposal.

(c) Waste composition, if available, in percentage categorized as:

(i) Municipal;

(ii) Construction and demolition;

(iii) Biosolids or biological sludges;

(iv) Industrial, inorganic;

(v) Industrial, organic;

(vi) Other, or more refined categories, such as those for which k rates are available in Table 540.1 of this section.

(d) Method for estimating waste composition.

(e) Fraction of CH_4 in landfill gas based on measured values if the landfill has a gas collection system or a default.

(f) Oxidation fraction used in the calculations.

(g) Degradable organic carbon (DOC) used in the calculations.

(h) Decay rate (k) used in the calculations.

(i) Fraction of DOC dissimilated used in the calculations.

(j) Methane correction factor used in the calculations.

(k) Annual methane generation and methane emissions (metric tons/year) according to the methodologies in subsection (3)(c)(i) and (ii) of this section. Landfills with gas collection system must separately report methane generation and emissions according to the methodologies in subsection (3) of this section and indicate which values are calculated using the methodologies in subsection (3)(c)(ii) of this section.

(l) Landfill design capacity.

(m) Estimated year of landfill closure.

(n) Total volumetric flow of landfill gas for landfills with gas collection systems.

(o) CH_4 concentration of landfill gas for landfills with gas collection systems.

(p) Monthly average temperature at which flow is measured for landfills with gas collection systems.

(q) Monthly average pressure at which flow is measured for landfills with gas collection systems.

(r) Destruction efficiency used for landfills with gas collection systems.

(s) Methane destruction for landfills with gas collection systems (total annual, metric tons/year).

(t) Estimated gas collection system efficiency for landfills with gas collection systems.

(u) Methodology for estimating gas collection system efficiency for landfills with gas collection systems.

(v) Cover system description.

(w) Number of wells in gas collection system.

(x) Acreage and quantity of waste covered by intermediate cap.

(y) Acreage and quantity of waste covered by final cap.

(z) Total CH_4 generation from landfills.

(aa) Total CH_4 emissions from landfills.

(7) **Records that must be retained.** In addition to the information required by WAC 173-441-160, you must retain the calibration records for all monitoring equipment.

Table 540.1. Emissions Factors, Oxidation Factors

Factor	Default Value	Units
Waste model--Bulk waste option		
k (precipitation < 20 inches/year)	0.02 yr	per year
k (precipitation 20-40 inches/year)	0.038 yr	per year
k (precipitation > 40 inches/year)	0.057 yr	per year
L_0 (Equivalent to DOC = 0.2028 when MCF = 1, DOC_F = 0.5, and F = 0.5)	0.067	metric tons CH_4/metric ton waste
Waste model--All MSW and industrial waste landfills		
MCF	1	

Factor	Default Value	Units
DOC_F	0.5	
F	0.5	
Waste model--MSW using waste composition option		
DOC (food waste)	0.15	Weight fraction, wet basis
DOC (garden)	0.2	Weight fraction, wet basis
DOC (paper)	0.4	Weight fraction, wet basis
DOC (wood and straw)	0.43	Weight fraction, wet basis
DOC (textiles)	0.24	Weight fraction, wet basis
DOC (diapers)	0.24	Weight fraction, wet basis
DOC (sewage sludge)	0.05	Weight fraction, wet basis
DOC (bulk waste)	0.2	Weight fraction, wet basis
k (food waste)	0.06 to 0.185[a]	per year
k (garden)	0.05 to 0.10[a]	per year
k (paper)	0.04 to 0.06[a]	per year
k (wood and straw)	0.02 to 0.03[a]	per year
k (textiles)	0.04 to 0.05[a]	per year
k (diapers)	0.05 to 0.10[a]	per year
k (sewage sludge)	.06 to 0.185[a]	per year
Waste model - Industrial waste landfills		
DOC (food processing)	0.15	Weight fraction, wet basis
DOC (pulp and paper)	0.2	Weight fraction, wet basis
k (food processing)	0.185	per year
k (pulp and paper)	0.03	per year
Calculating Methane Generation and Emissions		
OX	0.1	
DE	0.99	

[a] Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate and the greater value when it does not.

Table 540.2. Per Capita Waste Disposal Rates

Year	Waste per Capita, ton/cap/yr	% to SWDS	Year	Waste per Capita, ton/cap/yr	% to SWDS
1940	0.64	100	1974	0.71	100
1941	0.64	100	1975	0.72	100
1942	0.64	100	1976	0.73	100
1943	0.64	100	1977	0.73	100
1944	0.63	100	1978	0.74	100
1945	0.64	100	1979	0.75	100
1946	0.64	100	1980	0.75	100
1947	0.63	100	1981	0.76	100
1948	0.63	100	1982	0.77	100
1949	0.63	100	1983	0.77	100
1950	0.63	100	1984	0.78	100
1951	0.63	100	1985	0.79	100
1952	0.63	100	1986	0.79	100
1953	0.63	100	1987	0.80	100
1954	0.63	100	1988	0.80	100
1955	0.63	100	1989	0.85	84
1956	0.63	100	1990	0.84	77
1957	0.63	100	1991	0.78	76
1958	0.63	100	1992	0.76	72
1959	0.63	100	1993	0.78	71
1960	0.63	100	1994	0.77	67
1961	0.64	100	1995	0.72	63
1962	0.64	100	1996	0.71	62
1963	0.65	100	1997	0.72	61

Year	Waste per Capita, ton/cap/yr	% to SWDS	Year	Waste per Capita, ton/cap/yr	% to SWDS
1964	0.65	100	1998	0.78	61
1965	0.66	100	1999	0.78	60
1966	0.66	100	2000	0.84	61
1967	0.67	100	2001	0.95	63
1968	0.68	100	2002	1.06	66
1969	0.68	100	2003	1.06	65
1970	0.69	100	2004	1.06	64
1971	0.69	100	2005	1.06	64
1972	0.70	100	2006	1.06	64
1973	0.71	100			

NEW SECTION

WAC 173-441-550 Industrial wastewater treatment. (1) **Definition of industrial wastewater treatment system.**

(a) An industrial wastewater treatment system is the collection of all processes that treat or remove pollutants and contaminants, such as soluble organic matter, suspended solids, pathogenic organisms, and chemicals from waters released from industrial processes. This source category applies to on-site industrial wastewater treatment systems at pulp and paper mills, food processing plants, ethanol production plants, petrochemical facilities, and petroleum refining facilities.

(b) This category does not include centralized or decentralized domestic wastewater treatment plants.

(2) Greenhouse gases that must be reported. Greenhouse gases that must be reported:

(a) Annual CH_4 emissions from anaerobic industrial wastewater treatment processes.

(b) Annual CO_2 emissions for oil/water separators at petroleum refineries.

(c) CO_2, CH_4, and N_2O emissions from the combustion of fuels in stationary combustion devices and fuels used in flares; methodology described in WAC 173-441-100 (4)(a). For flares, calculate the CO_2 emissions only from pilot gas and other auxiliary fuels combusted in the flare, as specified in WAC 173-441-100. CO_2 emissions resulting from the combustion of anaerobic digester gas are to be quantified and reported as biomass emissions.

(3) **Calculating GHG emissions.**

(a) Estimate the annual CH_4 mass emissions from systems other than digesters using Equation 550.1 of this section. The value of flow and COD must be determined in accordance with the monitoring requirements described in subsection (4) of this section. The flow and COD should reflect the wastewater treated anaerobically on site in anaerobic systems such as lagoons.

$$CH_4 = \sum_{n=1}^{12} (Flow_n * COD * B_0 * MCF * 0.001) \qquad \text{Eq. 550.1}$$

Where:

CH_4	=	Annual CH_4 mass emissions from the industrial wastewater treatment system (metric tons).
$Flow_n$	=	Volumetric flow rate of wastewater sent to an anaerobic treatment system in month n (m^3/month).
COD	=	Average monthly value for chemical oxygen demand of wastewater entering anaerobic treatment systems other than digesters (kg/m^3).
B_0	=	Maximum CH_4 producing potential of wastewater (kg CH_4/kg COD), default is 0.25.
MCF	=	CH_4 conversion factor, based on relevant values in Table 550.1 of this section.
0.001	=	Conversion factor from kg to metric tons.

(b) For each petroleum refining facility having an on-site oil/water separator, estimate the annual CO_2 mass emissions using Equation 550.2 of this section using measured values for the volume of wastewater treated, and default values for emission factors by separator type from Table 550.1 of this section. The flow should reflect the wastewater treated in the oil/water separator.

$$CO_2 = \sum_{n=1}^{12} \left(EF_{sep} * V_{H2O} * C * \frac{44}{12} * 0.001\, metric\ tons\ ^{CH_4}/_{kg} \right) \qquad \text{Eq. 550.2}$$

Where:

CO_2	=	Annual emissions of CO_2 from oil/water separators (metric tons/yr).
EF_{sep}	=	Emissions factor for the type of separator (kg NMVOC/m^3 wastewater treated).
V_{H2O}	=	Volumetric flow rate of wastewater treated through oil/water separator in month m (m^3/month).
C	=	Carbon fraction in NMVOC (default = 0.6).
44/12	=	Conversion factor for carbon to carbon dioxide.
0.001	=	Conversion factor from kg to metric tons.

(c) For each anaerobic digester, estimate the annual mass of CH_4 destroyed using Equations 550.3 and 550.4 of this section.

$$CH_4d = CH_4AD * DE \qquad Eq. 550.3$$

Where:

CH_4d	=	Annual quantity of CH_4 destroyed (kg/yr).
CH_4AD	=	Annual quantity of CH_4 generated by anaerobic digester, as calculated in Equation 550.4 of this section (metric tons CH_4).
DE	=	CH_4 destruction efficiency from flaring or burning in engine (lesser of manufacturer's specified destruction efficiency and 0.99).

$$CH_4AD = \sum_{n=1}^{365}\left(V * \frac{C}{100\%} * 0.0423 * \frac{520^oR}{T_n} * \frac{P_n}{1\,atm} * 1440 * \frac{0.454}{1000}\right) \qquad \mathrm{Eq.}\,550.4$$

Where:

CH_4AD	=	Annual quantity of CH_4 generated by anaerobic digester, as calculated in Equation 550.4 of this section (metric tons CH_4).
V_n	=	Daily average volumetric flow rate for day n, as determined from daily monitoring specified in subsection (4) of this section (acfm).
C_n	=	Daily average CH_4 concentration of landfill gas for day n, as determined from daily monitoring specified in subsection (4) of this section (%, wet basis).
0.0423	=	Density of CH_4 lb/scf (at 520°R or 60°F and 1 atm).
T_n	=	Temperature at which flow is measured for day n (°R).
P_n	=	Pressure at which flow is measured for day n (atm)
1440	=	Minutes per day.
0.454/1,000	=	Conversion from pounds to metric tons.

(4) **Monitoring and QA/QC requirements.**

(a) The quantity of COD treated anaerobically must be determined using analytical methods for industrial wastewater pollutants and must be conducted in accordance with methods specified in 40 CFR Part 136.

(b) All flow meters must be calibrated using the procedures and frequencies specified by the device manufacturer.

(c) For anaerobic treatment systems, facilities must monitor the wastewater flow and COD no less than once per week. The sample location must represent the influent to anaerobic treatment for the time period that is monitored. The flow sample must correspond to the location used to measure the COD. Facilities must collect twenty-four-hour flow weighted composite samples, unless they can demonstrate that the COD concentration and wastewater flow into the anaerobic treatment system does not vary. In this case, facilities must collect twenty-four-hour time-weighted composites to characterize the changes in wastewater due to production fluctuations, or a grab sample if the influent flow is equalized resulting in little variability.

(d) For oil/water separators, facilities must monitor the flow no less than once per week. The sample location must represent the influent to oil/water separator for the time period that is monitored.

(e) The quantity of gas destroyed must be determined using any of the oil and gas flow meter test methods listed in WAC 173-441-700.

(f) All gas flow meters and gas composition monitors must be calibrated prior to the first reporting year, using a suitable method listed in WAC 173-441-700. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Gas flow meters and gas composition monitors must be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(g) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the device manufacturer.

(h) All equipment (temperature and pressure monitors and gas flow meters and gas composition monitors) must be maintained as specified by the manufacturer.

(i) If applicable, the owner or operator must document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded and the technical basis for these estimates must be provided.

(5) **Procedures for estimating missing data.** A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter must be used in the calculations, according to the following requirements in (a) and (b) of this subsection:

(a) For each missing monthly value of COD or wastewater flow treated, the substitute data value must be the arithmetic average of the quality-assured values of those parameters for the weeks immediately preceding and immediately following the missing data incident. For each missing value of the CH_4 content or gas flow rates, the substitute data value must be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident.

(b) If, for a particular parameter, no quality assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period.

(6) **Data reporting requirements.** In addition to the information required by WAC 173-441-150, each annual report must contain the following information for the industrial wastewater treatment system.

(a) Type of industrial wastewater treatment system;

(b) Percent of wastewater treated at each system component;

(c) COD;

(d) Influent flow rate;

(e) B_0;

(f) MCF;

(g) Methane emissions;

(h) Type of oil/water separator (petroleum refineries);

(i) Carbon fraction in NMVOC (petroleum refineries);

(j) CO_2 emissions (petroleum refineries);

(k) Total volumetric flow of digester gas (facilities with anaerobic digesters);

(l) CH_4 concentration of digester gas (facilities with anaerobic digesters);

(m) Temperature at which flow is measured (facilities with anaerobic digesters);

(n) Pressure at which flow is measured (facilities with anaerobic digesters);

(o) Destruction efficiency used (facilities with anaerobic digesters);

(p) Methane destruction (facilities with anaerobic digesters); and

(q) Fugitive methane (facilities with anaerobic digesters).

(7) **Records that must be retained.** In addition to the information required by WAC 173-441-160, you must retain the calibration records for all monitoring equipment.

Table 550.1. Emission Factors

Factors	Default Value	Units
B_0	0.25	Kg CH_4/kg COD
MCF - anaerobic deep lagoon, anaerobic reactor (e.g., upflow anaerobic sludge blanket, fixed film)	0.8	Fraction
MCF - anaerobic shallow lagoon (less than 2 m)	0.2	Fraction
MCF - centralized aerobic treatment system, well managed	0	Fraction
MCF - centralized aerobic treatment system, not well managed (overloaded)	0.3	Fraction
Anaerobic digester for a sludge	0.8	Fraction
C fraction in NMOC	0.6	Fraction
EF sep- Gravity Type (Uncovered)	1.11E-01	Kg NMVOC/m^3 wastewater
EF sep- Gravity Type (Covered)	3.30E-03	Kg NMVOC/m^3 wastewater
EF sep-Gravity Type--(Covered and Connected to a Destruction Device)	0	Kg NMVOC/m^3 wastewater
DAF or IAF - uncovered	4.00E-34	Kg NMVOC/m^3 wastewater
DAF or IAF - covered	1.20E-44	Kg NMVOC/m^3 wastewater
DAF or IAF - covered and connected to a destruction device	0	Kg NMVOC/m^3 wastewater

DAF = dissolved air flotation type
IAF = induced air flotation type
NMVOC = Non-Methane Volatile Organic Compounds

NEW SECTION

WAC 173-441-560 Coal pile fugitive emissions. (1) **Source category.** All owners or operators of facilities that combust coal.

(2) **Greenhouse gases to report.** Fugitive CH_4 emissions from coal storage must be reported and converted to CO_2e metric tons per year.

(3) **Calculating greenhouse gas emissions.**

(a) The operator must calculate fugitive CH_4 emissions from coal storage using Equation 560.1 of this section.

$$CH_4 = PC * EF * (CF_1 / CF_2) \qquad \text{Eq. 560.1}$$

Where:

CH_4	=	CH_4 emissions in the report year, metric tonnes per year.
PC	=	Purchased coal in the report year, tons per year.
EF	=	Default emission factor for CH_4 based on coal origin and mine type provided in Table 560.1 of this section, scf CH_4/ton.
CF_1	=	Conversion factor equals 0.04228, lbs CH_4/scf.
CF_2	=	Conversion factor equals 2,204.6, lbs/metric ton.

(b) If coal from more than one coal source or mine type is purchased in the year, the above calculation is to be done for each coal source and mine type and the resulting CH_4 emissions summed.

(4) **Monitoring and QA/QC requirements.**

(a) The owner of a combustion source that uses coal must monitor the weight of coal purchased through:

(i) Weight of coal purchased from each coal origin area and mine type during the reporting year as recorded by a scale system operated by the owner or operator of the combustion source; or

(ii) Weight of coal purchased from each coal origin area and mine type during the reporting year as recorded by a scale system operated by the supplier of the coal; or

(iii) A calculated weight for the coal purchased from each coal origin area and mine type based on the volume of the coal and an appropriate volume to weight conversion factor;

(iv) Coal origin area or coal origin areas;

(v) Coal mine type or mine types if coal from multiple mine types used.

(b) All scales or load cells used to measure quantities that are to be reported under this section must be calibrated using:

(i) Suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ASHRAE, or others); or

(ii) National Institute of Standards and Technology as listed in WAC 173-441-700; or

(iii) Calibration procedures specified by the scale, or load cell manufacturer may be used.

(c) Calibration must be performed prior to the first reporting year. After the initial calibration, recalibration must be performed at least annually or at the minimum frequency specified by the manufacturer, whichever is more frequent.

(5) **Procedures for estimating missing data.** No missing data is allowed.

(6) **Data reporting requirements.** In addition to the data required to be submitted per WAC 173-441-150, report the following:

(a) The coal origins and mine types of coal consumed, as identified in Table 560.1 of this section;

(b) The annual weight of coal purchased from each coal origin area and mine type.

(7) **Records that must be retained.** The recordkeeping requirements of WAC 173-441-160 and all records of annual tons of coal purchased by coal origin and mine type must be retained. All records of weigh scale calibration must be retained if the scale is owned or operated by the combustion source using coal.

Table 560.1. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)

Coal Origin		Coal Mine Type	
Coal Basin	States	Surface Post-Mining Factors	Underground Post-Mining Factors
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	6.5	5.1
N. Great Plains	North Dakota	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		3.6	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	5.2	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2007* April 15, 2009, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-105, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 103 of Annex 3.

NEW SECTION

WAC 173-441-700 Standard test methods accepted for use. (1) **American Society for Testing and Material.** The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(a) ASTM D240-02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.

(b) ASTM D388-05, Standard Classification of Coals by Rank.

(c) ASTM D396-08, Standard Specification for Fuel Oils.

(d) ASTM D975-08, Standard Specification for Diesel Fuel Oils.

(e) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables.

(f) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.

(g) ASTM Specification D1835-05 (2005).

(h) ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

(i) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

(j) ASTM D2013-07, Standard Practice of Preparing Coal Samples for Analysis.

(k) ASTM D2234/D2234M-07, Standard Practice for Collection of a Gross Sample of Coal.

(l) ASTM D2502-04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.

(m) ASTM D2503-92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

(n) ASTM D2880-03, Standard Specification for Gas Turbine Fuel Oils.

(o) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(p) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

(q) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.

(r) ASTM Specification D3699-07, Standard Specification for Kerosene.

(s) ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(t) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).

(u) ASTM Specification D4814-08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.

(v) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.

(w) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(x) ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.

(y) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke.

(z) ASTM D6316-04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.

(aa) ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.

(bb) ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.

(cc) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

(dd) ASTM CS-104 (1985), Carbon Steel of Medium Carbon Content.

(ee) ASTM D7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.

(ff) ASTM D6060-96 (2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.

(gg) ASTM D2502-88 (2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.

(hh) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.

(ii) UOP539-97 Refinery Gas Analysis by Gas Chromatography.

(2) **American Society of Mechanical Engineers (ASME)**. The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007-2900:

(a) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.

(b) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.

(c) ASME MFC-5M-1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.

(d) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.

(e) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.

(f) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid

Flow in Closed Conduits by Weighing Method.

(3) **American National Standards Institute (ANSI).** The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(a) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits - Method by Collection of the Liquid in a Volumetric Tank.

(b) ISO/TR 15349-1: 1998, Unalloyed steel - Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation).

(c) ISO/TR 15349-3: 1998, Unalloyed steel - Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating).

(4) **Gas Processors Association (GPA).** The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(a) GPA Standard 2172-96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.

(b) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(5) **American Gas Association.** The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(a) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).

(b) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(6) **American Petroleum Institute (API).** The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street N.W., Washington, D.C. 20005-4070:

(a) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3--Tank Gauging:

(i) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(ii) Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(iii) Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(b) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(c) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4--Proving Systems:

(i) Section 2, Displacement Provers, Third Edition, September 2003.

(ii) Section 5, Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(d) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22, Testing Protocol, Section 2, Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(7) **American Society of Heating, Refrigerating and Air Conditioning Engineers, Inc.** The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle N.E., Atlanta, Georgia 30329.

ASHRAE 41.8-1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

(8) **National Institute of Standards and Technology.**

Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices NIST Handbook 44, 2008.

NEW SECTION

WAC 173-441-800 Utility average system mix reporting. (1) **Average system mix reporting.** A utility must report its average system mix to Washington state department of commerce (commerce).

(a) **Purpose of average system mix.** The average system mix is the total of all power and market resources that the utility purchases or operates during the reporting year, prorated by the proportion of this total that is needed to serve its retail customers' load. Commerce will use this average system mix data to calculate the CO_2 utility-specific emission factor.

(b) **Example of applying the average system mix.** Example 800.1 of this section illustrates the information that utilities must report to commerce.

Example 800.1:

Utility A served 12,000 MWhs of total retail load in an annual period. Over the course of the year, Utility A received or purchased power resources totaling 16,000 MWhs from three sources: A hydro generating unit it owned (10,000 MWhs); BPA SLICE (4,000 MWhs); and market purchase contracts (2,000 MWhs).

Utility A's retail load (sales + line losses) = 12,000 MWhs

Utility A's owned or purchased power resources:

Hydro Facility Z	=	10,000 MWhs
BPA SLICE	=	4,000 MWhs
Market Purchases	=	2,000 MWhs
Total Power Resources	=	16,000 MWhs

Utility A must calculate the proportion of each electricity source's contribution to the utility's average system mix by dividing the total retail load (12,000 MWhs) by the total of all power resources (16,000 MWhs). In Example 800.1 of this section:

Divide total retail load by total power resources:	12,000/16,000	=	0.75 or 75%

Utility A must claim 75% of the power it obtained from the hydro generating unit, 75% of its BPA SLICE, as well as 75% of the market purchase contracts. (Note the two exceptions for above market power purchases in subsection (2) of this section and BPA block purchases in subsection (3) of this section).

Utility A's claims are reported as:

Hydro Facility Z:	10,000* 0.75	=	7,500 MWhs
BPA SLICE:	4,000* 0.75	=	3,000 MWhs
Market Purchases:	2,000* 0.75	=	1,500 MWhs
Total Retail Load:			12,000 MWhs

(2) **Above-market power purchases.** The utility must report as a claimed resource all of the power produced from investments in a specific above-market power resource with unique societal attributes, such as a renewable resource, for which the utility does not resell that electricity specifically as power produced by that unique power generator.

(a) **Green power program resources.** Resources sold through a utility's green power program are reported to commerce in the annual green power report and must not be included in the fuel mix average reporting. The intent of the fuel mix disclosure is to determine the fuel mix of electricity sold to general customers.

(b) **Retention of environmental attributes.** If a utility retains the environmental attributes (such as green tags or renewable energy certificates) and does not sell these attributes so that the renewable power is blended with the electricity sold to general customers, then the utility must report that renewable resource generating unit in the fuel mix disclosure reporting process.

(c) **Selling of environmental attributes.** If a utility sells the environmental attributes (such as CO_2 credits, renewable energy certificates, or the green tags from any renewable resource) but keeps the electricity, then that electricity is no longer considered a renewable resource for fuel mix purposes. For this process, that electricity must be reported as a market purchase contract and will be assigned the fuel mix of the Northwest Power Pool's net system mix.

(d) **Purchasing green tags.** If a utility purchases green tags from a specific renewable resource generating unit, then the utility must report a resource claim on that renewable generating resource. The company that sold that green tag to the utility would now report its electricity as a market purchase contract.

(e) **Example of how to address above-market purchases:** Example 800.2 of this section illustrates how to address above-market purchases.

Example 800.2:

Utility B's retail load (sales+ line losses) = 12,000 MWhs

Utility B's owned or purchased power resources:

Wind Facility Y	=	1,000 MWhs
Hydro Facility Z	=	10,000 MWhs
BPA SLICE	=	4,000 MWhs
Market Purchases	=	2,000 MWhs
Total Power Resources	=	17,000 MWhs
Total Power Resources Excluding Wind	=	16,000 MWhs

New Retail Load:

Subtract wind purchases from retail load:	12,000 - 1,000	=	11,000 MWhs
Divide new retail load by total power resources excluding wind:	11,000/16,000	=	0.6875 or 68.75%

Utility B's claims are reported as:

Hydro Facility Z:	10,000* 0.6875	=	6,875
BPA SLICE:	4,000* 0.6875	=	2,750
Market Purchases:	2,000* 0.6875	=	1,375
Wind Facility Y:			1,000 MWhs
Total Retail Load:			12,000 MWhs

(3) **BPA Block purchases.** BPA Block purchases (i.e., non-BPA SLICE purchases of power made by utilities who are not BPA full requirements customers) must be counted as part of the utility's average system mix.

(a) **Purpose of BPA Block purchases.** BPA Block is intended to be utilized strictly to serve retail load and not resold. Therefore, the full amount of BPA Block purchases made during the calendar year must be counted as part of the utility's average system mix. BPA Block purchases must be deducted from total power resource purchases and from retail load before calculating the multiplier used to apportion other resources for inclusion in the average system mix.

(b) **Example of how to address BPA Block purchases.** Example 800.3 of this section illustrates how to address BPA Block purchases.

Example 800.3:

Utility C's retail load (sales + line losses)	=	12,000 MWhs

Utility C's owned and purchased power resources:

Owned Hydro Facility	=	8,000 MWhs
Market Purchases	=	2,000 MWhs
BPA Block Purchase	=	4,000 MWhs

Total Power Resources		=	14,000 MWhs
Total Power Resources excluding BPA Block Purchases		=	10,000 MWhs

New Retail Load:

Subtract BPA Block purchases from retail load:	12,000 - 4,000	=	8,000 MWhs
Divide new retail load by total power resources excluding BPA Block purchases:	8,000/10,000	=	0.80 or 80%

Utility C's claims are reported as:

Owned Hydro Facility:	8,000* 0.80	=	6,400 MWhs
Market Purchases:	2,000* 0.80	=	1,600 MWhs
BPA Block purchase:			4,000 MWhs
Total Retail Load:			12,000 MWhs

(4) **Definitions.** All terms used in this section have the meaning given in WAC 173-441-030 and the Washington Clean Air Act unless defined below.

"BPA SLICE" means utilities that have a contracted agreement with BPA to receive at all times a portion of BPA managed resource mix.