

Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions

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Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions

**Ministry of the Environment and
Climate Change**

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1. Introduction

Where the Regulation requires the use of standard quantification methods to quantify greenhouse gas emissions from an activity those standard quantification methods are set out in the chart in Section 4 of this Guideline.

The Regulation also provides for the use of best alternative quantification methods for reports submitted in certain years. Section 3 of the Guideline sets out these best alternative quantification methods.

Section 5 of the Guideline lists the technical reference documents referred to within the standard quantification methods.

2. Definitions

For the purposes of this Guideline:

“**Act**” means the *Climate Change Mitigation and Low-Carbon Economy Act 2016*.

“**Associated gas**” has the same meaning as in the Regulation.

“**Barrel**” (“**bbf**”) means a volume equal to 42 U.S. gallons.

“**Beer**” means any beverage containing alcohol in excess of 0.1% obtained by the fermentation of an infusion or decoction of barley, malt and hops or of any similar products in drinkable water.

“**Biogenic emissions**” means the emissions from the combustion of biomass.

“**BOF steel**” means steel produced from a basic oxygen furnace.

“**Bottoming cycle plant**” means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

“**Cal-85**” means a high calcium byproduct generated during the production of quicklime or lime.

“**Calcined byproduct/waste type**” means Cal-85, lime kiln dust, waste lime and other partially calcined materials and co-products generated during the production of quicklime or lime.

“**CAN-CWB**” means direct Canadian Complexity Weight Barrel (CAN-CWB) excluding hydrogen production and cogeneration.

“**Cap and trade regulation**” means O.Reg.144/16 made under the Act.

“**Capped facility**” means a facility that is owned or operated by a capped participant and:

- a) For which a person is required to prepare an emissions report and have the report verified in accordance with the Regulation; and
- b) Which does not meet the criteria set out in paragraphs 1 to 5 of section 21 of the Cap and Trade regulation.

“Capped participant” has the same meaning as in the cap and trade regulation.

“Carbon black” means carbon pellets, powders or other products produced by the pyrolysis of hydrocarbon feedstock.

“CAS number” means the Chemical Abstracts Service Registry number.

“Catalytic cracking” means the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules through the use of a catalyst.

“Catalytic reforming” means the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

“Cement kiln dust” (“CKD”) means the fine-grained, solid, highly alkaline waste consisting of partly calcined kiln feed material, dust from cement kilns and bypass systems, including bottom ash and bypass dust removed from cement kiln exhaust gas by air pollution control devices,.

“Clinker” means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

“coated recycled boxboard” means clay coated boxboard made from recovered or recycled waste paper at the facility;

“Coal tar feedstock processed” means the coal tar feedstock that is blended and distilled to obtain distillation fractions to produce coal tar products such as oils, pitch, or oil/pitch blends, expressed in tonnes.

“Cogeneration unit” means a stationary fuel combustion device which simultaneously generates multiple forms of useful energy (usually electrical and thermal) that is (i) used by the person where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

“Cogeneration system” means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

“Coke” means coke produced by a coke oven at an iron and steel facility.

“Coke burn-off” means the removal of coke from the surface of a catalyst through combustion during catalyst regeneration.

“Combustion emissions” means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

“Consensus Based Standards Organization” means ASTM International, the American Gas Association (AGA), the American Petroleum Institute (API), the CSA Group, the Gas Processors Association (GPA), the Canadian General Standards Board, the Gas Processors Suppliers Association (GPSA), the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB), International Organization for Standardization (ISO), Environment Canada, United State Environmental Protection Agency, British Standard Institution, or Measurement Canada.

“Continuous emissions monitoring system (CEMS)” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

“Director” means a Director appointed by the Minister for the Regulation.

“Distillate fuel oil” means fuels oils No. 1, 2 and 4, light fuel oil and diesel fuel.

“Dolomite used” means dolomite added to a blast furnace at a facility.

“Dolomitic quicklime or lime”, means a lime product containing 50 to 65 per cent calcium oxide and 35 to 46 per cent magnesium oxide and is derived from dolomitic limestone. .

“Double burnt lime” means a specially sintered or double-burned form of dolomitic quicklime fines and pelletized fine that are further stabilized by the addition of iron.

“dSm³” means dry standard cubic metre – the amount of gas that would occupy a volume of one cubic metre if free of combined water at standard conditions.

“EAF steel” means steel produced from the electric arc furnace.

“Emergency generator” means a stationary combustion device, such as a reciprocating internal combustion engine or turbine:

- a) That serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the person of a facility.
- b) That operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of

emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer.

- c) And does not include a stationary combustion device that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance.

“Emergency equipment” has the same meaning as in the Regulation.

“Emission factors” (“EF”) means the rate at which a pollutant is released into the atmosphere (or captured) as a result of some process activity or unit throughput.

“Engineering estimates” means estimating emissions from engineering principles and judgment, using knowledge of the chemical and physical processes involved, the design features of the activity, and an understanding of the applicable physical and chemical laws.

“Equipment leak” means fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.

“Ethylene” means the ethylene produced from the processing of natural gas liquids or feedstock from the refining of crude oil and its derivatives.

“Facility with no access to natural gas” means a facility that is located in a geographic area, whether in a municipality or an unorganized territory, that is not covered by a certificate of public convenience and necessity for the supply of natural gas;

“Flexigas” means a low heat content gaseous fuel produced through the gasification of coke.

“Fluid catalytic cracking unit” (“FCCU”) means a process unit in a refinery in which crude oil or a crude oil-derived feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. FCCUs includes, but are not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

“Fluid coking” means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

“Fuel analytical data” means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

“Fuel ethanol” means ethyl alcohol used as automotive fuel that is biomass derived from a grain, starch or cellulosic material feedstock and denatured in accordance with Canadian Excise Tax Act or, where it originates in the United States denatured in accordance with the criteria specified in ASTM D4806.

“Fuel gas system” means a system of compressors, piping, knock-out pots, mix drums, sulphur removal units and flaring units that collects fuel gas from one or more sources for treatment, and transports it to a stationary combustion unit.

“Glass bottles and jars” means bottles and jars produced through the glass production activity.

“GJ” means gigajoules or billion joules.

“Guideline” means the “Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions” as incorporated into the Regulation.

“Gypsum panels” means panels made of gypsum plaster pressed between sheets of paper or fibreglass mat.

“High calcium hydrated lime”, means a lime product produced by combining quicklime with a sufficient quantity of water.

“High calcium quicklime or lime”, means a lime product containing 75 to 98 per cent calcium oxide and 0 to 5 per cent magnesium oxide.

“High heat value” (“HHV”) means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel.

“Hot rolled steel” means hot rolled steel produced from the reheat furnace at the facility.

“Hydrogen plant” means a plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

“Indirect useful thermal energy” has the same meaning as in the Regulation.

“LDC Tissue Products” means tissues produced at the facility by a light dry crepe (LDC) machine, where the tissue is removed from a Yankee dryer by creping action and drying is primarily accomplished by mechanical dewatering with additional convection drying;

“Mineral Wool” means fibers produced from basalt rock and slag melted in a cupola at the facility.

“Industrial ethanol” means all distilled ethyl alcohol (C₂H₅OH) other than fuel ethanol, produced and distributed in the form of pure ethyl alcohol, beverage grade alcohol, completely denatured alcohol, specially denatured alcohol and proprietary solvent blends.

“Iron coated dolime” is less than one centimeter dolomitic lime impregnated with a hard layer of iron oxide as a flux in steel making.

“Kiln” means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of clinker, lime and other products, and which includes any associated preheater or precalciner devices.

“Lime kiln dust” (“LKD”) means lime dust generated during the production of quicklime or lime.

“Lime type” means the following types of quicklime or lime derived from limestone containing varying percentages of magnesium carbonate:

- a) Dolomitic quicklime or lime;
- b) Double burnt lime;
- c) High calcium hydrated lime;
- d) High calcium quicklime or lime; and,
- e) Iron coated dolime.

“Limestone used” means limestone added to the blast furnace.

“Liquefied petroleum gas” (LPG) means a group of gaseous hydrocarbons derived from crude oil refining or natural gas fractionation, and includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene.

“Liquid iron” means liquid iron produced by a blast furnace.

“Load shedding” means the process engaged in by power system operators whereby the power load of pre-selected customers is deliberately removed from a power system in response to an abnormal condition in order to maintain the integrity of the system and minimize customer outages.

“Low heat content gas” means gases recovered from casing vents, vapor recovery systems, storage tanks and other components within the production process of crude oil, natural gas and petroleum products.

“Low Heat Value” (“LHV”) means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.

“Mass balance” means the application of the law of conservation of mass to a facility, process or piece of equipment to determine emissions based on

the difference in the input and output of a unit operation, where the accumulation and depletion of a substance are included in the calculations.

“Magnesium alloy” means melted magnesium alloy produced.

“Measurement uncertainty” means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies.

“MJ” means mega joules or one million joules.

“Nameplate generating capacity” means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

“Net power generated” means the gross electricity generation minus station service or unit service electricity requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value includes:

- a) internal consumption of electricity for the purposes of a production process, and
- b) power transmitted to the grid.

“Nitric acid” means nitric acid produced by the nitric acid production activity set out in Schedule 2 of the Regulation.

“Non-calcined calcium oxide” means calcium oxide that remains in the clinker or CKD in the form of CaCO_3 and calcium oxide in the clinker or CKD that entered the kiln as a non-carbonate species.

“Non-calcined magnesium oxide” means magnesium oxide that remains in the clinker or CKD in the form of MgCO_3 and magnesium oxide in the clinker or CKD that entered the kiln as a non-carbonate species.

“Peak shaving” means using on-site generation during periods of maximum electricity consumption expressly with the intention of lowering the energy demand component of a given billing period.

“Petroleum Coke” means a solid residue consisting mainly of carbon which is derived either from the cracking of petroleum hydrocarbons in a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulphur bituminous coal (coal coke).

“Pipeline quality natural gas” means natural gas having a high heat value equal to or greater than 36.3 MJ/m³ or less than 40.98 MJ/m³, and which is at least ninety per cent methane by volume, and which is less than five per cent carbon dioxide by volume.

“Polyethylene” means polyethylene made from polymerization of ethylene at the facility, including all saleable prime and off-grade polyethylene but excluding scrap ethylene.

“Previous Reporting Regulation” means Ontario Regulation 452/09 (Greenhouse Gas Emissions Reporting) made under the Environmental Protection Act

“Prime mover” means equipment such as an engine or water wheel that drives an electric generator and includes, but is not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

“Process emissions” means the GHG emissions from industrial processes other than fuel combustion.

“Process gas” has the same meaning as in the Regulation.

“Process vent” means an opening where a gas stream is continuously or periodically discharged during normal operation.

“Production parameter” means all information listed under that heading in the standard quantification methods.

“Pulp” means market pulp produced from chemical recovery, semi-chemical recovery or thermal mechanical processes,

“Paper” means paper products including newsprint, paperboard products and converted paper products.

“Purge gas” means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or used to provide sufficient exit velocity to prevent regressive flame travel back into the flare header.

“Quicklime” means a substance that consists of oxides of calcium and magnesium resulting from the calcination of limestone or other highly calcareous materials such as aragonite, chalk, coral, marble and shell.

“Raw sugar” means sugar whose content of sucrose by weight, in the dry state, corresponds to a polarimeter reading of less than 99.5°.

“Refinery fuel gas” has the same meaning as in the Regulation.

“Rm³” or **“reference cubic metre”** means the amount of gas that would occupy a volume of one cubic metre under reference temperature and pressure conditions.

“Regulation” means O.Reg. 143/16 made under the Act.

“Sinter machine” means equipment that is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

“Sinter production” means a process that uses a sinter machine to produce a fused aggregate of fine iron-bearing materials suited for use in a blast furnace.

“Standard conditions” means either a temperature of 15 degrees Celsius and a pressure of 101.325 kPa unless otherwise stated in the standard quantification methods or an applicable Technical Reference Document.

“Standard Temperature and Pressure” or **“STP”** has the same meaning as standard conditions.

“Standard cubic meter” or **“Sm³”** means the amount of gas that would occupy a volume of one cubic metre under standard conditions.

“Steam reforming” means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.

“Styrene” means styrene produced using a two-step catalytic process which involves the alkylation of benzene with ethylene to produce ethylbenzene followed by dehydrogenation of the ethylbenzene to produce styrene.

“Sulphur recovery unit” (**“SRU”**) means a process unit that recovers elemental sulphur from gases that contain reduced sulphur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulphur dioxide and hydrogen sulfide.

“Supplemental firing” means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant.

“TAD Tissue Products” means tissues produced at a facility by a through air dried (TAD) machine, where the tissues are molded with the use of a TAD fabric and where drying is accomplished through convection drying with minimal mechanical dewatering;

“Thermal energy sold” means useful thermal energy output from the district energy system at the facilities with the following identification numbers referred to in paragraph 3 of s.23(2) of the Regulation: 1039 and 1040;

“Topping cycle plant” means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and some of the reject heat from the electricity production process is then used to provide useful thermal output.

“Unstabilized crude oil” means crude oil that has a true vapour pressure of 5 pounds per square inch absolute (psia) or greater and 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.

“**Used oil feed**” means the used oil that is processed in the refinery process units at the facility to produce a base oil that is supplied for blending with other lubricants to create lubricant products that meet lubricant industry standards.

“**Uncapped facility**” means a facility that is not a capped facility.

“**Useful thermal output**” means the thermal energy made available in a cogeneration system for use in applications other than electrical generation.

“**Waste derived fuel**” has the same meaning as in Regulation 347 of the Revised Regulations of Ontario (General – Waste Management).

“**Waste lime**” means a byproduct produced by the kiln during the production of quicklime or lime that is not a lime type, Cal-85 or LKD.

“**Wastewater separator**” means equipment used to separate oils and water from locations downstream of process drains.

3. Best Alternative Quantification Methods

Where the Regulation provides for the use of a best alternative quantification method, the person required to report pursuant to the Regulation shall use one of the following methods as amended from time to time.

Best Alternative Quantification Method
1. U.S. EPA, 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Subparts A to Subpart PP
2. 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 3 -Industrial Processes and Product Use
3. Environment Canada, Sector Specific Protocols and Guidance Manuals, posted on the Environment Canada website
4. CO ₂ Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision— National Lime Association
5. Methodology Manual – Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI), by Clearstone Engineering.
6. American Petroleum Institute (API) Compendium of GHG Emission Methodology for the Oil and Gas Industry, August 2009

Best Alternative Quantification Method
7. CO ₂ Accounting and Reporting Standard for the Cement Industry, June 2005, Version 2.0, World Business Council for Sustainable Development
8. Calculation tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills – Version 1.1, ICFPA/NCASI

4. Standard Quantification Methods

Where the Regulation requires the use of a standard quantification method, the methods listed in the following table shall be used. Emissions from mobile equipment operation are not required to be reported pursuant to the Regulation and the method contained in the table for that activity is included for reference purposes only.

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Adipic acid production	ON.50 - ON.55	1
Ammonia production	ON.80 – ON.85	2
Carbonate use	ON.180 –ON.185	3
Cement production	ON.90 – ON.95	4
Coal storage	ON.100 – ON.105	5
Copper and nickel production	ON.260 – ON.265	6
Electricity generation	ON.40 – ON.45	7
Electricity importation	ON.60 – ON.67	8
Ferroalloy production	ON.270 – ON.275	9
General stationary combustion	ON.20 – ON.26	10
Glass production	ON.140 – ON.145	11
HCFC-22 production and HFC-23 destruction	ON.120 – ON.125	12
Hydrogen production	ON.130 – ON.135	13

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Indirect Useful Thermal Energy	ON.190 - ON.195	14
Iron and Steel production	ON.150 – ON.155	15
Lead production	ON.160 – ON.165	16
Lime production	ON.170 – ON.175	17
Magnesium production	ON.290 – ON.295	18
Mobile equipment operation (for reference purposes only)	ON.280 – ON.285	19
Natural gas distribution	ON.400 – ON.406	20
Nitric acid production	ON.310 – ON.315	21
Operation of equipment for a transmission system or a distribution system (electricity)	ON.230 – ON.235	22
Operation of equipment related to natural gas	ON.350 – ON.357	23
Petrochemical production	ON.300 - ON.305	24
Petroleum product supply	ON.390 – ON.395	25
Petroleum refining	ON.200 – ON.205	26
Phosphoric acid production	ON.340 – ON.345	27
Primary aluminum production	ON.70 – ON.75	28
Pulp and paper production	ON.210 – ON.215	29
Refinery fuel gas use within a petroleum refinery	ON.30 – ON.35	30
Soda ash production	ON.220 – ON.225	31
Zinc production	ON.240 – ON.245	32

5. Technical Reference Documents

All of the methods listed in the “Reference Title” column of the following table are incorporated into the Guideline as amended from time to time and

where the Guideline requires the use of one of these methods, the most current version shall be used.

Where the analysis or other measurements specified by the methods in the “Reference Title” column or in any of the methods in the Appendices are not offered by any supplier in Ontario, the person

- a) Shall use the most appropriate method published by a consensus-based standards organization; or
- b) Where no appropriate method is published by a consensus-based standards organization, the person shall use an industry standard method, noting where such methods are used and what methods are used.

Reference Title
Analytical Methods section of the National Lime Association ‘CO ₂ Emissions Calculation Protocol for the Lime Industry English Units Version’
ASM CS-104 UNS No. G10460 “Carbon Steel of Medium Carbon Content”.
ASME Performance Test Codes
ASTM C25 - Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime
ASTM D70 - Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)
ASTM C114 - Standard Test Methods for Chemical Analysis of Hydraulic Cement
ASTM D240 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimetre
ASTM D1298 - Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1826 - Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimetre
ASTM D1945 - Standard Test Method for Analysis of Natural Gas by Gas Chromatography
ASTM D1946 - Standard Practice for Analysis of Reformed Gas by Gas Chromatography
ASTM D2013 - Standard Practice of Preparing Coal Samples for Analysis.

Reference Title
ASTM D2163 - Standard Test Method for Determination of Hydrocarbons in Liquefied Petroleum (LP) Gases and Propane/Propene Mixtures by Gas Chromatography
ASTM D2234/D2234M - Standard Practice for Collection of a Gross Sample of Coal
ASTM D2502 - Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements
ASTM D2503 - Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements
ASTM D2597 - Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.
ASTM D3176 - Standard Practice for Ultimate Analysis of Coal and Coke.
ASTM D3238 - Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method
ASTM D3588 - Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels
ASTM D3682 - Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes.
ASTM D4057 - Standard Practice for Manual Sampling of Petroleum and Petroleum Products
ASTM D4177 - Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.
ASTM D4806 - Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel.
ASTM D4809 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM D4891 - Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion
ASTM D5142 - Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and Coke by Instrumental Procedures, for petroleum liquid based fuels and liquid waste-derived fuels
ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants

Reference Title
ASTM D5373 - Standard Test Methods for Determination of Carbon, Hydrogen and Nitrogen in Analysis Samples of Coal and Carbon in Analysis Samples of Coal and Coke
ASTM D5468 - Standard Test Method for Gross Calorific and Ash Value of Waste Materials
ASTM D5580 - Standard Test Method for Determination of Benzene, Toluene, Ethylbenzene, p/m-Xylene, o-Xylene, C9 and Heavier Aromatics, and Total Aromatics in Finished Gasoline by Gas Chromatography
ASTM D5865 - Standard Test Method for Gross Calorific Value of Coal and Coke
ASTM D6348 - Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy
ASTM D6609 - Standard Guide for Part-Stream Sampling of Coal.
ASTM D6866 - Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis
ASTM D6883 - Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles
ASTM D7430 - Standard Practice for Mechanical Sampling of Coal
ASTM D7459 - Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources
ASTM D7633 - Standard Test Method for Carbon Black Carbon Content
ASTM D7662 - Standard Test Method for Carbon Content in Carbon Black Feedstock Oils
ASTM E415 - Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry
ASTM E1019 - Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques
ASTM E1915 - Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials for Carbon, Sulfur, and Acid-Base Characteristics
ASTM E1941 - Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys by Combustion Analysis

Reference Title
ASTM UOP539 - Refinery Gas Analysis by Gas Chromatography
CCME EPC-73E: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993)
Environment Canada, "Protocols and Performance specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7 ("EPS 1/PG/7")
Gas Processors Association (GPA) 2261-00, Revised 2000 - Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.
Gas Processors Association (GPA) 2172:1996, Calculation of Gross Heating Value, Relative Density and Compressibility For Natural Gas Mixtures From Compositional Analysis
ISO 13909 - All Parts: Hard coal and coke -- Mechanical sampling
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)
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)
ISO 3170: Petroleum Liquids— Manual sampling.
ISO 3171: Petroleum Liquids— Automatic pipeline sampling.
Ontario Ministry of Energy, "Default Emissions Factors for Ontario's Cap and Trade Program".
Technical Association of the Pulp and Paper Industry (TAPPI) T684 "Gross High Heating Value of Black Liquor"
Technical Association of the Pulp and Paper Industry (TAPPI) T650 "Solids Content of Black Liquor"
Solomon Associates, "The CAN-CWB Methodology for: Regulatory Support: Public Report", January 2014.
U.S. EPA Method 320 (40 CFR part 63, Appendix A)
U.S. EPA TANKS Version 4.09D, U.S. Environmental Protection Agency, October 2005
U.S. EPA AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources

6. Applicability and Transition

A person required by the Regulation to use a standard quantification method to quantify GHG emissions for an activity engaged in 2017 or later shall use this version of the Guideline.

If a person is required to submit a revised report because of a requirement in the Regulation or the Previous Reporting Regulation, the person shall, for each activity required to be addressed in the revised report, use the standard quantification method contained in the version of this Guideline or the Guideline for Greenhouse Gas Emissions Reporting as incorporated into the Previous Reporting Regulation that was in effect for the year that was the subject of the original report.

Appendices

ON.50 Adipic Acid Production

ON.51 Activity Definition

For the purposes of this standard quantification method:

“Adipic acid production” has the same meaning as in the Regulation.

“Person” means a person that engages in adipic acid production.

ON.52 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.50 – ON.55, in an emission report prepared for a calendar year in respect of adipic acid production at a facility:

(a) Annual process N₂O emissions from adipic acid production (tonnes).

Production Parameter

(b) Annual adipic acid production (tonnes).

ON.53 Calculation of N₂O Emissions

(a) The person shall determine annual N₂O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section:

(1) Using a site-specific emission factor and production data according to paragraphs (b) through (g) of this section.

(2) Using a continuous emissions monitoring system (CEMS).

(b) The person shall conduct an annual performance test or use continuous monitors according to paragraphs (b)(1) through (b)(3) of this section.

(1) The person shall either conduct the test on the waste gas stream from the nitric acid oxidation step of the process using the methods specified in ON.54 (b) through (d) or use a continuous monitoring system.

(2) The person shall either conduct the performance test under normal process operating conditions and without using N₂O abatement technology or use a continuous monitoring system.

(3) The person shall measure the adipic acid production during the test and calculate the production rate for the test period; or measure the adipic acid production during the continuous monitoring period in tonnes per hour.

(c) The person shall determine an N₂O emissions factor to use in Equation 50-2 of this section according to paragraphs (c)(1) or (c)(2) of this section.

(1) The person may use CEMS to determine N₂O concentration according to the procedures in paragraphs (a)(2) of this section.

(2) Using the results of the test or continuous process monitors in paragraph (b) of this section, the person shall calculate a facility-specific emissions

factor according to Equation 50-1 for performance test and 50-1a for continuous monitors of this section:

$$EF_{N_2O} = \frac{\sum_1^n \frac{C_{N_2O} * 1.826 \times 10^{-6} * Q}{P}}{n} \quad \text{Equation 50-1}$$

$$EF_{N_2O} = \frac{C_{N_2O} * 1.826 \times 10^{-6} * Q}{P} \quad \text{Equation 50-1a}$$

Where:

- EF_{N_2O} = Average facility-specific N_2O emissions factor without using N_2O abatement technology (kg N_2O generated/tonne adipic acid produced).
- C_{N_2O} = average N_2O concentration during the performance test or average hourly concentrations for continuous process monitors (ppm N_2O).
- 1.862×10^{-6} = Conversion factor (kg/dSm³-ppm N_2O).
- Q = average volumetric flow rate of effluent gas per test run during the performance test or average hourly readings for continuous monitor (dSm³/hr).
- P = average production rate during the performance test or the average hourly production rate for continuous monitors during the period (tonnes adipic acid produced/hr).
- n = Number of test runs.

(d) If applicable, the person shall determine the destruction efficiency for each N_2O abatement technology used at the facility according to paragraphs (d)(1), (d)(2), (d)(3) or (d)(4) of this section.

- (1) Use the manufacturer's specified destruction efficiency.
- (2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. The person shall document how process knowledge was used to determine the destruction efficiency.
- (3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.
- (4) Calculate the destruction efficiency by the use of continuous monitors on the controlled and uncontrolled emissions.

- (e) If applicable, the person shall determine the abatement factor for each N₂O abatement technology used at the facility. The abatement factor is calculated for each adipic acid facility according to Equation 50-2 of this section.

$$AF = \frac{P_{a \text{ Abate}}}{P_a} \quad \text{Equation 50-2}$$

Where:

- AF = Abatement factor of N₂O abatement technology (fraction of production in the testing period that abatement technology is operating).
- P_{a Abate} = adipic acid production in the testing period during which N₂O abatement was used (tonne acid produced).
- P_a = Total adipic acid production in the testing period (tonne acid produced).
- (f) The person shall determine the annual amount of adipic acid produced and the annual adipic acid production during which N₂O abatement is operating.
- (g) The person shall calculate annual adipic acid production process emissions of N₂O by multiplying the emissions factor (determined using Equation 50-1 or 50-1a of this section) by the adipic acid production for each period and accounting for N₂O abatement, according to Equation 50-3 of this section:

$$N_2O = \sum_{i=1}^N \frac{EF_{N20i} * P_{ai} * (1 - (DF_i * AF_i))}{1000} \quad \text{Equation 50-3}$$

Where:

- N₂O = Annual N₂O mass emissions from adipic acid production (tonnes).
- EF_{N20i} = Facility-specific N₂O emissions factor for the period without abatement technology (kg N₂O generated/tonne adipic acid produced).
- P_{ai} = Adipic acid produced in the period (tonnes).
- DF_i = Destruction efficiency of N₂O abatement technology in the period (abatement device destruction efficiency, per cent of N₂O removed from air stream).
- AF_i = Abatement factor of N₂O abatement technology in the period (fraction of period that is production abatement technology is operating).
- 1000 = Conversion factor (kg/tonne).
- N = Number of different periods in the year. For performance test, the period would be the time between each test (e.g., N is 1 year if performance test conducted annually). For

continuous monitors, N would be the number of months in the year (or more), with P_{ai} , $EF_{N_2O_i}$, DF_i and AF_i to be calculated for each month.

ON.54 Sampling, Analysis, and Measurement Requirements

(a) The person shall conduct a new performance test and calculate a new facility-specific emissions factor according to the frequency specified in paragraphs (a)(1) of this section, or use continuous monitors to calculate a facility-specific emissions factor and destruction efficiency according to paragraphs (a)(2) of this section.

(1) Performance Test

- (i) Conduct the performance test annually or
- (ii) Conduct the performance test when the adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(2) Continuous Process Monitors

- (i) Continuous process monitors shall be used to determine the uncontrolled emissions and the controlled N_2O emissions to derive an N_2O emission factor and abatement system destruction factor.
- (ii) The continuous process monitors shall be operated in accordance with quality assurance and quality control programs.

(b) The person shall measure the N_2O concentration during the performance test using one of the following methods:

- (1) Any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 5),
- (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used

(c) The person shall determine the production rate(s) during the performance test and the annual adipic acid production according to either of the following methods:

- (1) Direct measurement (such as using flow meters or weigh scales).
- (2) Existing plant procedures used for accounting purposes (such as sales records).

(d) The person shall conduct all required performance tests according to the methods in ON.54(b). For each test, the facility shall prepare an emissions factor determination report that shall include the following items.

- (1) Analysis of samples, determination of emissions, and raw data.
 - (2) All information and data used to derive the emissions factor.
 - (3) The production rate(s) during the performance test and how each production rate was determined.
- (e) The person shall determine the monthly adipic acid production quantity and the monthly adipic acid production during which N₂O abatement technology is operating according to the methods in paragraphs (c)(1) or (c)(2) of this section.
- (f) The person shall determine the annual adipic acid production quantity and the annual adipic production quantity during which N₂O abatement technology is operating by summing the respective monthly adipic acid production quantities. The equipment used to measure the production quantity shall:
- (1) be calibrated according to the manufacturer's instructions; and
 - (2) be maintained to achieve an accuracy of plus or minus 5%.

ON.55 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.54, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.54 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (1) When data determined on the basis of a performance test required by ON.54 is missing, conduct a new performance test;
 - (2) When the missing data is not data prescribed in a performance test and concerns carbon content, temperature, pressure or gas concentration, the person shall:
 - (i) Determine the sampling or measurement rate that was used using the following Equation 50-4:

$$R = Q_{SAct}/Q_{SRequired} \quad \text{Equation 50-4}$$

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

Q_{SRequired} = Quantity of samples or measurements required under ON.54

- (ii) Replace the missing data as follows`
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (3) When the missing data concerns adipic acid production or gas flow rate, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (4) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.80 Ammonia Production

ON.81 Activity Definition

For the purposes of this standard quantification method:

“Ammonia production” has the same meaning as in the Regulation.

“Person” means a person that engages in ammonia production.

ON.82 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.80 – ON.85, in an emission report prepared for a calendar year in respect of ammonia production at a facility:

- (a) CO₂ process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material following the requirements in this section (tonnes).
- (b) Annual quantity of each type of feedstock consumed for ammonia manufacturing (expressed in Sm³ for liquid feedstock or kilolitres for liquid feedstock or tonnes for solid feedstock).
- (c) If a CEMS is not used to measure emissions, report the following information:
 - (1) Whether carbon content for each feedstock is based on reports from the supplier or analysis of carbon content.
 - (2) If a facility uses gaseous feedstock, the annual weighted average carbon content of each type of gaseous feedstock (kg C per kg of feedstock).
 - (3) If a facility uses liquid feedstock, the annual weighted average carbon content of each type of liquid feedstock (kg C per kilolitre of feedstock).
 - (4) If a facility uses solid feedstock, the annual weighted average carbon content of each type of solid feedstock (kg C per kg of feedstock).
- (d) Annual urea production (tonnes).

Production Parameters

- (e) Annual ammonia production (tonnes).

ON.83 Calculating GHG Emissions

The person shall calculate and report the annual process CO₂ emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

- (a) Calculate and report the process CO₂ emissions by operating and maintaining CEMS according to Calculation Methodology 4 specified in ON.23 and all associated requirements for methodology 4 in ON.20.

(b) Calculate and report process CO₂ emissions using the procedures in paragraphs (b)(1) through (b)(6) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) Gaseous feedstock. The person shall calculate the CO₂ process emissions from gaseous feedstock according to Equation 80-1 of this section:

$$CO_{2,G,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n * \frac{MW}{MVC} \right) * 0.001 \quad \text{Equation 80-1}$$

Where:

- CO_{2,G,k} = Annual CO₂ emissions arising from feedstock consumption (tonnes).
- Fdstk_{n,k} = Volume of the gaseous' feedstock used in month n (Rm³ of feedstock) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock used in the month n as kg feedstock and replace the term “MW/MVC” with “1”.
- CC_n = Carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock), determined according to ON.84(c).
- MW = Molecular weight of the gaseous feedstock (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the above Fdstk_{n,k} (Rm³/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to tonnes.
- k = Processing unit.
- n = Number of month

(2) Liquid feedstock. The person shall calculate, from each ammonia manufacturing unit, the CO₂ process emissions from liquid feedstock according to Equation 80-2 of this section:

$$CO_{2,L,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n \right) * 0.001 \quad \text{Equation 80-2}$$

Where:

- CO_{2,L,k} = Annual CO₂ emissions arising from feedstock consumption (tonnes).
- Fdstk_{n,k} = Volume of the liquid feedstock used in month n (kilolitres of feedstock). If a mass flow meter is used, measure the feedstock used in month n as kg of feedstock and measure the carbon content of feedstock in kg C per kg of feedstock.

- CC_n = Carbon content of the liquid feedstock, for month n as determined according to ON.84(c). (kg of C per kilolitre of feedstock when feedstock consumption is measured in kilolitres or kg of C per kg of feedstock when feedstock consumption is measured in kg.
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to tonnes.
- k = Processing unit.
- n = Number of months

- (3) Solid feedstock. The person shall calculate, from each ammonia manufacturing unit, the CO₂ process emissions from solid feedstock according to Equation 80-3 of this section:

$$CO_{2,S,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n \right) * 0.001 \quad \text{Equation 80-3}$$

Where:

- $CO_{2,S,k}$ = Annual CO₂ emissions arising from feedstock consumption (tonnes).
- $Fdstk_{n,k}$ = Mass of the solid feedstock used in month n (kg of feedstock).
- CC_n = Carbon content of the solid feedstock, for month n, (kg C per kg of feedstock), determined according to ON.84(c).
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to tonnes.
- k = Processing unit.
- n = Number of month.

- (4) The person shall calculate the annual process CO₂ emissions from each ammonia processing unit k at the facility summing emissions, as applicable from Equations 80-1, 80-2, and 80-3 of this section using Equation 80-4.

$$E_{CO_2k} = CO_{2,G,k} + CO_{2,S,k} + CO_{2,L,k} \quad \text{Equation 80-4}$$

Where:

- E_{CO_2k} = Annual CO₂ emissions from each ammonia processing unit k (tonnes).
- k = Processing unit.

- (5) The person shall determine the combined CO₂ emissions from all ammonia processing units at the facility using Equation 80-5 of this section.

$$CO_2 = \sum_{k=1}^n E_{CO_2k}$$

Equation 80-5

Where:

- CO₂ = Annual combined CO₂ emissions from all ammonia processing units (tonnes).
- E_{CO₂k} = Annual CO₂ emissions from each ammonia processing unit (tonnes).
- k = Processing unit.
- n = Total number of ammonia processing units.

- (c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with Calculation Methodology 4 in ON.23, then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The person shall report under this section the combined stack emissions according to Calculation Methodology 4 in ON.23 and all associated requirements for Calculation Methodology 4 in ON.20.

ON.84 Sampling, Analysis, and Measurement Requirements

- (a) The person shall continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.
- (b) The person shall document the procedures used to ensure the accuracy of the estimates of feedstock consumption.
- (c) The person shall determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from the supplier. As an alternative to using supplier information on carbon contents, the person can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods.
 - (1) Any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 5),
 - (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

- (d) Calibrate all oil and gas flow meters (except for gas billing meters) and perform oil tank measurements according to the monitoring and QA/QC requirements specified in section ON.25(b)(3).
- (e) If CO₂ from ammonia production is used to produce urea at the same facility, the person shall determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). The person shall document the procedures used to ensure the accuracy of the estimates of urea produced.
- (f) The person shall measure the ammonia produced. The equipment used to measure the production shall be:
 - (1) calibrated according to the manufacturer's instructions; and
 - (2) maintained an accuracy of plus or minus 5%.

ON.85 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.84, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.84 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
 - (1) When data determined on the basis of a performance test required by ON.84 is missing, conduct a new performance test;
 - (2) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
 - (i) Determine the sampling or measurement rate using the following Equation 80-6:

$$R = Q_{SAct}/Q_{SRequired} \qquad \text{Equation 80-6}$$

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

Q_{SRequired} = Quantity of samples or measurements required under ON.84

- (ii) Replace the missing data as follows,
 - (A) If R ≥ 0.9: replace the missing data by the arithmetic mean of the sampling or measurement data from

- immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (3) When the missing data concerns raw material quantity, ammonia production or waste gas consumption, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (4) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.180 Carbonate Use

ON.181 Activity Definition

For the purposes of this standard quantification method:

“Carbonate use” has the same meaning as in the Regulation.

“Person” means a person that engages in carbonate use.

ON.182 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.180 – ON.185, in an emission report prepared for a calendar year in respect of carbonate use at a facility:

- (a) Annual CO₂ emissions from miscellaneous carbonate use (tonnes).
- (b) If the person followed the calculation methodology contained in ON.183(a), the person shall report the following information:
 - (1) Annual carbonate consumption by carbonate type (tonnes).
 - (2) Annual calcination fractions used in calculations.
- (c) If the person followed the calculation methodology contained in ON.183(b), the person shall report the following information:
 - (1) Annual carbonate input by carbonate type (tonnes).
 - (2) Annual carbonate output by carbonate type (tonnes).

ON.183 Calculating GHG Emissions

The person shall determine CO₂ process emissions from carbonate use in accordance with the procedures specified in either paragraph (a) or (b) of this section.

- (a) Calculate the process emissions of CO₂ using calcination fractions with Equation 180-1 of this section.

$$E_{CO_2} = \sum_{i=1}^n (M_i \times EF_i \times F_i) \quad \text{Equation 180-1}$$

Where:

- E_{CO_2} = Annual CO₂ mass emissions from consumption of carbonates (tonnes).
- M_i = Annual mass of carbonate type i consumed (tonnes).
- EF_i = Emission factor for the carbonate type i, as specified in Table 180-1 to this section, tonnes CO₂/tonne carbonate consumed.

- F_i = Fraction calcination achieved for each particular carbonate type i (weight fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.
- n = Number of carbonate types.

- (b) Calculate the process emissions of CO₂ using actual mass of output carbonates with Equation 180-2 of this section.

$$E_{CO_2} = \left[\sum_{k=1}^m (M_k \times EF_k) - \sum_{j=1}^n (M_j \times EF_j) \right]$$

Equation 180-2

Where:

- E_{CO_2} = Annual CO₂ mass emissions from consumption of carbonates (tonnes).
- M_k = Annual mass of input carbonate type k (tonnes).
- EF_k = Emission factor for the input carbonate type k , as specified in Table 180-1 of this section (tonnes CO₂/tonne carbonate).
- M_j = Annual mass of output carbonate type j (tonnes).
- EF_j = Emission factor for the output carbonate type j , as specified in Table 180-1 of this section (tonnes CO₂/tonne carbonate).
- m = Number of input carbonate types.
- n = Number of output carbonate types.

ON.184 Sampling, Analysis, and Measurement Requirements

- (a) The annual mass of carbonate consumed (for Equation 180-1 of this section) or carbonate inputs (for Equation 180-2 of this section) shall be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.
- (b) The annual mass of carbonate outputs (for Equation 180-2 of this section) shall be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.
- (c) If the person followed the procedures of ON.183(a), rather than assuming a calcination fraction of 1.0, the person may determine, on an annual basis, the calcination fraction for each carbonate consumed using one of the following:
- (1) Any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 5);
 - (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry

standard methods, noting where such methods are used and what methods are used.

ON.185 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.184, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.184 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
- (i) Determine the sampling or measurement rate using the following Equation 180-3:

$$R = Q_{SAct}/Q_{SRequired} \qquad \text{Equation 180-3}$$

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{SRequired}$ = Quantity of samples or measurements required under ON.184

- (ii) Replace the missing data as follows,
- (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
- (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns raw material consumption or carbonate consumption, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

Table 180-1—CO₂ Emission Factors for Common Carbonates

Mineral Name – Carbonate	CO ₂ Emission Factor (tonnes CO ₂ /tonne carbonate)
Limestone - CaCO ₃	0.43971
Magnesite - MgCO ₃	0.52197
Dolomite - CaMg(CO ₃) ₂	0.47732
Siderite - FeCO ₃	0.37987
Ankerite - Ca(Fe,Mg,Mn)(CO ₃) ₂	0.47572
Rhodochrosite - MnCO ₃	0.38286
Sodium Carbonate/Soda Ash – Na ₂ CO ₃	0.41492
Others	Facility specific factor to be determined through analysis or supplier information or using stoichiometric ratio

ON.90 Cement Production

ON.91 Activity Definition

For the purposes of this standard quantification method:

“cement production” has the same meaning as in the Regulation.

“Person” means a person that engages in cement production.

ON.92 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.90 – ON.95, in an emission report prepared for a calendar year in respect of cement production at a facility:

- (a) Annual CO₂ process emissions (excluding emissions from fuel combustion) in tonnes.
- (b) Report the following information if the process CO₂ emissions are calculated according to the procedures specified in ON.93(b)(1):
 - (1) Monthly plant specific clinker emission factors (tonnes CO₂/tonnes clinker).
 - (i) Monthly quantities of clinker produced (tonnes).
 - (ii) Monthly total calcium content of clinker, expressed as calcium oxide (CaO) (weight fraction, tonne CaO/tonne clinker).
 - (iii) Monthly total magnesium content of clinker, expressed as magnesium oxide (MgO) (weight fraction, tonne MgO/tonne clinker).
 - (iv) Monthly non-calcined calcium oxide content of clinker, expressed as CaO (weight fraction, tonne CaO/tonne clinker).
 - (v) Monthly non-calcined magnesium oxide content of clinker, expressed as MgO (weight fraction, tonne MgO/tonne clinker).
 - (vi) Monthly quantity of non-carbonate raw materials entering the kiln (tonnes).
 - (2) Quarterly cement kiln dust (CKD) emission factor (tonne CO₂/tonne CKD not recycled back to kilns).
 - (i) Quarterly quantity of CKD not recycled back to kilns (tonnes).
- (c) Annual CO₂ process emissions from organic carbon oxidation (tonnes) and the following information if the process CO₂ emissions are calculated according to the procedures specified in ON.93(b)(2):
 - (1) Amount of raw material consumed in the report year (tonnes).
 - (2) Annual organic carbon content of raw material (weight. fraction).

- (d) Annual CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methodology and reporting requirements specified in ON.93(c) (tonnes).

Production Parameters

- (e) Annual clinker production, and quantity of gypsum and limestone added as mineral additives to the clinker at the facility (tonnes).

ON.93 Calculation of GHG Emissions from Kilns

- (a) Determine CO₂ emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
- (1) Calculate the total process and combustion CO₂ emissions from all the kilns using a continuous emissions monitoring system (CEMS) as specified in Calculation Methodology 4 in ON.23 and combustion CO₂ emissions from all the kilns using the calculation methodologies specified in paragraph (c) of this section.
 - (2) Calculate the sum of CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraphs (b) and (c) of this section.
- (b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-1).

$$E_{\text{CO}_2\text{-P}} = E_{\text{CO}_2\text{-C}} + E_{\text{CO}_2\text{-F}} \quad \text{Equation 90-1}$$

Where:

- $E_{\text{CO}_2\text{-P}}$ = Annual process CO₂ emissions, tonnes/year.
 $E_{\text{CO}_2\text{-C}}$ = Annual process CO₂ emissions from calcination, tonnes/year.
 $E_{\text{CO}_2\text{-F}}$ = Annual process CO₂ emissions from feed oxidation, tonnes/year.

- (1) Calcination Emissions. Calculate CO₂ process emissions from calcination using Equation 90-2 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$E_{\text{CO}_2\text{-C}} = \sum_{m=1}^{12} [Q_{\text{Cli},m} \times EF_{\text{Cli},m}] + \sum_{q} [Q_{\text{CKD},q} \times EF_{\text{CKD},q}]$$

Equation 90-2

Where:

- E_{CO_2-C} = Annual process CO₂ emissions from calcination, tonnes.
 $Q_{Cli,m}$ = Quantity of clinker produced in month m, tonnes.
 $EF_{Cli,m}$ = CO₂ emission factor for clinker in month m, computed as specified in paragraph (b)(1)(i) of this section, tonnes CO₂/tonne clinker.
 $Q_{CKD,q}$ = Quantity CKD not recycled to kilns in quarter q, tonnes.
 $EF_{CKD,q}$ = CO₂ emission factor for CKD not recycled to the kilns, computed as specified in paragraph (b)(1)(ii) of this section, tonnes CO₂/tonne CKD.

- (i) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cli}) for each month based on monthly measurements of the weight fractions of calcium (as CaO) and magnesium (as MgO) content in the clinker and in the non-carbonate raw materials entering the kiln, using Equation 90-3,.

$$EF_{Cli} = (CaO_{Cli} - CaO_f) \times 0.785 + (MgO_{Cli} - MgO_f) \times 1.092 \quad \text{Equation 90-3}$$

Where:

- EF_{Cli} = Monthly CO₂ emission factor for clinker, tonne CO₂/tonne clinker
 CaO_{Cli} = Monthly total calcium content of clinker expressed as calcium oxide, tonne CaO/tonne clinker.
 CaO_f = Monthly non-calcined calcium oxide content of clinker, tonne CaO/tonne clinker.
 MgO_{Cli} = Monthly total magnesium content of clinker expressed as magnesium oxide, tonne MgO/tonne clinker.
 MgO_f = Monthly non-calcined magnesium oxide content of clinker, tonne MgO/tonne clinker.
0.785 = Ratio of molecular weights of CO₂ to CaO
1.092 = Ratio of molecular weights of CO₂ to MgO

- (ii) CKD Emission Factor. If CKD is generated and not recycled back to the kilns, then calculate a plant-specific CKD emission factor based on quarterly sampling. The CKD emission factor shall be calculated using Equation 90-4.

$$EF_{CKD} = (CaO_{CKD} - CaO_f) \times 0.785 + (MgO_{CKD} - MgO_f) \times 1.092 \quad \text{Equation 90-4}$$

Where:

- EF_{CKD} = Quarterly CO₂ emission factor for CKD not recycled to the kilns, tonne CO₂/tonne CKD.

- CaO_{CKD} = Quarterly total calcium oxide content of CKD not recycled to the kilns, tonne CaO/tonne CKD.
- CaO_f = Quarterly non-calcined calcium oxide content of CKD not recycled to the kilns, tonne CaO/tonne CKD.
- MgO_{CKD} = Quarterly total magnesium oxide content of CKD not recycled to the kilns, tonne MgO/tonne CKD.
- MgO_f = Quarterly non-calcined magnesium oxide content of CKD not recycled to the kilns, tonne MgO/tonne CKD.
- 0.785 = Ratio of molecular weights of CO₂ to CaO
- 1.092 = Ratio of molecular weights of CO₂ to MgO

(2) Organic Carbon Oxidation Emissions. Calculate CO₂ process emissions from the total organic content in raw materials by using Equation 90-5.

Equation 90-5

$$E_{CO_2-RM} = TOC_{RM} \times RM \times 3.664$$

Where:

- E_{CO2-RM} = Annual process CO₂ emissions from raw material oxidation, tonnes.
- TOC_{RM} = Total organic carbon content in raw material (weight fraction), measured using the method in ON.94(b) or using a default of 0.002 (0.2%).
- RM = Amount of raw material consumed (tonnes/year).
- 3.664 = Ratio of molecular weights of carbon dioxide to carbon.

(c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O emissions from stationary fuel combustion in accordance with the calculation methodologies specified in ON.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO₂ emissions from fossil fuels using Calculation Methodology 1 in ON.23. "Pure" means that the biomass-derived fuels account for at least 97 per cent of the total amount of carbon in the fuels burned.

Cement plants that report CO₂ emissions from kilns using continuous emissions monitoring system under ON.93(a)(1) may report:

- (1) Fuel combustion CO₂ emissions in kilns by subtracting the total emissions calculated using ON.93(a)(1) from the process CO₂ emissions calculated using ON.93(b); or
- (2) Fuel combustion CO₂ emissions in kilns using Calculation Methodology 1 in ON.23 and fuel sampling based on the same plant techniques used for accounting purposes .

ON.94 Sampling, Analysis, and Measurement Requirements

- (a) Determine the monthly plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in clinker using one of the following:
- (1) Any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 5);
 - (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

The monitoring shall be conducted either daily from clinker drawn from the exit of the kiln or monthly from clinker drawn from bulk storage.

- (b) Determine quarterly the plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in CKD using one of the following:
- (1) Any of the analytical methods listed in the Technical Reference Document section of this Guideline (section 5);
 - (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

The monitoring shall be conducted either daily from CKD samples drawn from the exit of the kiln or quarterly from CKD samples drawn from bulk storage.

- (c) Determine monthly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to clinker by chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.
- (d) Determine quarterly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to CKD by chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.
- (e) Determine monthly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in clinker by chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.
- (f) Determine quarterly the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in CKD by chemical analysis of feed material using documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.

- (g) Determine annually the total organic carbon contents of raw materials using ASTM C114, an equivalent industry method for total organic carbon determination in raw mineral material, or use a default value of 0.002. The analysis shall be conducted on sample material drawn from bulk raw material storage for each category of raw material.
- (h) The quantity of clinker produced shall be determined monthly by either:
 - (1) Direct weight measurement using the same plant techniques used for accounting purposes, such as reconciling weigh hoppers or belt weigh feeders measurements against inventory measurements, or
 - (2) Direct measurement of raw kiln feed and application of a kiln-specific feed-to-clinker factor. Facilities that opt to use a feed to clinker factor shall verify the accuracy of this factor on a monthly basis.
- (i) The quantity of CKD not recycled back to the kiln shall be determined quarterly by either using the same plant techniques used for accounting purposes, such as direct weight measurement using weigh hoppers or belt weigh feeders, and/or material balances.
- (j) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, alumina, and non-carbonate raw material) shall be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
- (k) The quantity of limestone and gypsum blended with the clinker shall be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes.
- (l) Equipment used to measure the clinker, limestone and gypsum shall be:
 - (1) calibrated according to the manufacturer's instructions and
 - (2) maintained to achieve an accuracy of plus or minus 5%.

ON.95 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall using the methods prescribed in ON.94, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.94 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:

(1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:

(i) Determine the sampling or measurement rate using the following Equation 90-4:

$$R = Q_{SAct}/Q_{SRequired} \quad \text{Equation 90-4}$$

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{SRequired}$ = Quantity of samples or measurements required under ON.94

(ii) Replace the missing data as follows,

(A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;

(B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;

(C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;

(2) When the missing data concerns clinker production, the person shall use the first data estimated after the period for which the data is missing or use the maximum daily production capacity and multiply it by the number of days in the month;

(3) When the missing data concerns raw material consumption, the person shall use the first data estimated after the period for which the data is missing or use the maximum rate of raw materials entering the kiln and multiply by the number of days in the month;

(4) When the missing data concerns the quantity of dust, the quantity of gypsum or the quantity of limestone, the replacement data shall be generated from best estimates based on all of the data relating to the processes..

(5) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.100 Coal Storage

ON.101 Activity Definition

For the purposes of this standard quantification method:

“Coal storage” has the same meaning as in the Regulation.

“Person” means a person that engages in coal storage.

ON.102 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.100 – ON.105, in an emission report prepared for a calendar year in respect of coal storage at a facility:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:

(1) Total CH₄ emissions.

(b) Annual coal purchases (tons for U.S.; tonnes for Canada).

(c) Source of coal purchases:

(1) Coal basin.

(2) State/province.

(3) Coal mine type (surface or underground).

ON.103 Calculation of CH₄ Emissions

Calculate fugitive CH₄ emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

(a) For coal purchased from U.S. sources, calculate fugitive CH₄ emissions using Equation 100-1 and Table 100-1.

(b) For coal purchased from Canadian sources, calculate fugitive CH₄ emissions using Equation 100-1 and Table 100-2.

(c) For coal purchased from non-U.S. and non-Canadian sources, the person shall use either ON.103(a) or ON.103(b), whichever is the most applicable.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.6772 / 1,000 \quad \text{Equation 100-1}$$

Where:

- CH₄ = Fugitive emissions from coal storage piles for each coal category *i*, (tonnes CH₄ per year);
- PC_{*i*} = Purchased coal for each coal category *i* (tonnes per year);
- EF_{*i*} = Default CH₄ emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-2 (m³ CH₄ per tonne of coal);

0.6772 = Methane conversion factor to convert m³ to kg;
1,000 = Factor to convert kg to tonnes.

ON.104 Sampling, Analysis, and Measurement Requirements

(a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

ON.105 Procedures for Estimating Missing Data

When the missing data is relating to the total quantity of coal purchased, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

Table 100-1 - U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ m³ per Tonne)

Coal Origin Coal Basin	Coal Origin States	Coal Mine Type Surface Post-Mining Factors	Coal Mine Type Underground Post-Mining Factors
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987
N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591

Coal Origin Coal Basin	Coal Origin States	Coal Mine Type Surface Post-Mining Factors	Coal Mine Type Underground Post-Mining Factors
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Source:

Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005

April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH₄ Emission Factors (ft³ per Short Ton; converted to m³ per tonne). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-2. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ m³ per tonne)

Coal Origin Province	Coal Origin Coalfield	Coal Mine Type Surface Post-Mining Factors	Coal Mine Type Underground Post-Mining Factors
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923

Source:

Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Dartmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).

ON.260 Copper and Nickel Production

ON.261 Activity Definition

For the purposes of this standard quantification method:

“Copper and nickel production” has the same meaning as in the Regulation.

“Person” means a person that engages in copper and nickel production.

ON.262 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.260 – ON.265, in an emission report prepared for a calendar year in respect of copper and nickel production at a facility:

- (a) Annual emissions of CO₂ at the facility level (tonnes).
- (b) Annual quantities of each carbonate flux reagent used (tonnes).
- (c) Fractional purity of each carbonate flux reagent used (tonnes carbonate/tonnes reagent).
- (d) Annual quantities of other reducing agents used (tonnes).
- (e) Carbon content of other reducing agent used or material used for slag cleaning (tonnes C/tonne reducing agent or material for slag cleaning).
- (f) Annual quantity of ore processed (tonnes).
- (g) Carbon content of ore processed (tonnes C/tonne ore).

ON.263 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) through (d) of this section.

- (a) Calculate CO₂ emissions from carbonate flux reagents using Equation 260-1.

$$E_{cf} = Q_{ls} \times f_{ls} \times \left(\frac{44}{100} \right) + Q_d \times f_d \times \left(\frac{88}{184} \right) \quad \text{Equation 260-1}$$

Where:

- E_{cf} = Annual CO₂ emissions from carbonate flux reagents (tonnes);
- Q_{ls} = Annual quantity of limestone consumed (tonnes);
- f_{ls} = Fractional purity of limestone (tonnes CaCO₃/tonnes of material);
- 44/100 = Stoichiometric conversion factor from CaCO₃ to CO₂;
- Q_d = Annual quantity of dolomite consumed (tonnes);
- f_d = Fractional purity of dolomite (tonnes CaCO₃·MgCO₃/tonnes of material);

88/184 = Stoichiometric conversion factor from $\text{CaCO}_3 \cdot \text{MgCO}_3$ to CO_2 .

- (b) Calculate CO_2 emissions from other reducing agents or material used in slag cleaning using Equation 260-2.

$$E_{ra} = Q_a \times C_a \times 3.664 \quad \text{Equation 260-2}$$

Where:

- E_{ra} = Annual CO_2 emissions from other reducing agents or material used for slag cleaning (tonnes);
 Q_a = Annual quantity of other reducing agents or material used for slag cleaning (tonnes);
 C_a = Carbon content of other reducing agents or material used for slag cleaning (tonnes C/tonne of reducing agent or material used for slag cleaning);
3.664 = ratio of molecular weights, carbon dioxide to carbon.

- (c) Calculate CO_2 emissions from release of carbon from metal ores (including releases from solvent extraction) using Equation 260-3.

$$E_{ore} = Q_{ore} \times C_{ore} \times 3.664 \quad \text{Equation 260-3}$$

Where:

- E_{ore} = Annual process CO_2 emissions from metal ore, tonnes
 Q_{ore} = Annual quantity of nickel or copper metal ore consumed (tonnes);
 C_{ore} = Carbon content of nickel or copper metal ore (tonnes C/tonne of nickel or copper ore);
3.664 = ratio of molecular weights, carbon dioxide to carbon.

- (d) Calculate CO_2 emissions from carbon electrode consumption in electric arc furnaces (EAFs) using Equation 260-4.

$$E_{ce} = Q_{ce} \times C_{ce} \times 3.664 \quad \text{Equation 260-4}$$

Where:

- E_{ce} = Annual CO_2 emissions from carbon electrode consumption in EAFs (tonnes);
 Q_{ce} = Quantity of carbon electrodes consumed (tonnes);
 C_{ce} = Carbon content of carbon electrodes (tonnes C/tonne carbon electrodes);
3.664 = ratio of molecular weights, carbon dioxide to carbon.

ON.264 Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for

accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following:
 - (1) Any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 5);
 - (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (b) Obtain carbon content of the materials, including carbon electrodes, from the vendor or supplier.

ON.265 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.264, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.264 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
 - (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
 - (i) Determine the sampling or measurement rate using the following Equation 260-5:

$$R = Q_{SAct}/Q_{SRequired} \qquad \text{Equation 260-5}$$

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{SRequired}$ = Quantity of samples or measurements required under ON.264

- (ii) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from

- immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns raw material consumption, carbonate consumption, reducing agent consumption, carbon electrode consumption, recycled material consumption or copper production, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.40 Electricity Generation

ON.41 Activity Definition

For the purposes of this standard quantification method:

“Electricity generation” has the same meaning as in the Regulation.

“Person” means a person that engages in electricity generation.

ON.42 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.40 – ON.45, in an emission report prepared for a calendar year in respect of electricity generation at a facility:

- (a) Annual greenhouse gas emissions in tonnes, reported as follows:
 - (1) Total CO₂ emissions for fossil fuels, reported by fuel type.
 - (2) Total CO₂ emissions for all biomass fuels combined.
 - (3) Total CH₄ emissions for all fuels combined.
 - (4) Total N₂O emissions for all fuels combined.
- (b) Annual fuel consumption:
 - (1) For gases, report in units of standard cubic meters.
 - (2) For liquids, report in units of kilolitres.
 - (3) For non-biomass solids, report in units of tonnes.
 - (4) For biomass-derived solid fuels, report in units of bone dry tonnes.
- (c) Annual weighted average carbon content of each fuel, if used to compute CO₂ emissions as specified in ON.43.
- (d) Annual weighted average high heating value of each fuel, if used to compute CO₂ emissions as specified ON.43.
- (e) The nameplate generating capacity in megawatts (MW) and net power generated in the calendar year in megawatt hours (MWh).
- (f) For each cogeneration unit,
 - (1) indicate whether topping or bottoming cycle,
 - (2) total thermal output including any output used for electricity generation, in MJ;
 - (3) useful thermal output excluding any energy used for electricity generation, in MJ,
 - (4) Where useful thermal output is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ.

- (5) Where supplemental firing has been applied to support electricity generation, report this purpose and fuel consumption by fuel type using the units in ON.42(b).
- (g) Process CO₂ emissions from acid gas scrubbers and acid gas reagent.
- (h) Fugitive emissions of each of the HFCs in Schedule 1 of the Regulation from cooling units that support power generation.
- (i) Fugitive CO₂ emissions from geothermal facilities.
- (j) Fugitive CH₄ emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section ON.100.
- (k) An attestation signed by the person or, where the person is not a natural person, an individual that is authorized to sign on behalf of the person confirming the total quantity of petroleum products received at the facility in the year from each supplier that supplied petroleum to the facility during the year.
- (l) For a facility that has no access to natural gas, the energy input from the combustion of each non-biomass fuel in electricity generation or cogeneration, expressed in giga-joules.
- (m) The electricity that is transmitted to the IESO controlled grid or to the distribution system of a distributor in megawatt hours (MWh).

Production Parameters

- (n) Where a facility has purchased electricity generated at another facility and where the purchased electricity is not transferred from the IESO controlled grid or from a distribution system of a distributor:
 - (1) The amount of purchased electricity in megawatt hours (MWh).
 - (2) The fraction of non-biomass energy input into the electricity generation at the facility that is generating the electricity

ON.43 Calculation of Greenhouse Gas Emissions

- (a) Calculation of CO₂ Emissions. The person shall use CEMS to measure CO₂ emissions if required to operate a CO₂ CEMS with flow monitors by any other federal or provincial regulation. A person not required to operate a CEMS by another regulation may use either CEMS or the calculation methodologies specified in paragraphs (a)(1) through (a)(7). The person using CEMS to determine CO₂ emissions shall comply with the provisions in Calculation Methodology 4 of ON.23.
 - (1) Natural Gas, and fuels in Table 20-1a. For electricity generating units combusting natural gas or the fuels listed in Table 20-1a, use methods in accordance with ON.23.
 - (2) Coal or Petroleum Coke. For electricity generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and Calculation Methodology 3 in section ON.23.

- (3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases that are not listed in Table 20-1a. For electricity generating units combusting middle distillates, gasoline, use Calculation Methodology 2 or 3 in accordance with ON.23.
- (4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electricity generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in ON.30.
- (5) Landfill Gas, Biogas, or Biomass. For electricity generating units combusting landfill gas, biogas, or biomass, use methods in accordance with ON.23.
- (6) Municipal Solid Waste. Electricity generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in ON.20 Table 20-7, and the Calculation Methodology 2 in section ON.23 provided the facility is not subject to the Regulation. If the facility is subject to the Regulation, the person shall use CEMS to measure CO₂ emissions in accordance with Calculation Methodology 4 of ON.23, or calculate emissions using steam flow and a CO₂ emission factor according to the provisions of ON.23.
- (7) Start-up Fuels. The persons of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO₂ emissions from fossil fuel combustion using one of the following methods. Malfunction means the unplanned outage of equipment; breakdown of equipment; or failure of equipment to operate normally, associated with the operation of a combustion device for an electricity generation unit(s). It does not include normal changes in operation conditions such as variations in combustion temperature, oxygen levels or moisture content of the fuel.
 - (i) The default emission factors from Tables 20-1a, 20-2, 20-3, 20-5 or 20-7, and default HHV from Tables 20-1 or 20-1a, as applicable, and Calculation Methodology 1 provided in section ON.23;
 - (ii) The measured heat content of the fuel and Calculation Methodology 2 provided in section ON.23;
 - (iii) The measured carbon content of the fuel and Calculation Methodology 3 provided in section ON.23; or
 - (iv) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section ON.30.
- (8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the person shall calculate CO₂ emissions as follows.

- (i) For co-fired electricity generators that burn only fossil fuels, CO₂ emissions shall be determined using one of the following methods:
 - (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section ON.23. The person using this method needs not report emissions separately for each fossil fuel.
 - (B) For units not equipped with a continuous emission system, calculate the CO₂ emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.
- (ii) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO₂ emissions shall be determined using one of the following methods:
 - (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section ON.23. The person using this method shall determine the portion of the total CO₂ emissions attributable to the biomass-derived fuel and portion of the total CO₂ emissions attributable to the fossil fuel using the methods specified in Calculation Methodology 4 of ON.23.
 - (B) For units not equipped with a continuous emission system, calculate the CO₂ emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of section ON.43(a).
- (b) Calculation of CH₄ and N₂O Emissions. The person shall use the methods specified in section ON.24 to calculate the annual CH₄ and N₂O emissions. For coal combustion, use the default CH and N₂O emission factor(s) in Table 20-6.
- (c) Calculation of CO₂ Emissions from Acid Gas Scrubbing. The person that uses acid gas scrubbers or adds an acid gas reagent to the combustion unit shall calculate the annual CO₂ emissions from these processes using Equation 40-1 if these emissions are not already captured in CO₂ emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times (CO_{2,MW} / Sorbent_{MW}) \quad \text{Equation 40-1}$$

Where:

- CO₂ = CO₂ emitted from sorbent for the report year, tonnes;
- S = Limestone or other sorbent used in the report year, tonnes;
- R = Ratio of moles of CO₂ released upon capture of one mole of acid gas;
- CO₂ _{MW} = Molecular weight of carbon dioxide (44);
- Sorbent _{MW} = Molecular weight of sorbent (if calcium carbonate, 100).

(d) Calculating Fugitive HFC Emissions from Cooling Units. The persons shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The person is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs, or from heating ventilation and air conditioning systems used for cooling of control rooms, offices and buildings at the facility.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HCF = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} - HFC_{\Delta capacity}$$

Equation 40-2

Where:

- HFC = Annual fugitive HFC emission, tonnes;
- HFC_{inventory} = The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
- HFC_{purchases/acquisitions} = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
- HFC_{sales/disbursements} = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.
- HFC_{Δcapacity} = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment. The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The person may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The person shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Service} = R_{recharge} - R_{Recover} \quad \text{Equation 40-2a}$$

$$HFC_{Install} = R_{new} - C_{new} \quad \text{Equation 40-2b}$$

$$HFC_{Retire} = C_{retire} - R_{retire} \quad \text{Equation 40-2c}$$

Where:

- HFC_{Install} = HFC emitted during initial charging/installation of the unit, kilograms;
- HFC_{Service} = HFC emitted during use and servicing of the unit for the report year, kilograms;
- HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
- R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
- C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
- R_{recharge} = HFC used to recharge the unit during maintenance and service, kilograms;
- R_{recover} = HFC recovered from the unit during maintenance and service, kilograms;
- C_{retire} = Nameplate capacity of the retired unit, kilograms; and
- R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO₂ Emissions from Geothermal Facilities. The person that operates geothermal electricity generating facilities shall calculate the fugitive CO₂ emissions using one of the following methods:

(1) Calculate the fugitive CO₂ emissions using Equation 40-3:

$$CO_2 = 7.14 \times Heat \times 0.001 \quad \text{Equation 40-3}$$

Where:

- CO₂ = CO₂ emissions, tonnes per year;
- 7.14 = Default fugitive CO₂ emission factor for geothermal facilities, kg per GJ
- Heat = Heat taken from geothermal steam and/or fluid, GJ/yr.
- 0.001 = Conversion factor from kilograms to tonnes.

(2) Calculate CO₂ emissions using source specific emission factor derived from measurements of carbon dioxide emissions and heat from geothermal steam.

ON.44 Sampling, Analysis, and Measurement Requirements

(a) CO₂, CH₄ and N₂O Emissions from Fuel Combustion. Persons using CEMS to estimate CO₂ emissions from fuel combustion shall comply with the requirements in Calculation Methodology 4 of ON.23. Persons using

methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, carbon content monitoring, and calculation methodologies specified in section ON.25.

- (b) CO₂ Emissions from Acid Gas Scrubbing. Persons that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the calendar year.
- (c) CO₂ Emissions from Geothermal Facilities. Persons that operate geothermal facilities shall measure the heat recovered from geothermal steam. If using a source specific emission factor instead of the default factor, the person shall update the source specific emission factors annually.

ON.45 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.44, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.44 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:

(1) When the missing data concerns sampled data, the person shall:

- (i) Determine the sampling or measurement rate using the following Equation 40-4:

$$R = Q_{SAct}/Q_{SRequired} \quad \text{Equation 40-4}$$

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{SRequired}$ = Quantity of samples or measurements required under ON.44

- (ii) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;

- (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns the quantity of energy transferred or a quantity of HFC, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
 - (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.60 Electricity Importation

ON. 61 Activity Definitions

“Balancing authority area” means the metered boundaries of the collection of generation, transmission, and loads of a balancing authority.

“Balancing authority” means an entity that maintains load-interchange-generation balance within a balancing authority area, and supports frequency in real time.

“Electricity generating facility” means a facility that generates electricity and includes one or more electricity generating units at the same location.

“Electricity generation unit” is the physically connected equipment that operate together to produce electricity at the same location.

“Electricity importer” means a person to whom section 9(3) para 1 of the Act applies.

“Electricity transaction” means the purchase, sale, import, export or exchange of electric power.

“Environmental attributes” means environmental premiums or tradeable instruments that are recognized as being derived from the generation of electricity.

“e-tag” means North American Energy Standards Board (NAESB) energy tag.

“Frequency in real time” means maintaining interconnection frequency at 60 hertz (Hz).

“Load interchange generation balance” means the balance between electricity demand and supply from resources within the Balancing Authority Area, and the flow of electricity into or out of the Balancing Authority Area on tie lines.

“Market participant” has the same meaning as in subsection 2(1) of the *Electricity Act, 1998*.

“Megawatt hour” or “MWh” means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

“Metered boundaries” means boundaries between adjacent balancing authority areas as defined by tie line meters that record the flow of energy between the balancing authority areas.

“Power contract” means an arrangement for the purchase of electricity including but not limited to power purchase agreements and tariff provisions.

“Regional Greenhouse Gas Initiative” or “RGGI” means the multi-state CO₂ emissions budget trading programs among participating states including: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

“Scheduled quantity” means the final amount listed in the e-tag that is approved by all balancing authority areas on the transmission path specified on the e-tag.

“Sink balancing authority area” means the balancing authority area that is the final destination of electricity on an e-tag.

“Sink” when used in a reference to electricity importation means imported electricity that is consumed in a given jurisdiction.

“Source balancing authority area” means the balancing authority area that is the origin of the electricity on an e-tag.

“Specified electricity generator” means an electricity generation unit, facility or new additional capacity outside of Ontario that started generation on or after January 1, 2017.

“Specified imported electricity” means electricity imported from a specified electricity generator which:

- (a) Is generated, at an output level at least equal to the scheduled quantity, by that generator at the time of the import transaction;
- (b) Is transmitted to Ontario;
- (c) Can be matched to a specific reported electricity transaction by evidence of the electricity importer’s rights to the scheduled quantity of electricity from that generator at the time of the import transaction through:
 - (1) Full or partial ownership of that generator by the electricity importer; or
 - (2) Its identification in a power contract between the electricity generator and the electricity importer, and
 - (3) Documented in an e-tag indicating the balancing authority area in which that generator is located as the source balancing authority area and Ontario as the sinking balancing authority area in accordance with ON.67. and
- (d) Has not had any environmental attributes associated with the specified imported electricity used to meet other regulatory requirements or, for the purposes of any voluntary or other market greenhouse gas reduction programs.

“Station service” does not include electrical power produced by a cogeneration unit for the purposes of a production process that is not an electricity power production process.

“Unspecified imported electricity” means imported electricity that is not specified imported electricity.

“Wheeled electricity” is imported electricity that is identified in the e-tag of a transaction that shows Ontario as an intermediate balancing authority on the transmission path and does not show Ontario as the sink balancing authority area.

ON.62 Greenhouse Gas Reporting Requirements

- (a) The electricity importer shall set out the following information, calculated for the calendar year using standard quantification methods ON.60– ON.65, in the report prepared for a calendar year in respect of electricity importation:
- (1) Total annual amount of greenhouse gas emissions in tonnes of CO₂e, calculated using the methods in ON.63 and ON.64.
 - (2) Annual quantity of specified and unspecified imported electricity used in the calculations contained in ON.63 and ON.64, expressed in MWh.
 - (3) The following information for each specified electricity generating facility from which the electricity importer imports electricity:
 - (i) The facility name;
 - (ii) The facility ID;
 - (iii) If applicable, the electricity generating unit ID.
 - (iv) The value of the emission factor (EF₁ or EF₂) for each generation unit.
 - (v) Annual scheduled quantity of specified imported electricity used in ON.63, expressed in MWh.
 - (vi) Annual scheduled quantity of specified imported electricity wheeled through Ontario, expressed in MWh.
 - (vii) Total annual amount of greenhouse gas emissions in tonnes of CO₂e, from the specified electricity generator.
 - (4) Report the following information for each balancing authority area from which unspecified electricity originated:
 - (i) The name of the balancing authority area;
 - (ii) Annual scheduled quantity of unspecified imported electricity used in ON.64, expressed in MWh; and
 - (iii) Annual scheduled quantity of unspecified imported electricity wheeled through Ontario, expressed in MWh.
 - (iv) Total annual amount of greenhouse gas emissions in tonnes of CO₂e, from unspecified electricity generation by balancing authority area.

ON.63 Calculation of Specified Imported Electricity

The electricity importer shall use one of the following equations, as applicable to calculate the emissions from specified imported electricity. All imported

electricity that meets the definition of specified imported electricity must be reported using these calculations.

- (a) Calculation Methodology 1. Use Equation 60-1 to calculate the total annual emissions of specified imported electricity.

$$E = \sum_{i=1}^n \left[\left(\frac{CO2_{ti}}{MWh_{ti}} \right) \times AF \times MWh_{imp_i} \right]$$

Equation 60-1

Where:

- E = Total annual emissions of specified imported electricity from specified electricity generators that report GHG emissions to the Climate Registry, the U.S.EPA using 40 CFR Part 75 or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33 expressed in tonnes CO₂e.
- CO₂_{ti} = Total annual non-biomass fuel related emissions from specified electricity generator i during the calendar year or the most recent data available, expressed in tonnes CO₂e as reported to The Climate Registry, U.S.EPA, U.S. Energy Information Administration or Environment Canada and where provided to the person.
- AF = Adjustment factor calculated in accordance with ON.66.
- MWh_{imp_i} = Scheduled quantity of specified imported electricity imported from specified electricity generator i, recorded in all the e-tags, expressed in MWh. calculated in accordance with ON.65
- MWh_{ti} = Total annual megawatt-hours of net power generated by specified electricity generator i during the calendar year or the most recent data available, expressed in MWh.
- n = the number of specified electricity generators
- EF₁ = emission factor 1, based on CO₂_{ti} / MWh_{ti} or Fuel_{fi}

- (b) Calculation Methodology 2. Use Equation 60-2 to calculate the total annual emissions of specified imported electricity.

$$E = \sum_{i=1}^n \sum_{f=1}^m (Fuel_{fi} \times HHV_{fi} \times EF_{fi} \times 0.001 \times AF \times \frac{MWh_{imp_i}}{MWh_{t_i}})$$

Equation 60-2

Where:

- E** = Total annual emissions from specified imported electricity from specified electricity generators that have not reported GHG emissions to the Climate Registry, the U.S.EPA using 40 CFR Part 75 or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33 expressed in tonnes CO₂e.
- Fuel_{fi}** = Total annual mass or volume of non-biomass fuel “f” combusted by specified electricity generator “i” expressed in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kilolitre for liquid fuel.
- HHV_{fi}** = Higher heating value of fuel “f” consumed for electricity production in GJ per unit of fuel, or measured in accordance with ON.25 for specified electricity generating facility “i”.
- EF_{fi}** = Fuel-specific default CO₂e emission factor for fuel “f” from ON.20 expressed in kg CO₂/GJ for specified electricity generating facility “i”.
- 0.001** = Conversion factor from kilograms to tonnes.
- AF** = Adjustment factor calculated in accordance with ON.66.
- MWh_{imp_i}** = Scheduled quantity of specified imported electricity from specified electricity generator i, recorded in all the e-tags expressed in MWh calculated in accordance with ON.65.
- MWh_{t_i}** = Total annual megawatt-hours of net power generated by specified electricity generator “i”.
- n** = the number of specified electricity generators
- m** = the number of fuels
- EF₂** = emission factor 2, based on Fuel_{fi} x HHV_{fi} x EF_{fi}/MWh_{t_i}

ON.64 Calculation of Unspecified Imported Electricity

The electricity importer shall use Equation 60-3 to calculate the emissions from unspecified imported electricity from each source balancing authority area that sinks in Ontario.

$$E = \sum_{i=1}^l \sum_{j=1}^n (MWh_{imp_ij} \times DEF_{ij} \times AF)$$

Equation 60-3

Where:

- E = Total annual emissions of unspecified imported electricity expressed in tonnes CO₂e.
- MWh_{imp_ij} = Annual scheduled quantity of unspecified imported electricity sinking in Ontario from each source balancing authority area “i” in period “j”, based on the e-tag expressed in MWh calculated in accordance with ON.65.
- DEF_{ij} = The default emission factor for period “j” from each source balancing authority area “i” published by the Ontario Ministry of Energy in the document entitled “Default Emissions Factors for Ontario’s Cap and Trade Program”.
- AF = Adjustment factor calculated in accordance with ON.66.
- i = The source balancing authority areas.
- j = the peak or off peak period as the case may be.
- l = The number of source balancing authority areas.
- n = The number of periods.

ON.65 Calculation of Imported Electricity

$$MWh_{imp_i} = \sum (MWh_{total_i} - MWh_{wheel_i})$$

Equation 60-4

$$MWh_{imp_ij} = \sum \sum (MWh_{total_ij} - MWh_{wheel_ij})$$

Equation 60-5

Where:

- MWh_{imp_j} = Annual Scheduled quantity of specified imported electricity imported into Ontario by the electricity importer, expressed in MWh.
- MWh_{imp_ij} = Annual Scheduled quantity of unspecified imported electricity imported into Ontario by the electricity importer, expressed in MWh.
- MWh_{Total_j} = Scheduled quantity of specified imported electricity recorded in each e-tag “i” that is imported into Ontario by the electricity importer, expressed in MWh.

- MWh_{wheel_i} = Scheduled quantity of specified imported electricity recorded in each e-tag “i” that is imported into Ontario by the electricity importer that is wheeled through Ontario, expressed in MWh.
- MWh_{Total_i} = Scheduled quantity of unspecified imported electricity recorded in each e-tag for source balancing authority “i” and peak/off period “j” that is imported into Ontario by the electricity importer, expressed in MWh.
- $MWh_{\text{wheel}_{ij}}$ = Scheduled quantity of unspecified imported electricity recorded in each e-tag for source balancing authority “i” and peak/off period “j” that is imported into Ontario by the electricity importer that is wheeled through Ontario, expressed in MWh.

ON.66 Calculation of adjustment factor

The electricity importer shall use one of the following methodologies, as applicable, to calculate the adjustment factor (AF) for equations 60-1, 60-2 and 60-3.

- (a) **Calculation methodology A:** The value of AF may be calculated using equation 60-5 if an electricity importer can demonstrate that the electricity imports that are the subject of the calculations in equations 60-1, 60-2 or 60-3, as applicable, meet one of the following criteria:
- (1) Import is from a designated jurisdiction;
 - (2) Import is from a U.S. State that is a member of RGGI
 - (3) Import is from a source balancing authority area that consists of U.S. States that are all members of the RGGI;
 - (4) Electricity import is from a source balancing authority area that includes U.S. States that are members of RGGI and U.S. States that are not members of RGGI, where the imported electricity can be demonstrated to have been generated in a US state that is a member of RGGI.

$$AF = \left(1 - \frac{P_{\text{Jurisdiction}}}{P_{\text{Ont}}}\right) \quad \text{Equation 60-5}$$

Where:

- AF = Adjustment factor
- $P_{\text{jurisdiction}}$ = Average sale price of emission allowances at auctions held during the calendar year by a designated jurisdiction or where the import is from a U.S. State that is a member of and offered allowances for sale in an auction carried out by the Regional

Greenhouse Gas Initiative in the calendar year (in U.S. dollars).

P_{Ont} = Average sale price of emission allowances at auctions held during the year by Ontario (in U.S dollars).

- (b) **Calculation Methodology B:** The value of AF shall be equal to one where an electricity importer is unable to demonstrate that the electricity imports that are the subject of the calculations in equations 60-1, 60-2 or 60-3, as applicable meet the criteria in subsections (1)-(4) of ON.66(a).
- (c) If a calculation for AF under ON.66(a) is less than zero, then the value of AF shall be equal to zero.

ON.67 Measurements and Documentation Requirements

(a) Meter Data Requirement

Importers of specified electricity shall retain metered generation data required to demonstrate that the electricity claimed by the electricity importer was generated by the facility or unit at the time the power was directly delivered.

The meter generation data shall be based on records from a revenue meter of the actual generation injected into the grid.

(b) E-tag documentation:

Electricity importers are identified as the Purchasing Selling Entity on the Physical Path of the e-tag before it enters Ontario.

All electricity importers shall retain records of the e-tag transactions which they scheduled with the pools and balancing authorities in the transmission path.

Electricity Importers shall retain e-tags indicating the source balancing authority area in which a specified electricity generator is located, the source balancing authority area that the unspecified electricity originated from, and Ontario as the sinking balancing authority area.

Electricity importers shall keep records of e-tags showing the full transmission path in the physical path table of a single or multiple NERC e-tag from the first point of receipt at the source balancing authority area to the final point of delivery at the sink balancing authority area.

ON.270 Ferroalloy Production

ON.271 Activity Definition

For the purposes of this standard quantification method:

“Ferroalloy production” has the same meaning as in the Regulation.

“Person” means a person that engages in ferroalloy production.

ON.272 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.270 – ON.275, in an emission report prepared for a calendar year in respect of ferroalloy production at a facility:

- (a) Process CO₂ emissions from each electric arc furnace (EAF) used for the production of any ferroalloy listed in ON.271.
- (b) Annual ferroalloy production (tonnes).

ON.273 Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart K Section 98.113.

ON.274 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance with U.S. EPA 40 CFR 98 Subpart K Section 98.114.

ON.275 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart K Section 98.115.

ON.20 General Stationary Combustion

ON.21 Activity Definition

For the purposes of this standard quantification method:

“General stationary combustion” has the same meaning as in the Regulation.

“Person” means a person that engages in general stationary combustion.

ON.22 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.20 – ON.26, in an emission report prepared for a calendar year in respect of general stationary combustion at a facility:

- (a) Annual greenhouse gas emissions from combustion of fuels, expressed in tonnes, reported as follows:
 - (1) Total CO₂ emissions from the combustion of fossil fuels, reported by fuel type calculated in accordance with ON.23.
 - (2) Total CO₂ emissions from the combustion of biomass, reported by fuel type calculated in accordance with ON.23.
 - (3) Total CH₄ emissions, from the combustion of all fuels reported by fuel type calculated in accordance with ON.24.
 - (4) Total N₂O emissions, from the combustion of all fuels reported by fuel type calculated in accordance with ON.24.
- (b) Annual CO₂ emissions from the use of sorbent calculated in accordance with ON.23(i).
- (c) Annual quantity of fuel consumed, reported as follows:
 - (1) For gases, expressed in Sm³.
 - (2) For liquids, expressed in kilolitres.
 - (3) For non-biomass solids, expressed in tonnes.
 - (4) For biomass-derived solid fuels, expressed in bone dry tonnes.
- (d) Annual weighted average carbon content of each fuel where carbon content is required to be measured for use in an equation.
- (e) Annual weighted average high heat value of each fuel where high heat value is required to be measured for use in an equation .
- (f) Annual amount of steam generated expressed in kilograms where equation 20-3 or 20-5 is used.
- (g) An attestation signed by the person or, where the person is not a natural person, an individual that is authorized to sign on behalf of the person confirming the total quantity of petroleum products received at the facility in

the year from each supplier that supplied petroleum to the facility during the year.

- (h) If electricity generation or cogeneration units are reporting under this Standard Quantification Method, report the cogeneration information required under ON.42(e) and ON.42(f).
- (i) Total Energy Input from the combustion of all non-biomass fuels, expressed in GJ.
- (j) For a facility that has no access to natural gas, the energy input for each non-biomass fuel express in GJ.
- (k) Total energy input from the combustion of all biomass fuels expressed in GJ.
- (l) Hot rolled steel, in tonnes.
- (m) Useful thermal energy sold in GJ.
- (n) Pulp products, in air dried tonnes
- (o) Paper products, in air dried tonnes.

Production Parameters

- (p) Beer, in hundred litres.
- (q) Coal tar feedstock processed, in tonnes.
- (r) Coated recycled boxboard in tonnes;
- (s) Fuel ethanol, in litres of absolute alcohol (excluding water, additives and denaturants).
- (t) Gypsum panels, in thousand square feet.
- (u) Industrial ethanol, in litres absolute alcohol (excluding water, additives and denaturants).
- (v) LDC Tissue Products in tonnes.
- (w) Mineral Wool in tonnes.
- (x) Polyethylene products, in tonnes.
- (y) Raw sugar processed, in tonnes.
- (z) TAD Tissue Products in tonnes.
- (aa) Used oil feed in kilolitres.

ON.23 Calculation of CO₂ Emissions

Choice of Method

- (a) The person shall calculate CO₂ emissions from the combustion of each fuel in the calendar year at an entire facility or on a unit by unit basis, as applicable, using one of the methodologies set out in (b) subject to the following rules:
 - (1) **Calculation Methodology 1**, contained in ON.23(b) may be used to calculate emissions from a facility that has:

- (i) less than 25,000 tonnes of total CO₂e emissions in respect of all Schedule 2 activities engaged in at the facility in the calendar year; or
 - (ii) 25,000 tonnes or more of total CO₂e emissions in respect of all Schedule 2 activities at the facility in the calendar year and the calculation is for emissions from the combustion of one of the following fuels:
 - (A) Natural gas with a high heat value of at least 36.3 and not greater than 40.98 MJ per cubic meter;
 - (B) Any of the fuels listed in Table 20-1a;
 - (C) Municipal solid waste combusted in a general stationary combustion unit that does not generate steam; or
 - (D) Any biomass fuel listed in Table 20-2 where the emissions associated with the combustion of that biomass are not required to be reported pursuant to any other standard quantification method for the calculation of emissions from Schedule 2 activities in the Regulation that would apply to the person for the calendar year in regards to which the report is being prepared.
- (2) Notwithstanding ON.23(a)(1)(ii), a person mentioned in ON 23(a)(1)(ii) shall not use calculation methodology 1 to calculate emissions from:
- (i) The combustion of a fuel for which the person:
 - (A) Routinely performs fuel sampling and analysis for the fuel high heat value; or
 - (B) Can obtain the results of fuel sampling and analysis for the fuel high heat value from the fuel supplier at the minimum frequency specified in ON.25(a), or at a greater frequency.
 - (ii) The combustion of natural gas in a general stationary combustion unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) that has operated for more than 1,000 hours in any of the three years prior to the calendar year that is the subject of the report.
- (3) **Calculation Methodology 2** contained in ON.23(c) may be used to calculate emissions by a person in the calendar year where the calculation is for emissions from the combustion of one of the following fuels:
- (i) Natural gas with a high heat value of at least 36.3 and not greater than 40.98 MJ per cubic meter;
 - (ii) Any of the fuels listed in Table 20-1a; and

- (iii) Any biomass fuel or municipal solid waste where the emissions associated with that combustion are not required to be reported pursuant to any other standard quantification method for the calculation of emissions from Table 2 activities that would apply to the person for the calendar year in regards to which the report is being prepared.
- (4) Subject to (5) **Calculation Methodologies 3 and 4** may be used to calculate emissions from the combustion of any type of fuel by a person in the calendar year in any general stationary combustion unit.
- (5) Notwithstanding ON.23(a)(1) through (4) **Calculation Methodology 4** shall be used to calculate all CO₂ emissions from any general stationary combustion unit for which a CEMS that includes a flow monitor subsystem and CO₂ concentration monitor is installed and:
 - (i) Is required by any applicable federal or provincial regulation; or
 - (ii) Where not required by federal or provincial regulation, is the means by which the person elects to calculate CO₂ emissions from any general stationary combustion unit.

Methods

- (b) **Calculation Methodology 1.** Use Equation 20-1 or 20-1a to calculate the annual CO₂ emissions from the combustion of each type of fuel:

$$CO_2 = Fuel \times (HHV \times EF) \times 0.001 \quad \text{Equation 20-1}$$

$$CO_2 = Fuel \times EF_c \times 0.001 \quad \text{Equation 20-1a}$$

Where:

- CO₂ = Annual CO₂ emissions from the combustion of the specific fuel type, expressed in tonnes.
- Fuel = Quantity of the fuel combusted in the calendar year, expressed in tonnes for solid fuels, standard cubic meters for gaseous fuels, and kilolitres for liquid fuels as measured in accordance with ON.25(b).
- HHV = Default high heat value of the fuel contained in Table 20-1 or Table 20-1a, expressed in GJ per tonne of solid fuel, GJ per kilolitre of liquid fuel, or GJ per cubic meter of gaseous fuel.
- EF = Fuel-specific default CO₂ emission factor contained in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, expressed in kg of CO₂ per GJ.
- EF_c = Fuel specific CO₂ default emission factor from Tables 20-2, 20-3, or 20-5, expressed in kg of CO₂ per tonne of solid fuel,

kg of CO₂ per kilolitre of liquid fuel, or kg of CO₂ per cubic meter of gaseous fuel.

0.001 = Conversion factor from kilograms to tonnes.

- (c) **Calculation Methodology 2.** Use Equation 20-2 to calculate the annual CO₂ emissions from the combustion of each type of fuel or, where the emissions are from the combustion of solid biomass fuel or municipal solid waste in general stationary combustion units that produce steam, the person may elect to use Equation 20-3 for the calculation of those emissions:

$$CO_2 = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.001 \quad \text{Equation 20-2}$$

Where:

- CO₂ = Annual CO₂ emissions from the combustion of the specific fuel type, expressed in tonnes.
- n = Number of required heat content measurements for the year as specified in ON.25.
- Fuel_p = Quantity of the fuel combusted during the measurement period “p”, expressed in tonnes for solid fuels, standard cubic meters for gaseous fuels, and kilolitres for liquid fuels as measured in accordance with ON.25(b).
- HHV_p = High heat value of the fuel for measurement period “p” calculated in accordance with ON.25(d) and (e), expressed in GJ per tonne of solid fuel, GJ per bone-dry tonne of biomass solid fuel, GJ per kilolitre of liquid fuel, or GJ per cubic meter for gaseous fuels.
- EF = Fuel-specific default CO₂ emission factor contained in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7 expressed in kg of CO₂ per GJ.
- 0.001 = Conversion factor from kilograms to tonnes.

$$CO_2 = Steam \times B \times EF \times 0.001 \quad \text{Equation 20-3}$$

Where:

- CO₂ = Annual CO₂ emissions from solid biomass fuel or municipal solid waste combustion, expressed in tonnes.
- Steam = Quantity of steam generated by biomass solid fuel or municipal solid waste combustion in the general stationary unit during the calendar year, expressed in tonnes.
- B = Ratio of the boiler’s design rated heat input capacity to its design rated steam output capacity, expressed in GJ per tonne of steam.
- EF = Default emission factor for solid biomass fuel or municipal solid waste, contained in Table 20-2 or Table 20-7 or a facility-specific emission factor determined in accordance with ON.25(a)(3)(ii), expressed in kg of CO₂ per GJ.

0.001 = Conversion factor from kilograms to tonnes.

(d) **Calculation Methodology 3.** Use Equation 20-4, 20-5, 20-6 or 20-7 as applicable to calculate the annual CO₂ emissions from the combustion of each type of fuel:

(1) For a solid fuel, use Equation 20-4:

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times 3.664 \quad \text{Equation 20-4}$$

Where:

- CO₂ = Annual CO₂ emissions from the combustion of the specific solid fuel, expressed in tonnes.
- n = Number of carbon content determinations for the year as specified in ON 25(a) and (j).
- Fuel_i = Quantity of the solid fuel combusted in measurement period “i”, expressed in tonnes as measured in accordance with ON.25(b).
- CC_i = Carbon content of the solid fuel, from the fuel analysis results for measurement period “i” calculated in accordance with ON.25(j), expressed in tonnes of C per tonne of fuel.
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

(2) For solid biomass fuels or municipal solid waste in a general stationary combustion unit that produces steam, use Equation 20-3 or 20-5:

$$CO_2 = Steam \times EF \times 0.001 \quad \text{Equation 20-5}$$

Where:

- CO₂ = Annual CO₂ emissions from the combustion of solid biomass fuel or municipal solid waste, expressed in tonnes.
- Steam = Quantity of steam generated by solid biomass fuel or municipal solid waste combustion during the calendar year, expressed in tonnes.
- EF = Measured emission factor for solid biomass fuel or municipal solid waste, expressed in kg of CO₂ per tonne of steam calculated in accordance with ON.25(a) and (j).
- 0.001 = Conversion factor from kilograms to tonnes.

(3) For liquid fuel, use Equation 20-6:

$$CO_2 = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \quad \text{Equation 20-6}$$

Where:

- CO₂ = Annual CO₂ emissions from the combustion of the specific liquid fuel, expressed in tonnes.

- n = Number of required carbon content determinations for the calendar year, as specified in ON.25(a).
- Fuel_i = Volume of the liquid fuel combusted in measurement period “i” as specified in ON.25(b), expressed in kilolitres.
- CC_i = Carbon content of the liquid fuel, from the fuel analysis results for measurement period “i” calculated in accordance with ON.25(j), expressed in tonnes of C per kilolitre of fuel.
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

(4) For a gaseous fuel, use Equation 20-7:

$$CO_2 = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \times 0.001 \quad \text{Equation 20-7}$$

Where:

- CO₂ = Annual CO₂ mass emissions from combustion of the specific gaseous fuel, expressed in tonnes.
- n = Number of carbon content determinations for the calendar year, as specified in ON.25(a).
- Fuel_i = Volume of fuel combusted in period “i”, expressed in Rm³ at reference temperature and pressure conditions as used by the facility, or expressed in kg if a mass flow meter is used as measured in accordance with ON.25(b).
- CC_i = Carbon content of the gaseous fuel, from the fuel analysis results for the period “i” calculated in accordance with ON.25(h), expressed in kg of C per Rm³ of fuel or kg of C per kg of fuel if a mass flow meter is used.
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to tonnes.

- (e) **Calculation Methodology 4.** Calculate the annual CO₂ emissions from the combustion of each type of fuel combusted in a general stationary combustion unit, by using data from CEMS calibrated and operated in accordance with ON.25(n) through (p) and the following rules:
- (1) The person shall report CO₂ emissions for the calendar year, expressed in tonnes based on the sum of hourly CO₂ emissions over the year.
 - (2) Where another standard quantification method requires the quantification of process emissions using data from CEMS in accordance with this standard quantification method, unless the other method specifies otherwise, the person shall not be required to quantify:
 - (i) Process emission separately from combustion emissions for a unit where the data from CEMS is used to quantify both process and combustion emissions; or

- (ii) Emissions from different fossil fuels separately in a unit where only fossil fuels are co-fired, though the fuel types used still need to be included in the report.
- (f) Notwithstanding ON.23(a)(4) emissions from the combustion of any fuel not listed in Tables 20-1 through 20-7; or in Table C-1 or C-2 in U.S. EPA 40 CFR Part 98, Subpart C are not required to be reported if the emissions from the combustion of the fuel does not exceed 0.5% of total facility emissions.
- (g) Notwithstanding ON.23(a) through (f) the person may use engineering methods to calculate emissions from the combustion of volatile organic compounds in thermal destruction systems. An exhaust gas stream; containing volatile organic compounds that will not sustain combustion without the addition of supplemental fuel is not considered to be combustible material. The emissions from the volatile organic compounds in such a stream are not to be reported when calculating emissions.
- (h) CO₂ emissions from combustion of mixtures of biomass or biomass fuel and fossil fuel. For the purposes of calculating biomass-related CO₂ emissions from general stationary combustion units mentioned in ON.23(a)(1) through (4) that combust a mixture of biomass fuels with another type of fuel or a fuel containing biomass the person shall use one of Calculation Methodologies 1, 2, 3 or 4 substituting relevant information from the following:
- (1) Determine the mass of biomass combusted by:
 - (i) Using company records and Calculation Methodologies 1, 2 or 3; or
 - (ii) Where the fuel is a premixed fuel that contains biomass and fossil fuels, using the best available information to determine the mass of biomass fuels and documenting the information and procedure used.
 - (2) Where calculation methodology 4 is used and the unit combusts biomass fuels that do not include waste-derived fuels, use Calculation Methodologies 1, 2, or 3 to calculate the annual CO₂ mass emissions from the combustion of fossil fuels and then calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO₂ emissions determined using Calculation Methodology 4.
 - (3) Where the person combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented, or a biomass fuel for which a CO₂ emission factor is not provided in Table 20-2, the person shall use ASTM D6866 in accordance with ON.25(m).
 - (4) Notwithstanding ON.25(h)(1) through (3) a person is not required to calculate biomass-related CO₂ emissions from the combustion of fuels that contain less than 5 per cent biomass by weight or waste-derived fuels that

are less than 30 per cent by weight of total fuels combusted in calendar year.

- (5) Where a person uses Calculation Methodology 1 to calculate CO₂ emissions from solid biomass fuel, the person may elect to use Equation 20-8 to calculate the biomass-related emissions from the combustion of that fuel:

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{(HHV)_{bio} (Eff)_{bio}} \quad \text{Equation 20-8}$$

Where:

- (Fuel)_p = Quantity of biomass consumed during the measurement period “p”, expressed in tonnes per year or tonnes per month, as applicable.
- H = Average enthalpy of the boiler steam for the measurement period, expressed in GJ per tonne.
- S = Quantity of boiler steam produced for measurement period “p”, expressed in tonnes/month or tonnes/year, as applicable.
- (HI)_{nb} = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and HHV values contained in ON.20 or measured HHV values, expressed in GJ per month or GJ per year, as applicable.
- (HHV)_{bio} = HHV values contained in Table 20-1 or measured HHV of the biomass fuel, expressed in GJ per tonne.
- (Eff)_{bio} = Efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

(i) Calculation of CO₂ from the use of sorbent.

- (1) Where a person operates a fluidized bed boiler that is equipped with a wet flue gas desulphurization system, or uses other acid gas emission controls with sorbent injection, the person shall calculate CO₂ emissions using:

- (i) Data from CEMS; or
(ii) Where CEMS are not required to be used, using Equation 20-9 :

$$CO_2 = S * R * \left(\frac{MW_{CO_2}}{MW_s} \right)$$

Equation 20-9

Where:

CO_2	=	Annual CO_2 emissions from the use of sorbent, expressed in tonnes.
S	=	Quantity of limestone or other sorbent used in the calendar year, from company records, expressed in tonnes.
R	=	The calcium-to-sulphur stoichiometric ratio which has a value of 1.00, or is determined based on actual sorbent used.
MW_{CO_2}	=	Molecular weight of carbon dioxide.
MW_S	=	Molecular weight of sorbent.

- (j) The annual CO_2 emissions for all units shall be the sum of the CO_2 emissions for each type of fuel from the calculations under paragraphs (b), (c), (d), (e) and (i) of ON.23.
- (k) Notwithstanding ON.23(a) through (f) the person is not required to calculate emissions from the combustion of process gas that is transferred from another capped participant's facility where the amount of process gas that is transferred is included in equations 150-3 or 150-8 of ON.152 in a report required to be submitted by the other capped participant under the Regulation.
- (l) Where a quantity of natural gas is distributed by a natural gas distributor to a person's capped facility and the following criteria apply:
- (1) The natural gas is recorded by the natural gas billing meter used for billing the person at the capped facility; and
 - (2) Some or all of the natural gas that is recorded by the natural gas billing meter for the capped facility is used by an uncapped facility.
- The person is required to include the quantity of natural gas used by the uncapped facility in the value of: "fuel" in equations 20-1 and 20-1a, "fuel_p" in equation 20-2, and "fuel_i" in equation 20-7.
- (m) Notwithstanding ON.23(a), if a person that is required to include a quantity of natural gas used by an uncapped facility pursuant to paragraph (l) is quantifying emissions using Methodology 4, the person shall calculate the emissions from the combustion of the fuel used by the uncapped facility using Methodology 2 or 3 as applicable.
- (n) The person that is required to quantify and, where applicable, report the GHG emissions from the uncapped facility mentioned in paragraph (l) shall not include the quantity of natural gas received from the capped facility mentioned in paragraph (l) in the value of: "fuel" in equations 20-1 and 20-1a, "fuel_p" in equation 20-2, and "fuel_i" in equation 20-7.
- (o) If a person referenced in paragraph (n) is quantifying emissions using Methodology 4, the person shall subtract emissions from the use of the fuel provided to them from the emissions calculated using Methodology 4. The

emissions from the subtracted fuel shall be calculated using Methodology 2 or 3.

- (p) A capped participant listed in Table 20-8 is required to include the quantity of natural gas that is distributed to the facility with GHG ID number 1144 located at 1741 River Road, Sarnia, and for which the capped participant pays a natural gas distributor in the year in the value of the: “fuel” in equations 20-1 and 20-1a, “fuel_p” in equation 20-2 and “fuel_i” in equation 20-7.
- (q) If a person is required to calculate emissions from the facility with GHG ID 1144 located at 1741 River Road, Sarnia, the person shall calculate the emissions in accordance with the applicable method in ON.23; but, shall not include the quantity of the natural gas that a capped participant listed in Table 20-8 pays a natural gas distributor for in the year, in the value of “fuel” in equations 20-1 and 20-1a, “fuel_p” in equation 20-2 and “fuel_i” in equation 20-7.
- (r) If a person that is required to calculate emissions from the facility with GHG ID 1144 located at 1741 River Road, Sarnia, is quantifying emissions using Methodology 4, the person shall subtract emissions from the use of the natural gas; that a capped participant listed in Table 20-8 pays a natural gas distributor for in the year; from the emissions calculated using Methodology 4. The emissions from the subtracted natural gas shall be calculated using Methodology 2 or 3.

ON.24 Calculation of CH₄ and N₂O Emissions

Choice of Method

- (a) The person shall calculate CH₄ and N₂O emissions from the combustion of any fuel listed in Tables 20-2, 20-3, 20-4 and 20-6 in the calendar year using one or more of the following calculation methodologies as applicable:
 - (1) **Calculation Methodology 5** contained in ON.24(c) may only be used to calculate emissions from a facility that combusts:
 - (i) Natural gas with a high heat value of at least 36.3 and not greater than 40.98 MJ per cubic meter;
 - (ii) Any fuel listed in Table 20-1a; or
 - (iii) Any biomass fuel listed in Table 20-2.
 - (2) **Calculation Methodology 6** contained in ON.24(d) may be used to calculate emissions from any general stationary combustion unit that combusts any type of fuel.
 - (3) **Calculation Methodology 7** contained in ON.24(e) may only be used to calculate emissions from a general stationary combustion unit that calculates CO₂ emissions using Equations 20-3 and 20-5.
 - (4) Notwithstanding ON.24(a)(1) through (3) Calculation Methodology 8 ON.24(f) shall be used to calculate all CH₄ and N₂O emissions from any

general stationary combustion unit for which Calculation Methodology 4 is used and heat input is monitored on a year round basis.

- (5) Notwithstanding the above, a person at a facility that has total reported CO₂e emissions below 25,000 tonnes per year from all Table 2 activities at the facility may elect to use any of the above methods to calculate emission from the combustion of any fuel listed in Tables 20-2, 20-3, 20-4 and 20-6.
- (b) The person may elect to use engineering estimates to calculate the annual CH₄ and N₂O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6.

Methods

- (c) **Calculation Methodology 5.** Use Equations 20-10 or 20-11 as applicable to calculate the annual CH₄ and N₂O emissions from the combustion of each fuel.

- (1) For non-coal fuel, use Equation 20-10:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^n Fuel_i \times HHV \times EF \times 0.000001 \quad \text{Equation 20-10}$$

- (2) For coal, use Equation 20-11:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^n Fuel_i \times EF_c \times 0.001 \quad \text{Equation 20-11}$$

Where:

- E = Annual CH₄ or N₂O emissions from a specific fuel type, expressed in tonnes.
- Fuel_i = Quantity of the fuel combusted during measurement period “i”, expressed in tonnes for solid fuels, standard cubic meters for gaseous fuels, and kilolitres for liquid fuels.
- HHV = Default high heat value for fuel type “i” contained in Table 20-1 or 20-1a expressed in GJ per tonne of solid fuel, GJ per kilolitre of liquid fuel, or GJ per cubic meter of gaseous fuel.
- EF = Default CH₄ or N₂O emission factor for fuel type contained in Tables 20-2 or 20-4, as applicable, expressed in grams CH₄ or N₂O per GJ or an equipment-specific emission factor contained in U.S. EPA AP42 as appropriate.
- EF_c = Default CH₄ or N₂O emission factor for each coal type contained in Table 20-6, expressed in grams CH₄ or N₂O per kg of coal or an equipment-specific emission factor contained in U.S. EPA AP42 as appropriate.
- 0.000001 = Conversion factor from grams to tonnes.

0.001 = Conversion factor from g/kg to tonnes/tonne.

(d) **Calculation Methodology 6.** Use Equation 20-12 or 20-13 as applicable to calculate the annual CH₄ and N₂O emissions from the combustion of each fuel.

(1) For non-coal fuel, use Equation 20-12:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^n Fuel_i \times HHV_i \times EF \times 0.000001 \quad \text{Equation 20-12}$$

(2) For coal, use Equation 20-11:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^n Fuel_i \times EF_{c,i} \times 0.000001 \quad \text{Equation 20-13}$$

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from a specific fuel type, expressed in tonnes.

Fuel_i = Quantity of fuel combusted during measurement period “i”, expressed in tonnes for solid fuels, standard cubic meters for gaseous fuels, and kilolitres for liquid fuels.

HHV_i = High heat value measured directly or provided by the fuel supplier for the specified fuel type, expressed as GJ per tonne of solid fuel, GJ per kilolitre of liquid fuel, or GJ per cubic meter of gaseous fuel in accordance with ON.25(d) and (e).

EF_i = Default CH₄ or N₂O emission factor for each fuel type contained in Table 20-2 or 20-4, as applicable, expressed in grams CH₄ or N₂O per GJ or an equipment-specific emission factor contained in U.S. EPA AP42 as appropriate.

EF_c = CH₄ or N₂O emission factor for each coal type either measured directly or provided by the fuel supplier, expressed in grams CH₄ or N₂O per tonne of coal.

0.000001 = Conversion factor from grams to tonnes.

(e) **Calculation Methodology 7.** Use Equation 20-15 to calculate the annual CH₄ and N₂O emissions from the combustion of biomass fuel or municipal solid waste.

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.000001 \quad \text{Equation 20-14}$$

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of biomass fuel or municipal solid waste, expressed in tonnes.

Steam	=	Quantity of steam generated by biomass or municipal solid waste combustion during the calendar year, expressed in tonnes.
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output, expressed in GJ per tonne of steam.
EF	=	Default emission factor for CH ₄ or N ₂ O, contained in Tables 20-2, 20-4, 20-6 or 20-7, as applicable, expressed in grams per GJ.
0.000001	=	Conversion factor from grams to tonnes.

(f) **Calculation Methodology 8.** Use Equation 20-15.

$$CH_4 \text{ or } N_2O = 0.000001 * HI_A * EF \quad \text{Equation 20-15}$$

Where:

CH ₄ or N ₂ O	=	Annual CH ₄ or N ₂ O emissions from the combustion of a specific type of fuel, expressed in tonnes.
HI _A	=	Cumulative annual heat input from each type of fuel, expressed in GJ in accordance with ON.25(g).
EF	=	Default fuel-specific emission factor for CH ₄ or N ₂ O, contained in Tables 20-2, 20-4 or 20-6, as applicable, expressed in grams per GJ, grams per kilogram of solid fuel, grams of kiloliter for liquid fuel and grams per cubic meter of gaseous fuel.
0.000001	=	Conversion factor from grams to tonnes.

- (g) Where Calculation Methodologies 5 to 8 require the use of an emissions factor the person may elect to use facility-specific emission factors derived from source tests conducted annually to calculate CH₄ or N₂O emissions using Equation 20-11.
- (h) When multiple fuels are combusted during the calendar year, sum the fuel-specific results from the Equations in ON.24 to obtain the total annual CH₄ and N₂O emissions, expressed in tonnes.
- (i) Notwithstanding ON.24(a) through (f) the person is not required to calculate emissions from the combustion of process gas that is transferred from another capped participant's facility where the amount of process gas that is transferred is included in equations 150-3 or 150-8 of ON.152 in a report required to be submitted by the other capped participant under the Regulation.
- (j) Where a quantity of natural gas is distributed by a natural gas distributor to a person's capped facility and the following criteria apply:

- (1) The natural gas is recorded by the natural gas billing meter used for billing the person at the capped facility; and
- (2) Some or all of the natural gas that is recorded by the natural gas billing meter for the capped facility is used by an uncapped facility.

The person is required to include the quantity of natural gas used by the uncapped facility in the value of “fuel_i” in equations 20-10, and 20-12.

- (k) Notwithstanding ON.24(a), if a person that is required to include a quantity of natural gas used by an uncapped facility pursuant to paragraph (j) is quantifying emissions using Methodology 8, the person shall adjust the value of Hl_A to include the heat input from the natural gas used by the uncapped facility.
- (l) The person that is required to quantify and, where applicable, report GHG emissions from the uncapped facility mentioned in paragraph (j) shall not include the quantity of natural gas received from the capped facility mentioned in paragraph (j) in the value of “fuel_i” in equations 20-10, and 20-12.
- (m) If a person referenced in paragraph (l) is quantifying emissions using Methodology 8, the person shall subtract emissions from the use of the fuel provided to them from the emissions calculated using Methodology 8. The emissions from the subtracted fuel shall be calculated using Methodology 5 or 6.
- (n) A capped participant listed in Table 20-8 is required to include the quantity of natural gas that is distributed to the facility with GHG ID 1144 located at 1741 River Road, Sarnia and for which the capped participant pays a natural gas distributor for in the year in the value of “fuel_i” in equations 20-10, and 20-12.
- (o) If a person is required to calculate emissions from the facility with GHG ID 1144 at 1741 River Road, Sarnia, the person shall calculate the emissions in accordance with the appropriate method in ON.24; but, shall not include the quantity of the natural gas, that a capped participant listed in the Table 20-8 pays the natural gas distributor for in the year in the value of “fuel_i” in equations 20-10, and 20-12.
- (p) If a person that is required to calculate emissions from the facility with GHG ID 1144 at 1741 River Road, Sarnia, is quantifying emissions using Methodology 8, the person shall subtract emissions from the use of the natural gas; that a capped participant listed in Table 20-8 pays a natural gas distributor for in the year; from the emissions calculated using Methodology 8.

The emissions from the subtracted natural gas shall be calculated using Methodology 5 or 6.

ON.25 Sampling, Analysis, and Measurement Requirements

Fuel Sampling Frequency Requirements

- (a) The person required to obtain fuel samples pursuant to this standard quantification method shall do so by conducting fuel sampling or obtaining fuel sampling results from the fuel supplier in accordance with the following rules:
- (1) Fuel samples shall be taken at a location in the fuel handling system that provides a representative sample of the fuel combusted.
 - (2) Fuel samples shall be obtained and analysis performed at the following minimum frequencies:
 - (i) Once for each shipment or delivery of coal.
 - (ii) Once for each new fuel shipment or delivery, or quarterly for each of the fuels listed in Table 20-1a.
 - (iii) Semiannually for natural gas.
 - (iv) Quarterly for liquid fuels other than fuels listed in Table 20-1a.
 - (v) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
 - (vi) Daily for gaseous fuels other than natural gas, gases derived from biomass, and biogas in order to determine the carbon content and molecular weight of the fuel if the necessary equipment is in place to make these measurements.
 - (vii) Weekly for gaseous fuels other than natural gas, gases derived from biomass, and biogas, where the necessary equipment is not in place to make daily measurements.
 - (viii) Monthly composite samples of solid fuels other than coal and waste-derived fuels shall be taken in accordance with the following:
 - (A) The sample shall be a composite sample of weekly samples of equal mass taken during the month.
 - (B) Sampling shall be done at a location after all fuel treatment operations but before fuel combustion.
 - (C) Samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
 - (D) Sub-samples shall be collected at a day and time when the fuel consumption rate is representative and unbiased.

- (E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
 - (F) One in every twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples.
- (3) Where the fuel being sampled is a biomass or waste-derived fuel, the following sampling frequencies may apply in lieu of those contained in ON.25(a)(2)(iv), (v) and (viii):
- (i) If CO₂ emissions are calculated using Equation 20-2 or 20-4, the facility-specific high heat value or carbon content is determined annually.
 - (ii) If CO₂ emissions from the combustion of biomass fuels or municipal solid waste are calculated using Equation 20-5, the person shall:
 - (A) Adjust the emission factor no less frequently than every third year, through a stack test measurement of CO₂; and
 - (B) Use the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

Fuel Consumption Monitoring Requirements.

- (b) The person required to monitor fuel consumption pursuant to this standard quantification method shall do so by monitoring in accordance with the following rules:
- (1) Fuel consumption shall be determined using:
 - (i) Direct measurement; or
 - (ii) Measured stock changes in fuel calculated in accordance with Equation 20-16 expressed in MJ, litres, million standard cubic meters, tonnes or bone dry tonnes as appropriate.

$$\text{Fuel Consumption in the Report Year} = \text{Total Fuel Purchases} - \text{Total Fuel Sales} + \text{Amount Stored at Beginning of Year} - \text{Amount Stored at Year End}$$

Equation 20-16

- (2) For the purposes of calculating total fuel purchases of natural gas, the calculation can be based on the recorded fuel purchases or sales invoices in the calendar year for which the report is being prepared without accounting for fuel recorded in those recorded purchases or invoices that may be used in the previous or subsequent year.

- (3) Where fuel consumption is measured in MJ, the person shall convert to mass or volume using heat content values that are either provided by the supplier, measured by the facility, or contained in Table 20-1.
- (4) For fuel oil, tank drop measurements may also be used to calculate fuel consumption.
- (5) A person required to determine quantities of liquid fuel pursuant to this method may elect to use a volumetric flow meter or a fuel flow meter that measures mass flow rates and is used in accordance with the following:
 - (i) Fuel density shall be used to convert the readings to volumetric flow rates; and
 - (ii) Density shall be measured at the same frequency as the carbon content, using one of the following methods:
 - (A) Any applicable method listed in the Technical Reference Document section of this Guideline;
 - (B) The most appropriate method published by a consensus-based standards organization; or
 - (C) Where no appropriate method is published by a consensus-based standards organization, using industry standard methods, noting where such methods are used and what methods are used.
- (6) Notwithstanding ON.25(b)(5)(ii), a person that uses Calculation Methodologies 1 or 2 may elect to use the following default density values for fuel oil:

Fuel Oil Default Density Values

Fuel Oil	No.1 Oil	No.2 Oil	No.6 Oil
Default Density, kg/litre	0.81	0.86	0.97

(c) Calibration requirements

- (1) A person required to determine quantities of fuel in accordance with this method shall calibrate all fuel oil and gas flow meters except for meters on the natural gas delivery system (including gas billing meters) prior to the first calendar year for which GHG emissions are required to be reported pursuant to this method using calibration or verification procedures specified by the flow meter manufacturer or Measurement Canada.
- (2) A person required to determine quantities of fuel in accordance with this method shall recalibrate all fuel flow meters:
 - (i) At least once every three years;
 - (ii) Upon replacement of a previously calibrated meter; or

- (iii) At the minimum frequency specified by the manufacturer or under the laws and regulations of Measurement Canada.
- (3) A person required to determine quantities of fuel in accordance with this method shall calibrate orifice, nozzle, and venturi flow meters using in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters.

Fuel Heat Content Monitoring Requirements.

- (d) A person required to monitor heat content of gaseous fuels in accordance with this method shall do so in accordance with the following rules:
 - (1) Using any applicable analytical methods listed in the Technical Reference Document section of this Guideline;
 - (2) Using the most appropriate method published by a consensus-based standards organization; or
 - (3) Where no appropriate method is published by a consensus-based standards organization, using industry standard methods, noting where such methods are used and what methods are used.
 - (4) For natural gas, using methods and requirements in accordance with the requirements under the laws and regulation of Measurement Canada for electricity and gas.
 - (5) Using on-line instrumentation that determines heating value accurate to within ± 5.0 per cent and, where such instrumentation provides only low heat value, the person shall convert the value to high heat value using Equation 20-17 in accordance with the following:
 - (i) When the heating value of natural gas is being measured the value of CF shall be 1.11.
 - (ii) Where the heating value of refinery fuel gas or mixtures of refinery fuel gas is being measured, the CF shall be determined as a fuel-specific weekly average CF using the following:
 - (A) Concurrent LHV and HHV measurements determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or
 - (B) The HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

$$HHV = LHV \times CF \qquad \text{Equation 20-17}$$

Where:

- HHV = Fuel or fuel mixture high heat value, expressed in MJ per Sm^3 .
- LHV = Fuel or fuel mixture low heat value, expressed in MJ per Sm^3 .
- CF = Conversion factor.

- (e) The person shall conduct fuel heat content monitoring of all solid and liquid fuel, including biomass and waste derived fuels, in accordance with the following:
- (1) Using any applicable analytical methods listed in the Technical Reference Document section of this Guideline;
 - (2) Using the most appropriate method published by a consensus-based standards organization; or
 - (3) Where no appropriate method is published by a consensus-based standards organization, using industry standard methods, noting where such methods are used and what methods are used.
- (f) The person required to use Equation 20-15 shall derive the cumulative annual heat input (H_{IA}): estimated from the best available information such as fuel feed rate measurements, fuel heating values, engineering analysis, or information used for accounting purposes.
- (g) Use Equation 20-18 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO₂ emissions.

$$(HHV)_{annual} = \frac{\sum_{p=1}^n (HHV)_p * (Fuel)_p}{\sum_{p=1}^n (Fuel)_p} \quad \text{Equation 20-18}$$

Where:

- (HHV)_{annual} = Weighted annual average high heat value of the fuel, expressed in GJ per tonne of solid fuel, GJ per kilolitre of liquid fuel, or GJ per cubic meter of gaseous fuel.
- (HHV)_p = High heat value of the fuel, for measurement period “p”, expressed in GJ per tonne of solid fuel, GJ per kilolitre of liquid fuel, or GJ per cubic meter of gaseous fuel.
- (Fuel)_p = Quantity of the fuel combusted during measurement period “p”, expressed in tonnes for solid fuels, standard cubic meters for gaseous fuels, and kilolitres for liquid fuels.
- n = Number of measurement periods in the calendar year that fuel is combusted in the unit.

Fuel Carbon Content Monitoring Requirements.

- (h) The person required to determine fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall use the results of fuel sampling and analysis received from the fuel supplier or results determined by the person using the following:

- (1) Any applicable analytical methods listed in the Technical Reference Document section of this Guideline;
 - (2) The most appropriate method published by a consensus-based standards organization;
 - (3) Where no appropriate method is published by a consensus-based standards organization, using industry standard methods, noting where such methods are used and what methods are used; or
 - (4) For natural gas, using methods and requirements in accordance with the requirements under the laws and regulation of Measurement Canada for electricity and gas.
- (i) The person required to determine the carbon content of solid or liquid fuel including biomass and waste-derived fuels shall use the results of fuel sampling and analysis received from the fuel supplier or results determined by the person using the following.
- (1) Any applicable analytical methods listed in the Technical Reference Document section of this Guideline;
 - (2) The most appropriate method published by a consensus-based standards organization; or
 - (3) Where no appropriate method is published by a consensus-based standards organization, using industry standard methods, noting where such methods are used and what methods are used.
- (j) If on-line instrumentation is used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight shall determine fuel carbon content accurate to ± 5 per cent.
- (k) The person required to calculate the weighted annual average carbon content of fuel pursuant to this method shall do so using Equation 20-19 if measured carbon content is used to calculate CO₂ emissions.

$$(CC)_{annual} = \frac{\sum_{p=1}^n (CC)_p * (Fuel)_p}{\sum_{p=1}^n (Fuel)_p} \quad \text{Equation 20-19}$$

Where:

(CC)_{annual} = Weighted annual average carbon content of the fuel, expressed in tonnes of C per tonne of solid fuel, tonnes of C per kilolitre of liquid fuel, or kg of C per kg of gaseous fuel.

- (CC)_p = Carbon content of the fuel, for measurement period “p” (expressed in tonnes of C per tonne of solid fuel, tonnes of C per kilolitre of liquid fuel, or kg of C per kg of gaseous fuel.
- (Fuel)_p = Quantity of the fuel combusted during measurement period “p”, expressed in tonnes for solid fuels, standard cubic meters for gaseous fuels, and kilolitres for liquid fuels.
- n = Number of measurement periods in the calendar year that fuel is combusted in the unit.
- (l) The person required to use ASTM D6866 under ON.23(h)(3) shall use the following to determine the biomass carbon fraction of the fuel or fuel mixture.
- (1) Conduct ASTM D6866 analysis on a representative fuel sample at least once every three months.
 - (2) Conduct ASTM D6866 analysis on a representative exhaust gas sample at least once every three months. The exhaust gas samples shall be collected over at least 24 consecutive hours following the standard practice specified by ASTM D7459.
 - (3) If municipal solid waste is combusted, the ASTM D6866 analysis shall be performed on the exhaust gas stream.
 - (4) If there is a common fuel source to multiple units at the facility, the person may elect to conduct ASTM D6866 testing for only one of the units sharing the common fuel source.

Continuous Emissions Monitors and Source Testing

- (m) The person that uses Calculation Methodology 4 under ON.23(e) shall select and operate the CEMS in accordance with EPS 1/PG/7.
- (n) Notwithstanding the requirement in EPS 1/PG/7 to use a CO₂ concentration monitor, a person using Calculation Methodology 4 may use an oxygen (O₂) concentration monitor in lieu of a CO₂ concentration monitor in a CEMS installed before January 1, 2017, to determine hourly CO₂ concentrations, if:
- (1) The effluent gas stream monitored by the CEMS consists solely of combustion products ;
 - (2) Only one or more of the following fuels are combusted in the unit: coal, biomass, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue;
 - (3) The unit does not combust waste derived fuels other than wood bark or wood residue; and
 - (4) Where the CEMS is used to monitor emissions from the combustion of biomass fuel other than wood bark or wood residue, annual source testing demonstrates that the use of O₂ concentrations to calculate CO₂

concentrations meets all the requirements of EPS 1/PG/7 including the Relative Accuracy Test Audit (RATA).

- (o) The person required to conduct source or performance testing shall do so as follows:
- (1) Where a facility-specific emission factor for CH₄ and N₂O is used it shall be updated annually.
 - (2) Where a facility-specific emission factor determined in accordance with Equation 20-3 or 20-5 is used, the factor shall be updated at least every third year.
- (p) **Fuel Analytical Data Capture.** Where a person is required to collect fuel analytical data, the data capture rate shall be 80 per cent or more. The person shall measure the quantity of products identified in ON.22(k). Equipment used to measure the production quantity shall be:
- (1) calibrated according to the manufacturer's instructions and
 - (2) maintained an accuracy of plus or minus 5%.
- (q) The person shall measure the production parameter quantities. The equipment used to measure the production parameter quantities shall:
- (1) be calibrated according to the manufacturer's instructions; or, where not available calibrate according to practices used for accounting purposes; and
 - (2) be maintained to achieve an accuracy of plus or minus 5%.

ON.26 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.25, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.23 (a), (b) and (c) and ON.24 (a), (b) and (c) for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (1) When the missing data concerns high heat value, carbon content, molecular mass, CO₂ concentration, water content or any other data sampled, the person shall:
 - (i) Determine the sampling or measurement rate using Equation 20-20:

$$R = Q_{SAct}/Q_{SRequired} \quad \text{Equation 20-20}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{S Required}$ = Quantity of samples or measurements required under ON.25

- (ii) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period.
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the calendar year for which the calculation is made.
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years.

(2) When the missing data concerns stack gas flow rate, fuel consumption or the quantity of sorbent used, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

(c) A person who uses CEMS shall determine the replacement data using the procedure in EPS 1/PG/7 or the following method:

(1) When the missing data is data measured by the CEMS;

- (i) Determine the sampling or measurement rate using Equation 20-21:

$$R = H_{S Act}/H_{S Required} \quad \text{Equation 20-21}$$

Where:

R = Sampling or measurement rate, that was used, expressed as a percentage

$H_{S Act}$ = Quantity of actual samples or measurements obtained by the person

$H_{S Required}$ = Quantity of samples or measurements required under ON.25

- (ii) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data

period, the person shall use the first available data from after the missing data period.

- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the calendar year for which the calculation is made.
- (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years.

Table 20-1: Default High Heat Value by Fuel Type

Liquid Fuels	High Heat Value (GJ/kl)
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane ¹	(see Table 20-2)
Ethane	(see Table 20-2)
Butane	(see Table 20-2)
Lubricants	39.16
Motor Gasoline - Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (#5 & 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke - Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Ethanol (100%)	21.04
Biodiesel (100%)	32.06
Rendered Animal Fat	31.05
Vegetable Oil	30.05
Solid Fuels	High Heat Value (GJ/tonne)
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste (dry, 0% moisture)	19.2
Spent Pulping Liquor	14
Municipal Solid Waste	11.57
Tires	31.18
Agricultural byproducts	8.6
Solid byproducts	26.93
Gaseous Fuels	High Heat Value (GJ/m3)
Natural Gas	0.038
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (captured methane)	0.0359
Other Biogas (captured methane)	0.0359

¹The default high heat value for propane is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 20-1a should be used instead.

Table 20-1a
Default High Heating Value and Emission Factor (Commonly Used Fuels)

Fuel Type	Default High Heat Value	Default CO ₂ Emission Factor
Petroleum Products	GJ/kilolitre	kg CO ₂ /GJ
Distillate Fuel Oil No. 1	38.78	69.16
Distillate Fuel Oil No. 2	38.50	70.18
Distillate Fuel Oil No. 4	40.73	71.10
Kerosene	37.68	71.18
Propane or Liquefied petroleum gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs) ¹	25.48	59.59
Propylene	25.39	62.46
Ethane	18.91	56.49
Ethylene	27.90	56.49
Isobutane	27.61	61.55
Isobutylene	28.73	64.16
Butane	28.80	60.83
Butylene	28.73	61.39
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40
Aviation Gasoline	33.52	65.49
Kerosene-Type Jet Fuel	37.66	71.22

¹The default factors for "propane" are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

Table 20-2: Default Emission Factors by Fuel Type

Fuel Type	CO ₂ Emission Factor	CO ₂ Emission Factor	CH ₄ Emission Factor	CH ₄ Emission Factor	N ₂ O Emission Factor	N ₂ O Emission Factor
	(kg /kL)	(kg /GJ)	(g/L)	(g/GJ)	(g/L)	(g/GJ)
Liquid Fuels						
Aviation Gasoline	2342	see Table 20-1a	2.2	65.63	0.23	6.862
Diesel	2663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2534	see Table 20-1a	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2534	see Table 20-1a	0.006	0.159	0.031	0.823
- Industrial	2534	see Table 20-1a	0.006	0.159	0.031	0.823
- Producer Consumption	2534	see Table 20-1a	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2534	see Table 20-1a	0.026	0.69	0.031	0.823
Propane (or liquefied petroleum gases)						

Fuel Type	CO ₂ Emission Factor	CO ₂ Emission Factor	CH ₄ Emission Factor	CH ₄ Emission Factor	N ₂ O Emission Factor	N ₂ O Emission Factor
- Residential	1510	see Table 20-1a	0.027	1.067	0.108	4.267
- All other uses	1510	See Table 20-1a	0.024	0.948	0.108	4.267
Ethane	976	See Table 20-1a	N/A	N/A	N/A	N/A
Butane	1730	See Table 20-1a	0.024	0.844	0.108	3.797
Lubricants	1410	36.01	N/A	N/A	N/A	N/A
Motor Gasoline – Off-Road	2289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil (Distillate Fuel Oil)						
- Electric Utilities	2725	70.23	0.18	4.639	0.031	0.799
- Industrial	2725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3124	NA	0.034	0.800	0.064	1.506
- Industrial	3124	NA	0.12	2.824	0.064	1.506
- Producer Consumption	3158	NA	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3124	NA	0.057	1.341	0.064	1.820
Naphtha	625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	500	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3494	86.12	0.12	2.958	0.0231	0.569
Biomass Fuels	(kg/tonne)	(kg /GJ)	(g/kg)	(g/GJ)	(g/kg)	(g/GJ)
Landfill Gas	2989	54.6	0.6	1.0	0.06	0.1
Wood Waste (dry, 0% moisture)	1,800 ¹	93.7 ¹	0.576	30 ²	0.077	4 ²
Spent Pulping Liquor (at 0% moisture)	1,239	91.8 ¹	0.039	2.9 ³	0.026	1.9 ³
Agricultural byproducts	NA	112	NA	NA	NA	NA
Solid byproducts	NA	100	NA	NA	NA	NA
Biogas (capture methane)	NA	49.4	NA	NA	NA	NA
Ethanol (100%)	NA	64.9	NA	NA	NA	NA
Biodiesel (100%)	NA	70	NA	NA	NA	NA
Rendered Animal Fat	NA	67.4	NA	NA	NA	NA
Vegetable Oil	NA	77.3	NA	NA	NA	NA

Fuel Type	CO ₂ Emission Factor	CO ₂ Emission Factor	CH ₄ Emission Factor	CH ₄ Emission Factor	N ₂ O Emission Factor	N ₂ O Emission Factor
Other Solid Fuels						
Coal Coke	2480	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	(kg /m³)	(kg /GJ)	(g/m3)	(g/GJ)	(g/m3)	(g/GJ)
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas – Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas – Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2009, unless otherwise stated

¹A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Government Ministry of Environment.

²US EPA (2009). U.S. Environmental Protection Agency. Mandatory reporting of greenhouse gases, final rule. Washington, DC, 2009.

³IPCC (2006). Intergovernmental Panel on Climate Change. 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Japan, 2006.

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

Province	Marketable Gas (kg/m ³)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m ³)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.863	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH ₄ (g/m ³)	CH ₄ (g/GJ)	N ₂ O (g/m ³)	N ₂ O (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2009

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg CO ₂ /tonne coal)	Emission Factor (kg CO ₂ /GJ)
Quebec		
- Canadian Bituminous	2250	85.5
- U.S. Bituminous	2340	88.9
- Anthracite	2390	86.3
Ontario		
- Canadian Bituminous	2250	85.5
- U.S. Bituminous	2430	81.5
- Sub-bituminous	1730	90.3
- Lignite	1480	98.7
- Anthracite	2390	86.3
Manitoba		
- Canadian Bituminous	2250	85.5
- U.S. Bituminous	2430	81.5
- Sub-bituminous	1730	90.3
- Lignite	1420	94.7
- Anthracite	2390	86.3
British Columbia		
- Canadian Bituminous	2070	78.6
- U.S. Bituminous	2430	81.5
- Sub-bituminous	1770	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2009

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH ₄ Emission Factor (g/kg)	N ₂ O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2009

Table 20-7: Other Emission Factors

	CO ₂ Emission Factor (kg/GJ)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/GJ)
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO₂ emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

Table 20-8: List of Facilities

GHG ID	Street Address (Physical Address)
1100	785 Petrolia Line, Corunna
1101	510 Moore Line, Mooretown
1102	285 Albert Street, Corunna
1132	872 Tashmoo Avenue, Sarnia
1133	1900 River Road, Sarnia
1191	1265 Vidal Street, Sarnia

ON.140 Glass Production

ON.141 Activity Definition

For the purposes of this standard quantification method:

“Glass production” has the same meaning as in the Regulation.

“Person” means a person that engages in glass production.

ON.142 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.140 – ON.145, in an emission report prepared for a calendar year in respect of glass production at a facility:

- (a) Total CO₂ process emissions from all glass melting furnaces (tonnes).
- (b) Total CO₂, CH₄ and N₂O combustion emissions from all glass melting furnaces (tonnes). The person shall calculate and report these emissions by following the requirements of ON.20.
- (c) If a CEMS is not used to determine CO₂ emissions from glass melting furnaces, and process CO₂ emissions are calculated according to the procedures specified in ON.143(b), report the following information:
 - (1) Annual quantity of each carbonate-based raw material charged for all furnaces combined (tonnes).
 - (2) Total number of glass melting furnaces.

Production Parameters

- (d) Annual quantity of glass bottles, glass jars or other glass products produced from all furnaces combined (tonnes).

ON.143 Calculation of CO₂ Emissions

The person shall calculate the annual process CO₂ emissions from each glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

- (a) For each glass melting furnace that meets the conditions specified in ON.23, the person shall calculate the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to Calculation Methodology 4 specified in ON.23 and all associated requirements in ON.20.
- (b) For each glass melting furnace that is not subject to the requirements in paragraph (a) of this section, use either the procedure in paragraph (b)(1) of this section or the procedure in paragraphs (b)(2) through (b)(7) of this section, except as specified in paragraph (c) of this section.

- (1) Calculate the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to Calculation Methodology 4 specified in ON.23.
- (2) Calculate the process and combustion CO₂ emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(iv) of this section.
 - (i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.
 - (ii) Determine the quantity of each carbonate-based raw material charged to the furnace.
 - (iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table 140-1 to this method.
 - (iv) Use Equation 140-1 of this section to calculate process mass emissions of CO₂ for each furnace:

$$E_{CO_2} = \sum_{i=1}^n (M_i \times MF_i \times EF_i \times F_i) \quad \text{Equation 140-1}$$

Where:

- E_{CO_2} = Process emissions of CO₂ from the furnace (tonnes).
- n = Number of carbonate-based raw materials charged to furnace.
- MF_i = Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (weight fraction).
- M_i = Annual amount of carbonate-based raw material i charged to furnace (tonnes).
- EF_i = Emission factor for carbonate-based mineral i (tonnes CO₂ per tonne carbonate-based mineral as shown in Table 140-1).
- F_i = Fraction of calcination achieved for carbonate-based mineral i , 1.0 for completed calcination(weight fraction).

- (v) The person shall calculate and report the total process CO₂ emissions from glass melting furnaces at the facility using Equation 140-2 of this section:

$$CO_2 = \sum_{i=1}^k E_{CO_2i} \quad \text{Equation 140-2}$$

Where:

- CO_2 = Annual process CO_2 emissions from glass manufacturing facility (tonnes).
 E_{CO_2i} = Annual CO_2 emissions from glass melting furnace i (tonnes).
 k = Number of glass melting furnaces.

(vi) Calculate and report under ON.20 the combustion CO_2 emissions in the glass furnace according to the applicable requirements in ON.20.

ON.144 Sampling, Analysis, and Measurement Requirements

- (a) The person shall measure annual amounts of carbonate-based raw materials charged to each glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.
- (b) The person shall measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a laboratory using ASTM D3682 or any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 5), or the most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (c) The person shall determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.
- (d) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the monthly mass fraction (MF_i) of carbonate-based mineral i in Equation 140-1 of this section.
- (e) The person shall determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard, or use a value of 1.0 for the calcination fraction. This chemical analysis shall be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (f) The person shall measure the quantity of glass production. Equipment used to measure the production quantity shall be:

- (1) calibrated according to the manufacturer's instructions and
- (2) maintained to achieve an accuracy of plus or minus 5%.

ON.145 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.144, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.144 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
 - (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall,

- (i) Determine the sampling or measurement rate using the following Equation 140-3:

$$R = Q_{SAct}/Q_{SRequired} \qquad \text{Equation 140-3}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{S Required}$ = Quantity of samples or measurements required under ON.144

- (ii) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns raw material consumption, glass production or carbonate consumption, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

Table 140-1 - CO₂ Emission Factors for Carbonate-Based Minerals

Carbonate-Based Raw Material – Mineral	CO₂ Emission Factor^a
Limestone – CaCO ₃	0.43971
Dolomite – CaMg(CO ₃) ₂	0.47732
Sodium carbonate/soda ash – Na ₂ CO ₃	0.41492

^a Emission factors in units of tonnes of CO₂ emitted per tonne of carbonate-based mineral charged to the furnace.

ON.120 HCFC-22 Production and HFC-23 Destruction

ON.121 Activity Definition

For the purposes of this standard quantification method:

“HCFC-22 production and HFC-23 destruction” has the same meaning as in the Regulation.

“Person” means a person that engages in HCFC-22 Production or HFC-23 destruction.

ON.122 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.120 – ON.125, in an emission report prepared for a calendar year in respect of HCFC-22 production and HFC-23 destruction at a facility:

- (a) HFC-23 emissions from HCFC-22 production processes and HFC-23 destruction processes.

ON.123 Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart O Section 98.153.

ON.124 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance with U.S. EPA 40 CFR 98 Subpart O Section 98.154.

ON.125 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart O Section 98.155.

ON.130 Hydrogen Production

ON.131 Activity Definition

For the purposes of this standard quantification method:

“Hydrogen production” has the same meaning as in the Regulation.

“Person” means a person that engages in hydrogen production.

ON.132 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.130 – ON.135, in an emission report prepared for a calendar year in respect of hydrogen production at a facility:

- (a) Process CO₂ Emissions. The CO₂ process emissions from the hydrogen production process (tonnes).
- (b) Feedstock Consumption (if estimating emissions using mass balance approach in ON.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.
- (c) Annual hydrogen produced (tonnes), excluding any molecular hydrogen that is in the feedstock used in a steam methane reformer.

ON.133 Calculation of Greenhouse Gas Emissions

The person shall calculate and report CO₂ process emissions using the methods in paragraphs (a) or (b) of this section.

- (a) Continuous Emission Monitoring Systems. The person may calculate CO₂ process emissions using CEMS. The person shall comply with the requirements in section ON.20.
- (b) Feedstock Material Balance. The person may calculate CO₂ process emissions using the following method.
 - (1) Gaseous fuel and feedstock. The person shall calculate the annual CO₂ process emissions from gaseous fuel and feedstock according to Equation 130-1 of this section:

$$CO_2 = \left(\sum_{n=1}^k 3.664 * Fdstk_n * CC_n * \frac{MW}{MVC} \right) * 0.001 \quad \text{Equation 130-1}$$

Where:

- CO₂ = Annual CO₂ process emissions arising from fuel and feedstock consumption (tonnes/yr).
- Fdstk_n = Volume of the gaseous fuel and feedstock used in month n at reference temperature and pressure conditions (Rm³). If a

- mass flow meter is used, measure the gaseous product produced in month “n” in kg and replace the term “MW/MVC” with “1”.
- CC_n = Weighted average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n (Rm^3 at reference temperature and pressure conditions as used by the facility). If a mass flow meter is used, measure the feedstock used in month n in kg and replace the term “MW/MVC” with “1”.
- MW = Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the above $Fdstk_n$ (Rm^3/kg -mole). MVC can be $= 8.3145 * [273.16 + \text{reference temperature in } ^\circ C] / [\text{reference pressure in kilopascal}]$.
- k = Months in the year.
- 3.664 = Ratio of molecular weights, CO_2 to carbon.
- 0.001 = Conversion factor from kg to tonnes.

(2) Liquid fuel and feedstock. The person shall calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation 130-2 of this section:

$$CO_2 = \left(\sum_{n=1}^k 3.664 * Fdstk_n * CC_n \right) * 0.001 \quad \text{Equation 130-2}$$

Where:

- CO_2 = Annual CO_2 emissions arising from fuel and feedstock consumption (tonnes/yr).
- $Fdstk_n$ = Volume of the liquid fuel and feedstock used in month n (m^3 of fuel and feedstock). If a mass flow meter is used, measure the fuel and feedstock used in month n in kg and measure the carbon content of feedstock in kg C per kg of feedstock.
- CC_n = Weighted average carbon content of the liquid fuel and feedstock, from the results of daily analyses for month n (kg of C per m^3 of fuel and feedstock when the usage is measured in m^3 , or kg of C per kg of feedstock and fuel when the usage is measured in kg).
- k = Months in the year.
- 3.664 = Ratio of molecular weights, CO_2 to carbon.
- 0.001 = Conversion factor from kg to tonnes.

- (3) Solid fuel and feedstock. The person shall calculate the annual CO₂ process emissions from solid fuel and feedstock according to Equation 130-3 of this section:

$$CO_2 = \sum_{n=1}^k 3.664 * (Fdstk_n * CC_n) * 0.001$$

Equation 130-3

Where:

- CO₂ = Annual CO₂ emissions from fuel and feedstock consumption in tonnes per year month (tonnes/yr).
- Fdstk_n = Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).
- CC_n = Weighted average carbon content of the solid fuel and feedstock, from the results of daily analyses for month n (kg carbon per kg of fuel and feedstock).
- k = Months in the year.
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to tonnes.

- (c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with ON.23, then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The person shall report the combined stack emissions according to the CEMS methodology in ON.23.

ON.134 Sampling, Analysis, and Measurement Requirements

- (a) Persons using CEMS to estimate CO₂ emissions shall comply with the monitoring requirements in Calculation Methodology 4 of ON.23.
- (b) Persons using the methods in section ON.133 (b) or paragraph (c) of this section shall perform the following monitoring:
- (1) The person shall measure the feedstock consumption rate daily.
 - (2) The person shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in paragraph (c) of this section. For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily and a weighted average established for month n. Daily samples may be combined to generate a monthly composite sample for carbon analysis. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.

- (c) Persons shall quantify the hydrogen produced daily. Equipment used to measure the production quantity shall be:
 - (1) calibrated according to the manufacturer's instructions and
 - (2) maintained to achieve an accuracy of plus or minus 5%.
- (d) The calibration requirements under paragraph (c) do not apply to meters that are used for financial transactions if the supplier and purchaser do not have common owners and are not owned by subsidiaries or affiliates of the same company.
- (e) Persons shall quantify the CO₂ and CO collected and transferred off-site quarterly.
- (f) The person shall use the following methods, as applicable, to determine the carbon content of the feedstocks:
 - (1) Any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 5).
 - (2) The most appropriate method published by a consensus-based standards organization to determine the carbon content of the feedstocks. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

ON.135 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.134, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.134 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
 - (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
 - (i) Determine the sampling or measurement rate using the following Equation 130-4:

$$R = Q_{S \text{ Act}} / Q_{S \text{ Required}} \qquad \text{Equation 130-4}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage
Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.134

- (ii) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns raw material consumption or hydrogen production, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content..

ON.190 Indirect Useful Thermal Energy

ON.191 Activity Definition

For the purposes of this standard quantification method:

“Indirect Useful Thermal Energy” has the same meaning as in the Regulation.

“Person” means a person that engages in the use of indirect useful thermal energy at a facility.

ON.192 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.193 – ON.195, in an emission report prepared for a calendar year in respect of the use of indirect useful thermal energy:

- (a) Annual greenhouse gas emissions that would result from the generation of the indirect useful thermal energy calculated in accordance with ON.193, expressed in tonnes.
- (b) The amount of indirect useful thermal energy received by the facility, expressed in GJs.
- (c) The amount of thermal energy transferred out of the facility, expressed in GJs.
- (d) The fraction of non-biomass input into the combustion equipment at the facility that generated the indirect useful thermal energy.

ON.193 Calculation of GHG Emissions

- (a) A person shall use equation 190-1 to calculate annual CO₂e emissions from the generation of the indirect useful thermal energy, expressed in tonnes.

$$E_{is} = (Heat_{imported_{t-2}} - Heat_{exported_{t-2}}) \times NBF_{import_{t-2}} \times EF_{NGB}$$

Equation 190-1

Where:

E_{is} = Annual greenhouse gas emissions from the generation of the indirect useful thermal energy, expressed in tonnes CO₂e.

$Heat_{imported_{t-2}}$ = the amount of indirect useful thermal energy received by the facility in year t-2, expressed in GJs.

$Heat_{\text{exported}_t-2}$ = the amount of thermal energy transferred out of the facility in year t-2, expressed in GJs. If $Heat_{\text{exported}_t-2}$ is greater than $Heat_{\text{imported}_t-2}$, then $Heat_{\text{exported}_t-2}$ is equal to $Heat_{\text{imported}_t-2}$.

NBF_{import_t-2} = the non-biomass fraction of energy input into combustion equipment at the facility that generates the indirect useful thermal energy under $Heat_{\text{imported}_t-2}$.

EF_{NGB} = 0.061646.

ON.194 Sampling, Analysis, and Measurement Requirements

- (a) The person shall determine the quantity of indirect useful thermal energy using:
- (1) Measurements or records used for billing purposes, or
 - (2) Direct measurement using one of the following methods:
 - (i) Any applicable method listed in the Technical Reference Document section of this Guideline;
 - (ii) The most appropriate method published by a consensus-based standards organization; or
 - (iii) Where no appropriate method is published by a consensus-based standards organization, using industry standard methods, noting where such methods are used and what methods are used.
- (b) A person required to determine quantities of indirect useful thermal energy in accordance with this method shall recalibrate all flow meters:
- (1) Prior to the first calendar year for which GHG emissions are required to be reported pursuant to this method; or
 - (2) Upon replacement of a previously calibrated meter; or
 - (3) At least once every three years, or at the minimum frequency specified by the manufacturer.

ON.195 Procedures for Estimating Missing Data

Determination of quantity

- (a) Whenever sampling and measurement data required by ON.193 and ON.194 for the calculation of emissions is missing, the person shall ensure that the data is replaced using the following missing data procedures:
- (1) Determine the sampling or measurement rate using Equation 190-2:

$$R = Q_{\text{SAct}}/Q_{\text{SRequired}} \quad \text{Equation 190-2}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{SAct} = Quantity of actual samples or measurements obtained by the person

$Q_{S Required}$ = Quantity of samples or measurements required under ON.194

- (i) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period.
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the lowest monthly data value measured during the calendar year for which the calculation is made.
 - (C) If $R < 0.75$: replace the missing data with a value of zero.

ON.150 Iron and Steel Production

ON.151 Activity Definition

For the purposes of this standard quantification method:

“Iron and steel production” has the same meaning as in the Regulation.

“Person” means a person that engages in iron and steel production.

“Semi-finished steel shapes” means blooms, billets, slabs or ingots from the electric arc furnace or basic oxygen furnace that are later rolled into finished products such as beams, bars, or sheets.

ON.152 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.150 – ON.155, in an emission report prepared for a calendar year in respect of iron and steel production at a facility:

(a) Annual process CO₂ emissions (tonnes) for the following processes:

- (1) Taconite indurating furnace
- (2) Basic oxygen furnace (BOF)
- (3) Coke making operation
- (4) Sinter process
- (5) Electric arc furnace (EAF)
- (6) Argon-oxygen decarburization vessel
- (7) Direct reduction furnace
- (8) Blast furnace

(b) Annual production and usage quantities (tonnes) for the following processes:

- (1) Taconite indurating furnace – fired pellets produced on-site
- (2) BOF steel produced on-site
- (3) Coke making operation – coke produced and coal charged
- (4) Sinter process – sinter produced
- (5) EAF steel produced on-site
- (6) Argon-oxygen decarburization vessel – molten steel charged
- (7) Direct reduction furnace – iron produced
- (8) Liquid iron produced in the blast furnace.
- (9) Limestone used in the blast furnace
- (10) Dolomite used in the blast furnace

(c) CO₂, N₂O, and CH₄ emissions, not accounted for elsewhere in ON.150, from stationary combustion units using the methods specified in ON.20 (tonnes). Report these emissions from stationary combustion for each of the following devices:

- (1) Taconite indurating furnace
- (2) BOF
- (3) Coke oven batteries
- (4) Sintering furnace
- (5) EAF
- (6) Argon-oxygen decarburization vessel
- (7) Direct reduction furnace
- (8) Blast furnace
- (9) Any other stoves, boiler, process heaters, reheat furnaces and other combustion sources.

ON.153 Calculation of CO₂ Emissions

(a) Process CO₂ emissions. Determine process CO₂ emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in Calculation Methodology 4 of ON.23.

(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process CO₂ Emissions Calculation Methodology. Calculate CO₂ process emissions for each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, blast furnace, and direct reduction furnace using the following mass balance approaches specified in paragraphs (b)(1) through (b)(8). Specific process inputs or outputs that contribute less than 1 per cent of the total mass of carbon into or out of the process do not have to be included in the paragraphs (b)(1) through (b)(8) mass balances.

(1) Calculate taconite indurating furnace CO₂ emissions using Equation 150-1:

$$E_T = [(T \times C_T) - (P \times C_P) - (R \times C_R)] \times 3.664 \quad \text{Equation 150-1}$$

Where:

- E_T = Annual CO₂ emissions from taconite indurating furnace (tonnes);
- T = Annual mass of greenball (taconite) pellets fed to furnace (tonnes);

C_T	=	Carbon content of greenball (taconite) pellets (tonnes C/tonnes taconite pellets);
P	=	Annual mass of fired pellets produced by the furnace (tonnes);
C_P	=	Carbon content of fired pellets (tonnes C/tonnes fired pellets);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(2) Calculate basic oxygen process furnace CO₂ emissions using Equation 150-2:

$$E_{BOF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (R \times C_R)] \times 3.664$$

Equation 150-2

Where:

E_{BOF}	=	Annual CO ₂ emissions from basic oxygen furnaces (tonnes);
I	=	Annual mass of molten iron charged to furnace (tonnes);
C_I	=	Carbon content of molten iron (tonnes C/tonnes molten iron);
SC	=	Annual mass of ferrous scrap charged to furnace (tonnes);
C_{SC}	=	Carbon content of ferrous scrap (tonnes C/tonnes ferrous scrap);
FL	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C_{FL}	=	Carbon content of non-biomass flux materials (tonnes C/tonnes flux material);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C_{CAR}	=	Carbon content of non-biomass carbonaceous material (tonnes C/tonnes carbonaceous material);
ST	=	Annual mass of basic oxygen furnace semi-finished steel shapes, or molten raw steel produced by furnace (tonnes);
C_{ST}	=	Carbon content of steel (tonnes C/tonnes steel);
SL	=	Annual mass of slag produced by furnace (tonnes);
C_{SL}	=	Carbon content of slag (tonnes C/tonnes slag);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/tonnes residue);

(3) Calculate coke oven battery CO₂ emissions using Equation 150-3:

Equation 150-3

$$E_{\text{coke}} = [(CC \times C_{CC}) - (CO \times C_{CO}) - (BY \times C_{BY}) - (R \times C_R)] \times 3.664$$

- Where:
- E_{coke} = Annual CO₂ emissions from coke production (tonnes);
 - CC = Annual mass of coking coal and nonfuel carbonaceous material charged to battery (tonnes);
 - C_{CC} = Non-biomass carbon content of coking coal and nonfuel carbonaceous material (tonnes C/tonnes coking coal and nonfuel carbonaceous material);
 - CO = Annual mass of coke produced (tonnes);
 - C_{CO} = Carbon content of coke (tonnes C/tonnes coke);
 - BY = Annual mass of by-product from by-product coke oven battery (tonnes);
 - C_{BY} = Non-biomass carbon content of by-product (tonnes C/tonnes by-product);
 - R = Quantity of air pollution control residue collected (tonnes);
 - C_R = Carbon content of air pollution control residue (tonnes C/tonnes residue);
 - 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

(4) Calculate sinter process CO₂ emissions using Equation 150-4:

$$E_{\text{sinter}} = [(CAR \times C_{CAR}) + (FE \times C_{FE}) - (S \times C_S) - (R \times C_R)] \times 3.664 \quad \text{Equation 150-4}$$

Where:

- E_{sinter} = Annual CO₂ emissions from sinter process (tonnes);
- CAR = Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
- C_{CAR} = Carbon content of non-biomass carbonaceous material (tonnes C/tonnes carbonaceous material);
- FE = Annual mass of sinter feed material (tonnes);
- C_{FE} = Carbon content of sinter feed material (tonnes C/tonnes sinter feed material);
- S = Annual mass of sinter produced (tonnes);
- C_S = Carbon content of sinter produced (tonnes C/tonnes sinter);
- R = Quantity of air pollution control residue collected (tonnes);
- C_R = Carbon content of air pollution control residue (tonnes C/tonnes residue);
- 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

(5) Calculate electric arc furnace (EAF) CO₂ emissions using Equation 150-5:

$$E_{\text{EAF}} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (EL \times C_{EL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (R \times C_R)] \times 3.664$$

Equation 150-5

Where:

E_{EAF}	= Annual CO ₂ emissions from EAF (tonnes);
I	= Annual mass of direct reduced iron (if any) charged to furnace (tonnes);
C_I	= Carbon content of direct reduced iron (tonnes C/tonnes direct reduced iron);
SC	= Annual mass of ferrous scrap charged to furnace (tonnes);
C_{SC}	= Carbon content of ferrous scrap (tonnes C/tonnes ferrous scrap);
FL	= Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C_{FL}	= Carbon content of non-biomass flux materials (tonnes C/tonnes flux material);
EL	= Annual mass for carbon electrodes consumed (tonnes);
C_{EL}	= Carbon content of non-biomass carbon electrodes (tonnes C/tonnes carbon electrode);
CAR	= Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C_{CAR}	= Non-biomass carbon content of carbonaceous material (tonnes C/tonnes carbonaceous material);
ST	= Annual mass of electric arc furnace semi-finished steel shapes, or molten raw steel produced by furnace (tonnes);
C_{ST}	= Carbon content of steel (tonnes C/tonnes steel);
SL	= Annual mass of slag produced by furnace (tonnes);
C_{SL}	= Carbon content of slag (tonnes C/tonnes slag);
R	= Annual mass of air pollution control residue collected (tonnes);
C_R	= Carbon content of air pollution control residue (tonnes C/tonnes residue);
3.664	= Conversion factor from tonnes of C to tonnes of CO ₂ .

(6) Calculate argon-oxygen decarburization vessel CO₂ emissions using Equation 150-6:

$$E_{AOD} = [Steel \times (C_{in} - C_{out}) - (R \times C_R)] \times 3.664 \quad \text{Equation 150-6}$$

Where:

E_{AOD}	= Annual CO ₂ emissions from argon-oxygen decarburization vessels (tonnes);
Steel	= Annual mass of molten steel charged to vessel (tonnes);
C_{in}	= Carbon content of molten steel before decarburization (tonnes C/tonnes molten steel);
C_{out}	= Carbon content of molten steel after decarburization (tonnes C/tonnes molten steel);

- R = Annual mass of air pollution control residue collected (tonnes);
 C_R = Carbon content of air pollution control residue (tonnes C/tonnes residue);
 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

(7) Calculate direct reduction furnace CO₂ emissions using Equation 150-7:

$$E_{DR} = [(Ore \times C_{Ore}) + \sum(CAR \times C_{CAR}) + \sum(OT \times C_{OT}) - (I \times C_I) - (NM \times C_{NM}) - (R \times C_R)] \times 3.664$$

Equation 150-7

Where:

- E_{DR} = Annual CO₂ emissions from direct reduction furnace (tonnes);
 Ore = Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);
 C_{Ore} = Carbon content of iron ore or iron ore pellets (tonnes C/tonnes iron ore or iron ore pellets);
 CAR = Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);
 C_{CAR} = non-biomass carbon content of non-fuel carbonaceous materials (tonnes C/tonnes non-fuel carbonaceous material);
 OT = Annual mass of other materials charged to furnace (tonnes);
 C_{OT} = non-biomass carbon content of other materials (tonnes C/tonnes other materials);
 I = Annual mass of iron produced (tonnes);
 C_I = Carbon content of iron (tonnes C/tonnes iron);
 NM = Annual mass for non-metallic materials produced (tonnes);
 C_{NM} = Carbon content of non-metallic materials (tonnes C/tonnes non-metallic minerals);
 R = Annual mass of air pollution control residue collected (tonnes);
 C_R = Carbon content of air pollution control residue (tonnes C/tonnes residue);
 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

(8) Calculate blast furnace CO₂ emissions using Equation 150-8:

$$E_{BF} = [(Ore \times C_{Ore}) + \sum(CAR \times C_{CAR}) + \sum(F \times C_F) + \sum(OT \times C_{OT}) - (I \times C_I) - (NM \times C_{NM}) - (R \times C_R)] \times 3.664$$

Equation 150-8

Where:

- E_{BF} = Annual CO₂ emissions from blast furnace (tonnes);

Ore	= Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);
C _{Ore}	= Carbon content of iron ore or iron ore pellets (tonnes C/tonnes iron ore or iron ore pellets);
CAR	= Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);
C _{CAR}	= Non-biomass carbon content of non-fuel carbonaceous materials (tonnes C/tonnes non-fuel carbonaceous material);
F	= Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C _F	= Non-biomass carbon content of flux materials (tonnes C/tonnes flux material);
OT	= Annual mass of other materials charged to furnace (tonnes);
C _{OT}	= Non-biomass carbon content of other materials (tonnes C/tonnes other materials);
I	= Annual mass of iron produced (tonnes);
C _I	= Carbon content of iron (tonnes C/tonnes iron);
NM	= Annual mass for non-metallic materials produced (tonnes);
C _{NM}	= Carbon content of non-metallic materials (tonnes C/tonnes non-metallic minerals);
R	= Annual mass of air pollution control residue collected (tonnes);
C _R	= Carbon content of air pollution control residue (tonnes C/tonnes residue);
3.664	= Conversion factor from tonnes of C to tonnes of CO ₂ .

(9) Calculate total CO₂ emissions using Equation 150-9:

$$E_{CO_2} = E_T + E_{BOF} + E_{coke} + E_{sinter} + E_{EAF} + E_{AOD} + E_{DR} + E_{BF} \quad \text{Equation 150-9}$$

Where:

E _{CO2}	= Total CO ₂ emissions (tonnes);
E _T	= Emissions from taconite indurating furnace (tonnes);
E _{BOF}	= Emissions from basic oxygen furnace (BOF) (tonnes);
E _{coke}	= Emissions from coke production (tonnes);
E _{sinter}	= Emissions from sinter production (tonnes);
E _{EAF}	= Emissions from electric arc furnace (EAF) (tonnes);
E _{AOD}	= Emissions from argon-oxygen decarburization vessels (tonnes);
E _{DR}	= Emissions from direct reduction furnace (tonnes);
E _{BF}	= Emissions from blast furnace (tonnes);

(c) Calculate CO₂, N₂O, and CH₄ emissions, not accounted for elsewhere in ON.150, from stationary combustion units using the methods specified in ON.23 and ON.24 for each of the processes identified in ON.152(c).

ON.154 Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in the ON.153 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:
- (1) For iron ore, taconite pellets, and other iron-bearing materials, use ASTM E1915.
 - (2) For iron and ferrous scrap, use ASTM E1019.
 - (3) For coal, coke, and other carbonaceous materials (e.g., electrodes, etc.), use ASTM D5373 or ASTM D5142.
 - (4) For petroleum liquid based fuels and liquid waste-derived fuels, use ASTM D5291 and either ASTM D2502 or ASTM D2503.
 - (5) For steel, use one of the methods described in subparagraph (i) through (v):
 - (i) ASM CS-104 UNS No. G10460.
 - (ii) ISO/TR 15349-1: 1998.
 - (iii) ISO/TR 15349-3: 1998.
 - (iv) ASTM E415.
 - (v) ASTM E1019.
 - (6) For flux (i.e., limestone or dolomite) and slag, use ASTM C25.
 - (7) For fuels, determine carbon content and molecular weight (if applicable) using the applicable methods listed in ON.20.
 - (8) For steel production by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, sinter off gas, slag dust, etc.); use an online instrument that determines carbon content to $\pm 5\%$; or use sampling and analysis listed in ON.25; or any of the other analytical methods listed in this subsection or Technical Reference Document section of this Guideline (section 5); or methodologies using plant instruments used for accounting purposes.
 - (9) If a person is unable to use the methods listed in (1) – (8) above, the person shall use
 - (i) Any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 5). or

- (ii) The most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (b) Obtain carbon content from material vendor or supplier.
- (c) The person shall measure the quantity of production and material usage required to be reported in ON.152(b).
 - (1) Equipment used to measure the production quantity and material usage under ON.152(b) shall be:
 - (i) calibrated according to the manufacturer's instructions where available; or, where not available calibrated according to practices used for accounting purposes;
 - (ii) maintained to achieve an accuracy of plus or minus 5%.
 - (2) The person may use engineering estimates or mass balance along with measurements to determine:
 - (i) coking coal, and nonfuel carbonaceous material charged to battery; and
 - (ii) coke production in coke oven batteries.
 - (3) The person may use measurements of semi-finished steel shape dimensions, counts and densities to determine the quantity and mass of the semi-finished steel shapes.

ON.155 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.154, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.154 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
 - (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
 - (i) Determine the sampling or measurement rate using the following Equation 150-10:

$$R = Q_{S \text{ Act}}/Q_{S \text{ Required}} \quad \text{Equation 150-10}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

$Q_{S \text{ Act}}$ = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.154

(ii) Replace the missing data as follows,

- (A) 1. If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns the consumption of carbon-containing raw material, consumption of ferrous scrap, annual consumption of molten iron, consumption of coking coal, consumption of flux material, consumption of direct reduced iron pellets, consumption of carbon electrodes, consumption of ore, quantity of slag produced, consumption of greenball pellets, production of fired pellets, production of coke oven gas, production of metallurgical coke, quantity of air pollution control residue collected, quantity of other coke oven by-products, the quantity of steel processed or produced, quantity of gas from basic oxygen furnaces transferred, the production of sinter, the production of iron or the quantity of non-metallic by-products, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.160 LEAD PRODUCTION

ON.161 Activity Definition

For the purposes of this standard quantification method:

“Lead production” has the same meaning as in the Regulation.

“Person” means a person that engages in lead production.

ON.162 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.160 – ON.165, in an emission report prepared for a calendar year in respect of lead production at a facility:

- (a) Annual emissions of CO₂ at the facility level (tonnes).
- (b) Annual quantities of each carbon-containing input material used (tonnes).
- (c) Carbon content of each carbon-containing input material used (tonnes C/tonne input material).
- (d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used)
- (e) Annual lead production (tonnes)

ON.163 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- (a) Determine facility CO₂ emissions using continuous emissions monitoring systems (CEMS) as specified in Calculation Methodology 4 of ON.23.
- (b) Calculate total CO₂ emissions using Equation 160-1. Specific materials that contribute less than 1 per cent of the total carbon into the process do not have to be included in the calculation using Equation 160-1.

$$E_{Pb} = \sum_x (RA_x \times C_x) \times 3.664$$

Equation 160-1

Where:

- E_{Pb} = Annual CO₂ emissions from lead production (tonnes);
- RA_x = Annual quantity of material x used (tonnes);
- C_x = Carbon content of material x (tonnes C/tonnes of x);
- 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

ON.164 Sampling, Analysis, and Measurement Requirements

The annual mass of each material introduced into the smelting furnace shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

The average carbon content of each material introduced into the smelting furnace shall be determined as specified under paragraph (a), (b), or (c) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:
- (1) For solid carbonaceous reducing agents and carbon electrodes, use ASTM D5373.
 - (2) For liquid reducing agents, use one of the methods described in subparagraph (i) through (iv):
 - (i) ASTM D2502.
 - (ii) ASTM D2503.
 - (iii) ASTM D3238.
 - (iv) ASTM D5291.
 - (3) For gaseous reducing agents, use one of the methods described in subparagraph (i) or (ii):
 - (i) ASTM D1945.
 - (ii) ASTM D1946.
 - (4) For waste-based carbon-containing material, determine carbon content by:
 - (i) Operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant; or
 - (ii) Using engineering estimates to derive the carbon content of the waste-based carbon containing material.
- (b) Obtain carbon content from material vendor or supplier.
- (c) The person shall measure the lead production quantity. Equipment used to measure the production quantity shall be:
- (1) calibrated according to the manufacturer's instructions and
 - (2) maintained to achieve an accuracy of plus or minus 5%.

ON.165 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.164, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.164 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (3) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
- (i) Determine the sampling or measurement rate using the following Equation 160-2:

$$R = Q_{S \text{ Act}} / Q_{S \text{ Required}} \quad \text{Equation 160-2}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

$Q_{S \text{ Act}}$ = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.164

- (i) Replace the missing data as follows,
- (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
- (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (4) When the missing data concerns raw material consumption or the production of lead or other products, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (5) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS

1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.170 Lime Production

ON.171 Activity Definition

For the purposes of this standard quantification method:

“Lime production” has the same meaning as in the Regulation.

“Person” means a person that engages in lime production.

ON.172 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.170 – ON.175, in an emission report prepared for a calendar year in respect of lime production at a facility:

- (a) CO₂ process emission from lime production for all kilns (excluding emissions from fuel combustion) in tonnes.
- (b) CO₂ process emissions from lime production (tonnes) for all kilns combined and the following information if the process CO₂ emissions are calculated according to the procedures specified in ON.173(b):
 - (1) For lime production:
 - (i) The emission factor (tonne CO₂/tonne) for each lime type for each month.
 - (ii) The quantity of each type of lime produced (tonnes) each month.
 - (iii) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.
 - (iv) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.
 - (2) For the production of calcined byproducts and wastes:
 - (i) The emission factor (tonne CO₂/tonne) for each calcined byproduct/waste type for each quarter.
 - (ii) The quantity of each type of calcined byproduct/waste type produced each quarter.
 - (iii) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each quarter.
 - (iv) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each quarter.
- (c) CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methodologies and reporting requirements specified in ON.173(c) (tonnes).
- (d) The annual quantity of each type of lime produced (tonnes).

Production Parameters

- (e) The annual emissions from the production of iron coated lime.
- (1) CO₂, CH₄ and N₂O emissions from fuel combustion from the production of iron coated lime, expressed in tonnes CO₂e.
 - (2) Process CO₂ emissions from the production of iron coated lime calculated using ON.173(b), expressed in tonnes.

ON.173 Calculation of Greenhouse Gas Emissions from Kilns

- (a) Determine process CO₂ emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
- (1) Continuous emissions monitoring systems (CEMS) as specified in Calculation Methodology 4 of ON.23.
 - (2) Calculate the sum of CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.
- (b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions as the sum of emissions from lime production, using the method specified in paragraph (b)(1) of this section.
- (1) CO₂ Process Emissions. Calculate CO₂ emissions from the production of each type of lime using Equation 170-1 and a plant-specific lime emission factor and a plant-specific calcined byproduct/waste emission factor as specified in this section.

$$E_{CO_2} = \sum_m^{12} \sum_i [QL_{mi} \times EF_{QL_{mi}}] + \sum_q^4 \sum_j [CBW_{qj} \times EF_{CBW_{qj}}] \quad \text{Equation 170-1}$$

Where:

- E_{CO_2} = Annual process CO₂ emissions in tonnes/yr.
- QL_{mi} = Quantity of lime type i produced in month m, tonnes.
- $EF_{QL_{mi}}$ = Emission factor of lime type i produced in month m, computed as specified in paragraph (b)(2) of this section, tonnes CO₂/tonne lime.
- CBW_{qj} = Quantity of calcined byproduct and waste type j produced in quarter q, tonnes.
- $EF_{CBW_{qj}}$ = Emission factor of calcined byproduct/waste type j produced in quarter q, computed as specified in paragraph (b)(3) of this section, tonnes CO₂/tonne byproduct and waste.

- (2) Monthly Lime Emission Factor. Calculate a plant-specific lime emission factor (EF_{QL}) for each type of lime and month based on the per cent of measured CaO and MgO content in lime and using Equation 170-2.

$$EF_{QL} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092) \quad \text{Equation 170-2}$$

Where:

- EF_{QL} = Process CO₂ emission factor for lime produced, tonnes CO₂/tonne lime.
- f_{CaO} = CaO content of lime, calculated by subtracting CaO content of lime in uncalcined CaCO₃ remaining in lime from total CaO content of lime, tonnes CaO/tonne lime. For double burnt lime, calculate the CaO content of the double burnt lime by subtracting the CaO content in the dolomite lime from total CaO content of the double burnt lime, expressed in tonnes CaO/tonne double burnt lime.
- 0.785 = Ratio of molecular weights of CO₂ to CaO.
- f_{MgO} = MgO content of lime, calculated by subtracting MgO content of lime in uncalcined MgCO₃ remaining in lime from total MgO content of lime, tonnes MgO/tonne lime.
- 1.092 = Ratio of molecular weights of CO₂ to MgO

- (3) Quarterly Calcined Byproduct/Waste Emission Factor. The calcined byproduct/waste emission factor shall be calculated using Equation 170-3.

$$EF_{CBW} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092) \quad \text{Equation 170-3}$$

Where:

- EF_{CBW} = Process CO₂ Emission factor for calcined byproduct and waste, tonnes CO₂/tonne calcined byproduct and waste.
- f_{CaO} = CaO content of byproduct and waste, calculated by subtracting CaO content of byproduct and waste in uncalcined CaCO₃ remaining in calcined byproduct and waste from total CaO content of byproduct and waste, tonnes CaO/tonne byproduct and waste.
- 0.785 = Ratio of molecular weights of CO₂ to CaO .
- f_{MgO} = MgO content of byproduct and waste, calculated by subtracting MgO content of byproduct and waste in uncalcined MgCO₃ remaining in byproduct and waste from total MgO content of byproduct and waste, tonnes MgO/tonne byproduct and waste .
- 1.092 = Ratio of molecular weights of CO₂ to MgO

- (c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O emissions from stationary fuel combustion emissions following the calculation methodologies specified in ON.20. The person that primarily combusts biomass-derived fuels; and combusts fossil fuels only during periods of start-up, shut-down, or malfunction; may report CO₂ emissions from fossil fuels using the Calculation methodology 1 in ON.23. "Pure" means that the

biomass-derived fuels account for 97 per cent of the total amount of carbon in the fuels burned.

The person that reports CO₂ emissions from kilns using continuous emissions monitoring systems pursuant to ON.173(a)(1) may report:

- (1) Fuel combustion CO₂ emissions in kilns by subtracting the total emissions calculated using ON.173(a)(1) from the process CO₂ emissions calculated using ON.173(b); or
- (2) Fuel combustion CO₂ emissions in kilns using the Calculation Methodology 1 in ON.23 and fuel sampling based on the same plant techniques used for accounting purposes.

ON.174 Sampling, Analysis, and Measurement Requirements

- (a) The person shall determine the chemical composition (CaO and MgO contents) of each type of lime and each type of calcined byproduct/waste according to the relevant methods and protocols contained in of this section. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample shall be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct/waste type produced.
 - (1) ASTM C25.
 - (2) The National Lime Association's CO₂ Emissions Calculation Protocol for the Lime Industry English Units.
 - (3) Any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 5).
 - (4) The most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
 - (5) A mass balance method for double burnt lime.
- (b) The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum. Equipment used to measure the production quantity shall be:
 - (1) calibrated according to the manufacturer's instructions and
 - (2) maintained to achieve an accuracy of plus or minus 5%.

- (c) The quantity of calcined byproduct/waste sold is to be estimated monthly using direct measurements (such as rail and truck scales) of calcined byproduct/waste sales for each calcined byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than annually for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).
- (d) The person shall follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO₂ Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

ON.175 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.174, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.174 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:

- (i) Determine the sampling or measurement rate using the following Equation 170-4:

$$R = Q_{S \text{ Act}}/Q_{S \text{ Required}} \quad \text{Equation 170-4}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{S Act} = Quantity of actual samples or measurements obtained by the person

Q_{S Required} = Quantity of samples or measurements required under ON.174

- (ii) Replace the missing data as follows,
- (A) If R ≥ 0.9: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the

- person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns lime production or the production of calcined by-products and waste, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.290 Magnesium Production

ON. 291 Activity Definition

For the purpose of this method, the following definitions apply:

“Cover gas” means a greenhouse gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air and includes but is not limited to SF₆ and HFC–134a.

“Carrier gas” means a gas mixed with a cover gas to transport and dilute the cover gas.

“Heels” means any material remaining in a tank following unloading, delivery, or discharge of the transported cargo.

“Magnesium producer” means a person who engages in magnesium production

“Magnesium production” has the same meaning as in the Regulation.

ON.292 Greenhouse Gas Reporting Requirements

(a) A magnesium producer shall set out the following information, calculated for the calendar year using standard quantification methods ON.290- – ON.295, in an emission report prepared for a calendar year in respect of magnesium production:

- (1) The total annual emissions of each greenhouse gas listed in Table 1 of the Regulation resulting from the use of the greenhouse gas as a cover or carrier gas in magnesium production expressed in tonnes of CO₂e per year calculated using the methods in ON.293. An explanation of any change greater than 30 per cent in the facility’s cover gas usage rate from the previous calendar year.
- (2) A description of any new melt protection technologies adopted to account for reduced or increased greenhouse gas emissions in the previous reporting period.

Production Parameter

(b) The total annual quantity of magnesium produced or processed, by process type, in tonnes.

ON.293 Calculation of GHG Emissions

(a) A magnesium producer shall use Equation 290-1 or 290-2 to calculate the mass of GHG emissions from the consumption of cover or carrier gases expressed in tonnes,

(1) Monitoring changes in container masses and inventories:

$$E_x = (I_{B,x} - I_{E,x} + A_x - D_x) \times 0.001 \quad \text{Equation 290-1}$$

Where:

- E_x = Total GHG emissions from the consumption of cover or carrier gases expressed in tonnes
- $IB_{,x}$ = Inventory of cover gas or carrier gas x stored in cylinders or other containers at the beginning of the reporting period, including heels expressed in kg;
- $I_{E,x}$ = Inventory of each cover gas or carrier gas x stored in cylinders or other containers at the end of the reporting period, including heels expressed in kg;
- A_x = Acquisitions of cover gas or carrier gas x during the reporting period, including heels in cylinders or other containers returned to the magnesium production or processing facility expressed in kg;.
- D_x = Transfers of cover gas or carrier gas x off-site during the reporting period, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas supplier expressed in kg;
- 0.001 = Conversion factor from kg to tonnes; and
- X = Each cover gas or carrier gas that is a GHG contained in Schedule 1 of the Regulation.

(2) Monitoring changes in masses of individual containers as contents are used:

$$E_x = \sum_{p=1}^n Q_p \times 0.001 \quad \text{Equation 290-2}$$

Where:

- E_x = Total GHG emissions from the consumption of cover or carrier gases expressed in tonnes
- Q_p = Mass of the cover or carrier gas consumed calculated in accordance with Equation 290-3 expressed in kg;
- n = Number of cylinders or other containers in period p ; and
- 0.001 = Conversion factor from kg to tonnes.

(b) For the purposes of Equation 290-2, the mass of the cover or carrier gas consumed over the period p for an individual container shall be estimated by using Equation 290-3:

$$Q_p = M_B - M_E \quad \text{Equation 290-3}$$

Where:

- Q_p = Mass of cover or carrier gas consumed over the period p
- M_B = Mass of the cylinder or container's contents expressed in kg at the beginning of period p ; and
- M_E = Mass of the cylinder or container's contents expressed in kg at the end of period p .

(c) Notwithstanding (b) above, if a facility has mass flow controllers (MFC) and the capacity to track and record MFC measurements to estimate total gas usage, the mass of each cover or carrier gas monitored may be used as the value for Q_p in Equation 290-2 expressed in kg.

ON.294 Sampling, Analysis, and Measurement Requirements

Determination of quantities of cover and carrier gases and mass flows

- (a) The magnesium producer required to determine quantities of cover and carrier gases for the purposes of using this method shall determine changes in cylinder or container weights and inventories as follows:
 - (1) Using scales or load cells with an accuracy of 1 per cent of full scale or better, accounting for the tare weights of the cylinders or other containers or
 - (2) Using gas masses or weights provided by the gas supplier (e.g., for the contents of containers containing new gas or for the heels remaining in cylinders or other containers returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards in (c) are met.
- (b) The magnesium producer required to determine quantities of cover and carrier gases for the purposes of using Equations 290-2 and 290-3 shall monitor and record cylinder and other container identities and masses as follows:
 - (1) Track the identities and masses of cylinders and other containers leaving and entering storage with check-out and check-in sheets and procedures.
 - (2) Measure masses of cylinders and other containers returning to storage immediately before the cylinders or other containers are put back into storage.
- (c) The magnesium producer required to monitor the mass flows of the cover or carrier gas into the gas distribution system for the purposes of ON.293(c) shall use gas flow meters or mass flow controllers, with an accuracy of 1 per cent of full scale or better.

Equipment Calibration

- (d) The magnesium producer required to determine quantities of cover and carrier gases pursuant to this method shall calibrate all flow meters, scales,

and load cells prior to its first use for the purposes of this method using calibration procedures specified by the equipment manufacturer.

- (e) The magnesium producer required to determine quantities of cover and carrier gases pursuant to this method shall recalibrate equipment mentioned in (d) at the minimum frequency specified by the manufacturer.
- (f) The person shall measure the magnesium production quantity. Equipment used to measure the production quantity shall be:
 - (1) calibrated according to the manufacturer's instructions and
 - (2) maintained an accuracy of plus or minus 5%.

ON.295 Procedures for Missing Data

Determination of quantity

- (a) Whenever sampling and measurement data required by ON.293 for the calculation of emissions is unavailable, the person shall ensure that the data is substituted using the following missing data procedures:
 - (1) Replace missing data on the emissions of cover or carrier gases by multiplying magnesium production during the missing data period by the average cover or carrier gas usage rate calculated using Equation 290-4.

$$R_x = \left(\frac{C_x}{Mg} \right) \times 0.001 \quad \text{Equation 290-4}$$

Where:

- R_x = Usage rate of a particular cover gas or carrier gas x over the period of comparable operation expressed in tonnes gas/tonne Mg;
- C_x = Consumption of a particular cover gas or carrier gas x over the period of comparable operation expressed in kg;
- Mg = Magnesium produced or fed into the process over the period of comparable operation expressed in tonnes;
- 0.001 = Conversion factor from kg to tonnes; and
- X = Each cover gas or carrier gas that is a GHG listed in Schedule 1 of the Regulation.

(2) Unavailable weights

Where the calculation of the before and after weight of a cylinder or other container is required, and a precise weight is not available, the magnesium producer shall assume that the cylinder or other container, except for the heel, was emptied.

(3) Records for missing data

The magnesium producer shall ensure that where data is missing, the following information is recorded;

- (i) the length of time the data was missing for each cover gas or carrier gas,
- (ii) the method used to estimate emissions in the absence of the data, and
- (iii) the quantity of emissions estimated using that method.

ON.280 Mobile Equipment Operation (for reference purposes only)

ON.281 Activity Definition

For the purposes of this standard quantification method:

“Mobile equipment operation” means the operation, related to production as part of the normal operations of a facility, of mobile industrial equipment used for transportation or movement of substances, materials and products at the facility, including tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes and bulldozers and excluding on-road vehicles within the meaning of the *On-Road Vehicle and Engine Emission Regulations (Canada)*, aircraft and marine vessels..

“Person” means a person that engages in mobile equipment operation.

“Mobile equipment operator” means an owner and operator of a facility that has mobile equipment and who is required to report under s. 2(1) of the Regulation.

“Mobile equipment” means mobile industrial equipment used for on-site transportation or movement of substances, materials and products at the facility including tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes and bulldozers but does not include on-road vehicles, aircrafts or marine vessel.

“On-road vehicle” has the same meaning as in the *On-Road Vehicle and Engine Emission Regulations (Canada)*

ON.282 Greenhouse Gas Reporting Requirements

This standard quantification method is included for reference purposes only and the use of mandatory language, such as “shall”, throughout this method is also included for reference purposes only and is not intended to create any substantive obligations.

(a) A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.280 – ON.286, in an emission report prepared for a calendar year in respect of mobile equipment operation at a facility:

- (1) The total annual CO₂, CO₂ from biomass, CH₄ and N₂O emissions that would result from the complete combustion of each fuel type used by all mobile sources at the facility calculated in accordance with ON.283 and ON 284 expressed in tonnes.

- (2) The total annual quantity of each type of fuel used by all mobile equipment at the facility expressed in kilolitres calculated in accordance with ON.285.

ON.283 Calculation of CO₂ Emissions

- (a) The person shall use one of the following calculation methodologies to calculate the total annual CO₂ emissions, including total annual CO₂ emissions from biomass:

- (1) Calculation Methodology 1- Fossil Fuel Usage:

$$E_{totalCO2} = Q_i \times EF_i \quad \text{Equation 280-1}$$

Where:

$E_{totalCO2}$ = total annual CO₂ emissions that would result from the complete combustion of each fuel type used by all mobile equipment at the facility expressed in tonnes;

Q_i = total annual quantity of fuel i used in mobile equipment expressed in litres;

EF_i = Emission factor for fuel i expressed in tonnes of CO₂/litre

- (2) Calculation Methodology 2 – Hours of operation:

Step 1 $E_{i,k CO2} = (h_{i,k} \times h_{pi,k} \times LF_{i,k} \times BSFC_{i,k}) \times EF_{i,CO2}$ **Equation 280-2**

Step 2 $E_{Total,i,CO2} = \sum_k E_{i,k,CO2}$ **Equation 280-3**

Where:

$E_{i,k,CO2}$ = Total annual CO₂ emissions from mobile equipment k for fuel i expressed in tonnes;

$h_{i,k}$ = Total annual hours of operation for mobile equipment k for fuel i expressed in hours;

$h_{pi,k}$ = Rated equipment horsepower for mobile equipment k for fuel i expressed in horsepower;

$LF_{i,k}$ = Load factor for mobile equipment k for fuel i expressed in a range between 0 and 1;

$BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment k for fuel i expressed in litres/horsepower-per hour;

EF_i = Emission factor for fuel i expressed in tonnes of CO₂/litre.

$E_{Total,i,CO2}$ = Total annual CO₂ emissions that would result from the complete combustion of each fuel type used by all mobile equipment at the facility expressed in tonnes;

(3) Calculation Methodology 3 - Environment Canada Reporting:

Determine the total annual CO₂ emissions reported to Environment Canada's Greenhouse Gas Emissions Reporting Program pursuant to any submissions that the person was required to make to the Federal government under section 46 or 71 of the *Canadian Environmental Protection Act, 1999* for each fuel type used by all mobile sources at the facility expressed in tonnes.

ON.284 Calculation of CH₄ and N₂O Emissions

(a) The person shall use one of the following calculation methodologies to calculate the annual CH₄ and N₂O emissions:

(1) Calculation Methodology 1- Fossil Fuel Usage:

$$E_{total,i,g} = Q_i \times EF_{i,g} \times (1/10^6) \quad \text{Equation 280-4}$$

Where:

$E_{total,i,g}$ = Total annual emissions of greenhouse gas g (i.e. CH₄ or N₂O) from mobile equipment for fuel i expressed in tonnes;

Q_i = Total annual quantity of fuel i expressed in litres;

$EF_{i,g}$ = Emission factor for CH₄ or N₂O for fuel i expressed in grams/litre;

$(1/10^6)$ = Conversion factor from grams to tonnes.

(2) Calculation Methodology 2 – Hours of Operation:

Step 1 $E_{i,k,g} = (h_{i,k} \times h_{pi,k} \times LF_{i,k} \times BSFC_{i,k}) \times EF_{i,g} \times (1/10^6) \quad \text{Equation 280-5}$

Step 2 $E_{Total,i,g} = \sum_k E_{i,g,k} \quad \text{Equation 280-6}$

Where:

$E_{i,k,g}$ = Total annual greenhouse gas g (CH₄ or N₂O) emissions from mobile equipment k for fuel i expressed in tonnes;

$h_{i,k}$ = Total annual hours of operation for mobile equipment k for fuel i expressed in hours;

$hp_{i,k}$ = Rated equipment horsepower for mobile equipment k for fuel i expressed in horsepower;

$LF_{i,k}$ = Load factor for mobile equipment k for fuel i expressed in a range between 0 and 1;

$BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment k for fuel i expressed in litres/horsepower-per hour;

$EF_{i,g}$ = Emission factor for greenhouse gas g (i.e. CH₄ or N₂O) for fuel i as listed in ON.20 expressed in grams/litre;

(1/10⁶) = Conversion factor from grams to metric tons;

$E_{Total,i,g}$ = Total Annual emissions greenhouse gas g (CH₄ or N₂O) for fuel i expressed in tonnes.

(3) Calculation Methodology 3 – Environment Canada Reporting:

Determine the total annual CH₄ and N₂O emissions reported to Environment Canada's Greenhouse Gas Emissions Reporting Program pursuant to any submissions that the person was required to make to the Federal government under section 46 or 71 of the *Canadian Environmental Protection Act, 1999* for each fuel type used by all mobile sources at the facility expressed in tonnes.

ON.285 Sampling, Analysis, and Measurement Requirements

Emission Factors:

(a) The person shall use one of the following emissions factors when using Methodology 1 and 2 in ON.283 and ON.284:

- (1) The emission factor for the fuel type listed in ON.20, or
- (2) A mobile-operator-specific emissions factor

Fuel Quantities:

(b) The person shall, on an annual basis, determine the fuel volume required in Methodology 1 in ON.283 and ON.284 by using vendor receipts in the calendar year, dipstick measurement, or other means.

(c) The person may use engineering estimates when determining the portion of the biofuel in a mixture of biofuel and fossil fuel for the purpose of Methodology 1 in ON.283 and ON.284.

Hours of Operation:

(d) The person shall use the records kept by the facility setting out the hours of operation for the mobile equipment subject to the report when using Methodology 2 in ON.283 and ON.284.

ON.286 Procedures for estimating missing data

- (a) Where the missing data concerns fuel quantity, the person shall generate the replacement data from best estimates based on all of the data relating to the mobile equipment.

ON.400 Natural Gas Distribution

ON.401 Activity Definitions

For the purpose of this method, the following definitions apply:

“Custody transfer station” means a location in Ontario at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer.

“Distributor” means a person who engages in natural gas distribution as defined in the Regulation.

“Petroleum Product Supplier” has the same meaning as “supplier” in ON. 390.

ON.402 Greenhouse Gas Reporting Requirements

(a) The distributor shall set out the following information, calculated for the calendar year using standard quantification methods ON.400– ON.406, in an emission report prepared for a calendar year in respect of natural gas distribution:

- (1) Annual CO₂ emissions, expressed in tonnes, that would result from the complete combustion or oxidation of the quantities of natural gas distributed, calculated in accordance with ON.403.
- (2) Annual CH₄ and N₂O emissions, expressed in tonnes, that would result from the complete combustion or oxidation of the quantities of natural gas distributed, calculated in accordance with ON.404.
- (3) Annual quantity of natural gas, excluding any natural gas derived from biomass, received by the distributor at its custody transfer stations, expressed in Rm³.
- (4) Annual quantity of natural gas, excluding any natural gas derived from biomass, that is placed into storage after the custody transfer station, expressed in Rm³.
- (5) Annual quantity of natural gas, excluding any natural gas derived from biomass, that is withdrawn from storage after the custody transfer station, expressed in Rm³.
- (6) Annual quantity of natural gas delivered to another distributor or exported out of Ontario, expressed in Rm³.

- (7) Report the following information for each capped facility of a capped participant to which the person has supplied natural gas during the calendar year,
- (i) Organization name;
 - (ii) Facility location;
 - (iii) Annual quantity of natural gas delivered, expressed in Rm^3 .
- (8) Annual quantity of natural gas delivered to the facility with GHGID 1144 at 1741 River Road, Sarnia, and that the capped participant listed in Table 20-8 pays the natural gas distributor for in the year. This quantity shall be reported separately for each of the capped participants in Table 20-8.

ON.403 Calculation of CO₂ Emissions

Natural Gas received at custody transfer stations

- (a) A distributor shall use one of the following methods to calculate annual CO₂ emissions that would result from the complete combustion or oxidation of the natural gas received at the custody transfer station “i” in the calendar year, expressed in tonnes.

- (1) Calculation Methodology 1. Use Equation 400-1 to calculate the annual CO₂ emissions that would result from the complete combustion or oxidation of the natural gas received at the custody transfer station:

$$\text{CO}_{2i} = 0.001 * \sum \text{NG}_h * \text{HHV}_h * \text{EF}_h \quad \text{Equation 400-1}$$

Where:

- CO_{2i} = Annual CO₂ emissions from the complete combustion or oxidation of the natural gas received by the distributor at its custody transfer stations, expressed in tonnes.
- NG_h = Annual quantity of natural gas received, excluding any natural gas derived from biomass or gas that does not contain any carbon, at the custody transfer station in period “h”, expressed in Rm^3 .
- HHV_h = Default high heat value contained in Table 400-1 or a distributor-specific higher heating value determined in accordance with ON.405, expressed in GJ per Rm^3 or GJ per litre.
- EF_h = Default CO₂ emission factor contained in Table 400-1 or a distributor-specific CO₂ emission factor determined in accordance with ON.405, expressed in kg of CO₂ per GJ.

0.001 = Conversion factor from kilograms to tonnes.

- (2) Calculation Methodology 2. Use Equation 400-2 to calculate the annual rCO₂ emissions that would result from the complete combustion or oxidation of the natural gas received at the custody transfer station:

$$CO_{2i} = \sum_h NG_h * EF_h \quad \text{Equation 400-2}$$

Where:

CO_{2i} = Annual CO₂ emissions from the complete combustion of the natural gas received by the distributor at its custody transfer stations, expressed in tonnes.

NG_h = Annual quantity of natural gas received, excluding any natural gas derived from biomass or gas that does not contain any carbon, at the custody transfer station in period “h”, expressed in Rm³.

EF_h = Default CO₂ emission factor contained in Table 400-2 or a distributor-specific CO₂ emission factor determined in accordance with ON.405, expressed in kg of CO₂ per Rm³.

- (b) In addition to the requirements in (a) above, each distributor shall calculate the following CO₂ emissions, expressed in tonnes:

- (1) Use Equation 400-3 to calculate the annual CO₂ emissions that would result from the complete combustion or oxidation of natural gas that is distributed to another distributor “j” or exported out of Ontario:

$$CO_{2j} = NG_j * EF \quad \text{Equation 400-3}$$

Where:

CO_{2j} = Annual CO₂ emissions from the complete combustion of the natural gas that is distributed to another distributor or exported out of Ontario, expressed in tonnes.

NG_j = Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, distributed to another distributor “j” or exported out of Ontario, expressed in Rm³.

EF = Default CO₂ emission factor contained in Table 400-2 or a distributor-specific CO₂ emission factor determined in accordance with ON.405, expressed in tonnes of CO₂ per Rm³.

- (2) Use Equation 400-4 to calculate the annual CO₂ emissions that would result from the complete combustion or oxidation of natural gas, excluding any natural gas derived from biomass, that is distributed to capped facilities, of capped participant “k”; or distributed to the facility with GHG ID 1144 at 1741 River Road, Sarnia, and that the capped participants identified in Table 20-8 pay a natural gas distributor for in the year.

$$CO_{2k} = NG_k * EF \quad \text{Equation 400-4}$$

Where:

CO_{2k} = Annual CO₂ emissions that would result from the complete combustion of the natural gas that is distributed to capped facilities, of capped participant “k” , expressed in tonnes.

NG_k = Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, distributed to capped facilities, of capped participant “k”.

EF = Default CO₂ emission factor contained in Table 400-2 or a distributor-specific CO₂ emission factor determined in accordance with ON.405, expressed in tonnes of CO₂ per Rm³.

- (3) Use Equation 400-5 to calculate the annual CO₂ emissions that would result from the complete combustion or oxidation of the quantity of natural gas that represents the net change in natural gas stored during the calendar year:

$$CO_{2l} = [Fuel_1 - Fuel_2] * EF \quad \text{Equation 400-5}$$

Where:

CO_{2l} = Annual CO₂ emissions that would result from the complete combustion of natural gas that represents the net change in natural gas stored within the calendar year, expressed in tonnes.

Fuel₁ = Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, put into storage after the custody transfer station during the calendar year, expressed in Rm³

Fuel₂ = Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, that is taken

out of storage after the custody transfer station during the calendar year, expressed in Rm^3 .

EF = Default CO_2 emission factor contained in Table 400-2 or a distributor-specific CO_2 emission factor determined in accordance with ON.405 expressed in tonnes of CO_2 per Rm^3 .

(4) Use Equation 400-6 to calculate the total annual CO_2 emissions.

$$\text{CO}_{2f} = \sum \text{CO}_{2i} - \sum \text{CO}_{2j} - \sum \text{CO}_{2k} - \sum \text{CO}_{2l} \quad \text{Equation 400-6}$$

ON.404 Calculation of CH_4 and N_2O Emissions

(a) A distributor shall use Equation 400-7 to calculate annual CH_4 emissions and Equation 400-8 to calculate annual N_2O emissions that would result from the complete combustion or oxidation of natural gas, expressed in tonnes.

$$\text{CH}_4 = \text{CO}_{2f} \times \text{EF}_{\text{CH}_4} \times 0.000001 \div \text{EF}_h \quad \text{Equation 400-7}$$

$$\text{N}_2\text{O} = \text{CO}_{2f} \times \text{EF}_{\text{N}_2\text{O}} \times 0.000001 \div \text{EF}_h \quad \text{Equation 400-8}$$

Where:

- CH_4 = Annual CH_4 emissions, expressed in tonnes.
- N_2O = Annual N_2O emissions, expressed in tonnes.
- EF_h = CO_2 emission factor used to calculate CO_2 emissions in ON.403(a), expressed in tonnes of CO_2 per Rm^3 .
- EF_{CH_4} = Default CH_4 emissions factor contained in Table 20-4 using the value for "Residential, Construction, Commercial/Institutional, Agriculture", expressed in grams of CH_4 per Rm^3 .
- $\text{EF}_{\text{N}_2\text{O}}$ = Default N_2O emissions factor contained in Table 20-4 using the value for "Residential, Construction, Commercial/Institutional, Agriculture, expressed in grams of N_2O per Rm^3 .

ON.405 Sampling, Analysis, and Measurement Requirements

(a) Determination of quantity of natural gas

(1) The distributor required to determine quantities of natural gas pursuant to this method shall determine those quantities using standard quantification practices used for:

(i) Billing purposes in the natural gas industry; or

- (ii) Non-billing purposes in the natural gas industry.
- (2) If the distributor determines the quantities of natural gas using 1(ii), the minimum frequency of measurement shall be the same as the one used in the quantification practices under 1(i).
 - (3) The distributor required to determine quantities of natural gas for the purposes of using Equations 400-1, 400-2 or 400-3 of this method shall use the volume of natural gas measured at the custody transfer meter(s).
 - (4) The distributor referred to in (3) may use measurements or records of deliveries in place of the the volume of natural gas measured at the custody transfer meter(s).
 - (5) The distributor required to determine quantities of natural gas for the purposes of using Equation 400-4 of this method shall measure the volume of natural gas at all customer meter(s) at the facility .
 - (6) The distributor required to determine quantities of natural gas for the purposes of using Equation 400-5 of this section shall measure natural gas as follows:
 - (i) Fuel₁ shall be measured at the on-system storage injection meters or at the meters measuring natural gas to be liquefied.
 - (ii) Fuel₂ shall be measured at the meters used for measuring on-system storage withdrawals or LNG vaporization injection.
- (b) Determination of high heating values (HHV).
- (1) The distributor required to use Equation 400-1 shall, when using a distributor-specific HHV, calculate the HHV in accordance with an appropriate standard test published by a consensus-based standards organization using one of the following measurements:
 - (i) If the distributor takes its own HHV measurements in accordance with established business practices, then its own measurements shall be used.
 - (ii) If the distributor does not make its own measurements according to established business practices, it shall use its delivering pipeline measurements.
- (c) Determination of distributor-specific emission factors.
- (1) A distributor using a distributor-specific emission factor in accordance with this method shall conduct compositional analysis using an appropriate standard method published by a consensus-based standards organization to determine the CO₂ emission factor.

- (d) Equipment Calibration (which may also be referred to as Equipment verification).
- (1) A distributor required to determine quantities of natural gas in accordance with this method shall calibrate orifice, nozzle, and venturi flow meters:
 - (i) Prior to its first use for the purposes of this method; and
 - (ii) Using in-situ calibration of the differential pressure (ΔP), total pressure and temperature transmitters.
 - (2) For flow meters used for natural gas, the distributor may follow the requirements under the laws and regulations of Measurement Canada for electricity and gas or as specified by the equipment manufacturer.
 - (3) A distributor required to determine quantities of natural gas pursuant to this method shall recalibrate equipment mentioned in (1) or (2) at the frequency specified by:
 - (i) Any applicable method listed in the Technical Reference Document section of this Guideline;
 - (ii) The most appropriate method published by a consensus-based standards organization;
 - (iii) Using methods and requirements in accordance with the requirements under the laws and regulation of Measurement Canada for electricity and gas; or
 - (iv) The manufacturer's directions.

ON.406 Procedures for Estimating Missing Data

- (a) Whenever a value for natural gas, HHV or EF is required by this method and is unavailable during a calendar year or part thereof, the distributor shall substitute a value for the missing data in accordance with the following:
- (1) Substitute the missing quantity of natural gas with quantities derived from:
 - (i) The delivering pipeline metered deliveries at the custody transfer station or
 - (ii) Nominations and scheduled delivery quantities.
 - (2) Substitute the missing HHV value with:
 - (i) Delivering pipeline measurements;
 - (ii) The default HHV provided in Table 400-1; or,

- (iii) Where values relating to a distributor-specific emission factor are unavailable, substitute the missing EF value with the value from Table 400-1 or 400-2 as applicable.

Table 400-1 —Default Factors for Calculation Methodology 1

Fuel	Default High Heating Value Factor	Default CO₂ Emission Factor (kg CO₂ /GJ)
Natural Gas	0.038 GJ/Sm ³	49.03

Table 400-2—Default Values for Calculation Methodology 2

Fuel	Unit	Default CO₂ Emission Value (tonnes CO₂/Unit)
Natural Gas	cubic metres (Sm ³)	0.001863

ON.310 Nitric Acid Production

ON.311 Activity Definition

For the purposes of this standard quantification method:

“Nitric acid production” has the same meaning as in the Regulation.

“Person” means a person that engages in nitric acid production.

ON.312 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.310 – ON.315, in an emission report prepared for a calendar year in respect of nitric acid production at a facility:

- (a) Total N₂O process emissions as required by this method (tonnes)
- (b) Total CO₂ emissions from the reducing agents used in the non-selective catalytic reduction units (tonnes CO₂), calculated using ON.313(i).
- (c) Total CH₄ emissions from unreacted methane in reducing agents used in the non-selective catalytic reduction unit (tonnes CH₄), calculate using ON.313(i).

Production Parameter

- (d) Annual nitric acid production from the nitric acid facility (tonnes, 100 per cent acid basis).

ON.313 Calculation of GHG emissions

- (a) The person shall determine annual N₂O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.
 - (1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.
 - (2) Use a continuous monitoring system (CEMS).
- (b) The person shall conduct an annual performance test according to paragraphs (b)(1) through (b)(2) of this section.
 - (1) The person is required to measure N₂O emissions from the absorber tail gas vent for each nitric acid train or after the gas vent of the N₂O abatement technology, using the methods specified in ON.314(b) through (d),.
 - (2) The person shall measure the production rate during the performance test and calculate the production rate for the test period in tonnes (100 per cent acid basis) per hour.
- (c) The person shall determine an N₂O emissions factor to use in Equation 310-3a or 310-3b of this section according to the following:

- (1) Using the results of the performance test in paragraph (b) of this section, the person shall calculate an average site-specific emission factor for each nitric acid train “t” according to Equation 310-1 of this section:

$$EF_{N_2O_t} = \frac{\sum_1^n \frac{C_{N_2O} * 1.828 \times 10^{-6} * Q}{P}}{n} \quad \text{Equation 310-1}$$

Where:

- $EF_{N_2O_t}$ = Average site-specific N_2O emissions factor for nitric acid train “t” (kg N_2O generated/tonne nitric acid produced, 100 per cent acid basis).
- C_{N_2O} = N_2O concentration for each test run during the performance test (ppm N_2O).
- 1.862×10^{-6} = Conversion factor (kg/dSm³-ppm N_2O).
- Q = Volumetric flow rate of effluent gas for each test run during the performance test (dSm³/hr).
- P = Production rate for each test run during the performance test (tonnes nitric acid produced per hour, 100 per cent acid basis).
- n = Number of test runs.

- (d) If applicable, the person is required to determine the destruction efficiency for each N_2O abatement technology according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.
- (1) Use the manufacturer’s specified destruction efficiency.
 - (2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. The person shall document how process knowledge (if applicable) was used to determine the destruction efficiency.
 - (3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.
- (e) If applicable, the person is required to determine the abatement factor for each N_2O abatement technology. The abatement factor is calculated for each nitric acid train according to Equation 310-2 of this section.

$$AF_{N_t} = \frac{P_{at \text{ Abate}}}{P_{at}} \quad \text{Equation 310-2}$$

Where:

- AF_{N_t} = Abatement factor of N₂O abatement technology at nitric acid train “t” (fraction of annual production that abatement technology is operating).
- P_{a_t} = Total annual nitric acid production from nitric acid train “t” (tonne acid produced, 100 per cent acid basis).
- $P_{a_t \text{ Abate}}$ = Annual nitric acid production from nitric acid train “t” during which N₂O abatement was used (tonne acid produced, 100 per cent acid basis).

- (f) The person shall determine the annual amount of nitric acid produced and the annual amount of nitric acid produced while each N₂O abatement technology is operating from each nitric acid train (100 per cent basis).
- (g) The person shall calculate N₂O emissions for each nitric acid train by multiplying the emissions factor (determined in Equation 310-1 of this section) by the annual nitric acid production and accounting for N₂O abatement, according to Equation 310-3a (for measurements before the abatement technology) or 310-3b (for measurements after the abatement technology) of this section:

$$E_{N_2O_t} = \sum_{N=1}^z \frac{EF_{N_2O_t} * P_{a_t} * (1 - (DF_{N_t} * AF_{N_t}))}{1000} \quad \text{Equation 310-3a}$$

$$E_{N_2O_t} = \frac{EF_{N_2O_t} * P_{a_t}}{1000} \quad \text{Equation 310-3b}$$

Where:

- $E_{N_2O_t}$ = N₂O mass emissions per year for nitric acid train “t” (tonnes).
- $EF_{N_2O_t}$ = Average site-specific N₂O emissions factor for nitric acid train “t” (kg N₂O generated/tonne acid produced, 100 per cent acid basis).
- P_{a_t} = Annual nitric acid production from the train “t” (tonne acid produced, 100 per cent acid basis).
- DF_{N_t} = Destruction efficiency of N₂O abatement technology N that is used on nitric acid train “t” (per cent of N₂O removed from air stream).
- AF_{N_t} = Abatement factor of N₂O abatement technology for nitric acid train “t” (fraction of annual production that abatement technology is operating).
- 1000 = Conversion factor (kg/tonne).
- z = Number of different N₂O abatement technologies.

- (h) The person shall determine the annual nitric acid production emissions combined from all nitric acid trains at the facility using Equation 310-4 of this section:

$$N_2O = \sum_{t=1}^m E_{N_2O_t} \quad \text{Equation 310-4}$$

Where:

- N_2O = Annual process N_2O emissions from nitric acid production facility (tonnes)
 $E_{N_2O_t}$ = N_2O mass emissions per year for nitric acid train “t” (tonnes).
m = Number of nitric acid trains.

- (i) The person shall determine the annual emissions of CO_2 and CH_4 from reducing agents used in the non-selective catalytic reduction (NSCR) unit using Equations 310-5 and 310-6 of this section.

$$E_{ra_CO_2} = Q_a \times (1 - M_s) \times C_a \times 3.664 \quad \text{Equation 310-5}$$

$$E_{ra_CH_4} = Q_a \times (M_s) \times C_{CH_4} \quad \text{Equation 310-6}$$

Where:

- $E_{ra_CO_2}$ = Annual CO_2 emissions from other reducing agents or material used (tonnes);
 $E_{ra_CH_4}$ = Annual CH_4 emissions from unreacted methane in the reducing agent (tonnes)
 Q_a = Annual quantity of reducing agents or material used in the NSCR unit expressed in tonnes if it is a solid, Rm^3 at reference temperature and pressure conditions as used by the facility if it is a gas, or kilolitres if it is a liquid;
 M_s = Fraction of reducing agents or materials that did not react in the NSCR unit based on engineering estimates or design;
 C_a = Carbon content of reducing agents or material used expressed in tonnes carbon per tonne of solid, tonnes carbon per Rm^3 of gas, or tonnes carbon per kilolitre of liquid.;
 C_{CH_4} = methane content of the reducing agent or material used expressed in tonnes methane per tonne of solid, tonnes of methane per Rm^3 of gas, or tonnes methane per kiloliter of liquid;
3.664 = ratio of molecular weights, carbon dioxide to carbon.

ON.314 Sampling, Analysis, and Measurement Requirements

- (a) The person shall conduct a new performance test and calculate a new site-specific emissions factor as specified in the following paragraphs.

- (1) Conduct the performance test at least once per year.

- (2) Conduct the performance test when the nitric acid production process is changed, specifically when abatement equipment is installed.
- (b) The person shall measure the N₂O concentration during the performance test using one of the following methods.
- (1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.
 - (2) ASTM D6348.
 - (3) A method based on the use of non-dispersive infrared (NDIR) analyzer within a stack monitoring system where the method is equivalent to EPA method 320, any equivalent method published by Environment Canada or other Provinces.
 - (4) The most appropriate method published by a consensus-based standards organization, if such a method exists.
 - (5) If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (c) The person shall determine the production rate(s) (100 per cent basis) from each nitric acid train during the performance test according to one of the following methods.
- (1) Direct measurement of production and concentration (such as using flow meters, weigh scales, for production and concentration measurements).
 - (2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).
- (d) The person shall conduct all performance tests in conjunction with the applicable methods. For each test, the facility shall prepare an emission factor determination report that shall include the following items.
- (1) Analysis of samples, determination of emissions, and raw data.
 - (2) All information and data used to derive the emissions factor(s).
 - (3) The production rate during each test and how it was determined.
- (e) The person shall determine the monthly nitric acid production quantity and the monthly nitric acid production quantity during which N₂O abatement technology is operating from each nitric acid train according to the methods in paragraphs (c)(1) or (c)(2) of this section. Equipment used to measure the production quantity shall be:
- (1) calibrated according to the manufacturer's instructions and
 - (2) maintained to achieve an accuracy of plus or minus 5%.

- (f) The person shall determine the annual nitric acid production quantity and the annual nitric acid production quantity during which N₂O abatement technology is operating for each train by summing the respective monthly nitric acid production quantities. Equipment used to measure the production quantity shall be:
- (1) calibrated according to the manufacturer's instructions and
 - (2) maintained to achieve an accuracy of plus or minus 5%.

ON.315 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.314, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.314 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (1) When data determined on the basis of the performance test provided for in ON.314 is missing, conduct a new performance test;
 - (2) When the missing data concerns carbon content, temperature, pressure or gas concentration, other than data prescribed in the performance test the person shall:
 - (i) Determine the sampling or measurement rate using the following Equation 310-7:

$$R = Q_{S \text{ Act}} / Q_{S \text{ Required}} \quad \text{Equation 310-7}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

Q_{S Act} = Quantity of actual samples or measurements obtained by the person

Q_{S Required} = Quantity of samples or measurements required under ON.314

- (ii) Replace the missing data as follows,
 - (A) If R ≥ 0.9: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the period for which the data is missing. If no data are available from before that period,

- the person shall use the first available data from after the period for which the data is missing;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the report year for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (3) When the missing data concerns nitric acid production or a gas flow rate, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (4) When the missing data concerns the malfunction of a CEMS beyond 90 days, the data must be generated by another CEM system or valid performance test method.

ON.230 Operation of Equipment for a Transmission System or a Distribution System (Electricity)

ON.231 Activity Definition

For the purposes of this standard quantification method:

“Automated mass-flow measurement” means the use of mass-flow meters attached to electrical power distribution equipment to directly measure the amount of SF₆ added to equipment.

“Electricity transmission and distribution” has the same meaning as “operation of equipment for a transmission system or a distribution system (electricity)” in the Regulation.

“Person” means a person that engages in electricity transmission or distribution.

“PFC” means perfluoroethane, perfluoropropane, perfluorobutane, perfluorocyclobutane, perfluoropentane, perfluorohexane.

“Storage containers” includes cylinders, gas carts, and other storage containers, but does not include electrical power distribution equipment.

“Total nameplate capacity” means the full and proper charge of electrical power distribution equipment.

“Weigh-scale measurement” means measuring the SF₆ or PFC in a storage container before and after its contents are added to electrical power distribution equipment with the difference being equal to the SF₆ or PFC added to the equipment.

ON.232 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.230 – ON.235, in an emission report prepared for a calendar year in respect of electricity transmission and distribution at a facility:

- (a) The SF₆ and PFC emissions from electricity transmission and distribution and distribution calculated in accordance with ON.233(a) and (b).

ON.233 Calculation of SF₆ and PFC Emissions

- (a) A person shall use one of the following calculation methodologies to calculate SF₆ emissions
 - (1) Mass Balance Methodology.
 - (i) Calculate the change in inventory of SF₆ in storage using Equation 230-1.

$$\Delta S_{Inv} = S_{Inv-Begin} - S_{Inv-End}$$

Equation 230-1

Where:

- ΔS_{Inv} = Change in inventory of SF₆ in storage expressed in kilograms
- $S_{Inv-Begin}$ = Quantity of SF₆ in storage at the beginning of the reporting period expressed in kilograms;
- $S_{Inv-End}$ = Quantity of SF₆ in storage at the end of the reporting period expressed in kilograms

- (ii) Calculate the amount of all SF₆ acquired during the year that is contained either in storage containers or in electrical power distribution equipment using Equation 230-2.

$$S_{PA} = S_{Cyl} + S_{Equip} + S_{Recyc-ret} \quad \text{Equation 230-2}$$

Where:

- S_{PA} = Sum of all SF₆ acquired during the year that is contained either in storage containers or in electrical power distribution equipment expressed in kilograms;
- S_{Cyl} = Quantity of SF₆ in storage containers obtained from producers or distributors expressed in kilograms;
- S_{Equip} = Quantity of SF₆ stored or contained inside equipment provided by electrical power distribution equipment manufacturers expressed in kilograms;
- $S_{Recyc-ret}$ = Quantity of SF₆ returned to site after off-site recycling expressed in kilograms.

- (iii) Calculate the sum of all SF₆ transferred out of the facility during the year either in storage containers or in electrical power distribution equipment using Equation 230-3.

$$S_{SD} = S_{Sales} + S_{Returns} + S_{Destruct} + S_{Recyc-off} \quad \text{Equation 230-3}$$

Where:

- S_{SD} = Sum of all SF₆ transferred out of the facility during the year either in storage containers or in electrical power distribution equipment expressed in kilograms;
- S_{Sales} = Quantity of SF₆ sold or transferred to other facilities including SF₆ that is left in electrical power distribution equipment that is sold expressed in kilograms;

- S_{Returns} = Quantity of SF₆ returned to suppliers expressed in kilograms;
- S_{Destruct} = Quantity of SF₆ sent to destruction facilities expressed in kilograms;
- $S_{\text{Recyc-off}}$ = Quantity of SF₆ sent off-site for recycling expressed in kilograms.

(iv) Calculate the net increase in total nameplate capacity of electrical power distribution equipment that uses SF₆ using Equation 230-4.

$$\Delta S_{\text{Cap}} = S_{\text{Cap-new}} - S_{\text{Cap-retire}} \quad \text{Equation 230-4}$$

Where:

- ΔS_{Cap} = Net increase in total nameplate capacity of electrical power distribution equipment that uses SF₆ expressed in kilograms
- $S_{\text{Cap-new}}$ = Total nameplate capacity of new electrical power distribution equipment at proper full charge expressed in kilograms;
- $S_{\text{Cap-retire}}$ = Total nameplate capacity of electrical power distribution equipment that has been retired, sold or transferred at proper full charge expressed in kilograms.

(v) Calculate total emissions for the reporting period using Equation 230-5.

$$S = (\Delta S_{\text{Inv}} + S_{\text{PA}} - S_{\text{SD}} - \Delta S_{\text{Cap}}) / 1,000 \quad \text{Equation 230-5}$$

Where:

- S = Total annual SF₆ emissions expressed in tonnes;
- ΔS_{Inv} = Change in inventory of SF₆ in storage expressed in kilograms calculated in accordance with Equation 230-1;
- S_{PA} = Sum of all SF₆ acquired that is contained either in storage containers or in electrical power distribution equipment expressed in kilograms, calculated in accordance with Equation 230-2;
- S_{SD} = Sum of all SF₆ transferred out of the facility during the year that is contained either in storage containers or in electrical power distribution equipment expressed in kilograms calculated in accordance with Equation 230-3;

ΔS_{Cap} = Net increase in total nameplate capacity of electrical power distribution equipment using SF₆ expressed in kilograms calculated in accordance with Equation 230-4

1,000 = Factor to convert kilograms to tonnes.

(2) Direct Measurement Methodology.

- (i) SF₆ emissions from the operations phase shall be calculated by directly measuring the mass of SF₆ added to electrical power distribution equipment during the operation phase using automated mass-flow measurement or weigh-scale measurement in accordance with Equation 230-6.

$$S_O = \sum_i^N s_i \quad \text{Equation 230-6}$$

Where:

S_O = Annual SF₆ emissions during the operation phase expressed in kilograms;

N = Number of SF₆ additions in a given year;

s_i = SF₆ added to electrical power distribution equipment during addition i , expressed in kilograms

- (ii) SF₆ emissions from the decommissioning phase shall be calculated by directly measuring the amount of SF₆ collected from any decommissioned electrical power distribution equipment calculated in accordance with Equation 230-7.

$$S_D = \sum_i^N (NC_i - S_i) \quad \text{Equation 230-7}$$

Where:

S_D = Annual SF₆ emissions during decommissioning phase expressed in kilograms;

N = Number of units of electrical power distribution equipment decommissioned in a given year;

NC_i = Nameplate capacity of decommissioned electrical power distribution equipment i , expressed in kilograms;

S_i = SF₆ collected from decommissioned electrical power distribution equipment i , expressed in kilograms.

- (iii) Total annual SF₆ emissions are calculated according to Equation 230-8.

$$S = \frac{S_O + S_D}{1,000} \quad \text{Equation 230-8}$$

Where:

- S = Annual SF₆ emissions expressed in tonnes;
- S_O = Annual SF₆ emissions during operation phase expressed in kilograms;
- S_D = Annual SF₆ emissions during decommissioning phase expressed in kilograms.

- (b) A person shall use the methods in (a) to calculate the emissions from PFCs, substituting PFCs for SF₆ and making all other necessary substitutions in Equations 230-1 through 230-8.

ON.234 Sampling, Analysis, and Measurement Requirements

- (a) When using the calculation methodology in ON.233(a)(1), the person shall determine changes in cylinder or container weights and inventories as follows:
- (1) Using scales or load cells with an accuracy of 1 per cent of full scale or better, accounting for the tare weights of the cylinders or other containers; or
 - (2) Using gas masses or weights provided by the gas supplier (e.g., for the contents of containers containing new gas or for the heels remaining in cylinders or other containers returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards in (c) are met.
- (b) When using the calculation methodology in ON.233(a)(1), a person shall monitor and record cylinder and other container identities and masses as follows:
- (1) Track the identities and masses of cylinders and other containers leaving and entering storage with check-out and check-in sheets and procedures.
 - (2) Measure masses of cylinders and other containers returning to storage immediately before the cylinders or other containers are put back into storage.
- (c) When using the calculation methodologies in ON.233(a)(2) or the corresponding method required by ON.233 (b), a person shall measure additions of SF₆ or PFCs during the operation phase using a measuring instrument such as a flowmeter or weigh scale.
- (d) When using the calculation methodologies in ON.233(a)(2) or the corresponding method required by ON.233 (b), a person shall calibrate equipment used to measure the mass of SF₆ or PFCs as follows.
- (1) For automated mass-flow measurement, equipment shall be calibrated according to the calibration procedure specified by manufacturer.

- (2) For weigh-scale measurement, equipment shall be calibrated every 6 months by weighing objects of pre-determined mass and zeroing the weigh scale accordingly.

ON.235 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.234, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of Quantity

- (b) Whenever sampling and measurement data required by ON.234 for the calculation of emissions is unavailable the person shall ensure that the data is substituted using the following missing data procedures:

- (1) Determine the sampling or measurement rate that was used using Equation 230-9:

$$R = \frac{QS_{Act}}{QS_{Required}} \quad \text{Equation 230-9}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

QS_{Act} = Quantity of actual samples or measurements obtained by the person

QS_{Required} = Quantity of samples or measurements required under ON.230

- (2) Substitute the missing data as follows,
 - (i) If $R \geq 0.9$: substitute the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
 - (ii) If $0.75 \leq R < 0.9$: substitute the missing data with the highest data value sampled or analyzed during the reporting period for which the calculation is required;
 - (iii) If $R < 0.75$: substitute the missing data with the highest data value sampled or analyzed during the 3 preceding years;
- (3) When the missing data concerns gas quantity, the person shall generate the replacement data from best estimates based on all of the data relating to the processes.
- (4) When the missing data relates to electrical power distribution equipment capacity, the person shall estimate the replacement data on the basis of

an equivalent nominal SF₆ and PFC gas capacity, and on repair,
replacement and maintenance data for similar pieces of equipment.

ON.350 Operation of Equipment Related to Natural Gas

ON.351 Activity Definition

For the purposes of this standard quantification method:

“Blowdown vent stack emissions” mean natural gas and/or CO₂ released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

“Calibrated bag” means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

“Centrifugal compressor” means any equipment that increases the pressure of a process natural gas or CO₂ by centrifugal action, employing rotating movement of the driven shaft.

“Centrifugal compressor dry seals” mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO₂ from escaping to the atmosphere.

“Centrifugal compressor dry seals emissions” mean natural gas or CO₂ 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 seal degassing venting emissions” mean emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO₂. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

“Component” means each metal to metal joint or seal of non-welded 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 natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

“Continuous bleed” means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

“Custody-transfer”_means the transfer of product from one gas company to another gas company, excluding transfers between companies who have same parent company.

“Damage events”_means damages to gas pipelines and surface facilities resulting from natural causes or incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Incidents causing pipeline damages may include hits on surface facilities and dig-ins. Specific incident examples of dig-ins include grader/dozer/scrapper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, saw cutting, cable/pipe plowing, vertical augering/drilling, trencher excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

“De-methanizer” means the natural gas processing unit that separates methane-rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

“Equipment leak detection” means the process of identifying emissions from equipment, components, and other point sources.

“Farm taps”_mean pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers.

“Field gas”_means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

“Flare”, for the purposes of ON.350, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

“Flare combustion efficiency” means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

“Fugitive emissions”_means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other liquids or gases.

“Fugitive equipment leaks” means those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

“Gas conditions”_mean the actual temperature, volume, and pressure of a gas sample.

“High-bleed pneumatic devices”_means automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator

controller where it vents (bleeds) to the atmosphere at a rate in excess of 0.17 standard cubic meters per hour.

“Intermittent-bleed pneumatic devices”_mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously.

“Liquefied natural gas (LNG)”_means natural gas that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

“Liquefied natural gas (LNG) storage” means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re- liquefy boil-off-gas, re-condensers, and vapourization units for re-gasification of the liquefied natural gas.

“LNG boiloff gas”_means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

“LNG import equipment” means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system.

“LNG export equipment” means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in Canada.

“Low-bleed pneumatic devices”_mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta- pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

“Meter-regulating station”_means a station that meters the flow rate, regulates the pressure, or both, of natural gas in a natural gas distribution system. This does not include customer meters, customer regulators, or farm taps.

Natural gas distribution” means all natural gas equipment downstream of gate station inlet valves where pressure reduction and/or measuring occurs for eventual delivery of natural gas to consumers. Some natural gas distribution systems receive gas from gas batteries rather than from transmission pipelines and typically transport odourized natural gas.

“Natural gas 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 transmission pipelines” means a high pressure pipeline (and associated equipment) transporting sellable quality natural gas from production or natural gas processing to natural gas distribution systems before delivery to customers. In some cases natural gas is delivered directly from natural gas transmission pipelines to farms and industrial end users along the pipeline route.

“Onshore natural gas transmission compression” means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines, into storage or at times directly to industrial customers or farms located along the pipeline route. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment.

“Operation of equipment related to natural gas ” has the same meaning as in the Regulation.

“Operating pressure”_means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

“Person” means a person that engages in operation of equipment related to natural gas.

“Pump means” a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

“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 emissions”_means hydrocarbon 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 gas stream 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 the compressed gas stream that escapes to the atmosphere.

“Re-condenser” means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

“Reservoir”_means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

“Underground natural gas storage” means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the underground natural gas storage site that inject and recover natural gas into and from the underground reservoirs.

“Vapour 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.

“Vapourization unit” means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

ON.352 Greenhouse Gas Reporting Requirements

(a) A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.350 – ON.355, in an emission report prepared for a calendar year in respect of Operation of equipment related to natural gas:

(1) CO₂ and CH₄ (and N₂O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (f) of this section.

(b) For onshore natural gas transmission compression and natural gas transmission pipelines, report CO₂, CH₄ and N₂O emissions from the following sources:

(1) Compressor venting (from the following sources):

- (i) Reciprocating compressors in accordance with ON.353(a)(9).
- (ii) Centrifugal compressors in accordance with ON.353(a)(8).
- (iii) Blowdown vent stacks in accordance with ON.353(a)(5).
- (iv) Natural gas continuous high-bleed pneumatic devices in accordance with ON.353(a)(1).
- (v) Natural gas pneumatic pumps in accordance with ON.353(a)(2).
- (vi) Natural gas continuous low-bleed pneumatic device venting in accordance with ON.353(a)(3).
- (vii) Natural gas intermittent (low and high) bleed pneumatic device (including compressor starters) venting in accordance with

ON.353(a)(4).

- (viii) Other venting emission sources in accordance with ON.353(a)(15).
 - (2) Compressor fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters in accordance with ON.353(a)(10) or ON.353(a)(11).
 - (3) Compressor station flaring in accordance with ON.353(a)(7).
 - (4) Compressor other fugitive emission sources in accordance with ON.353(a)(15).
 - (5) Pipeline flaring in accordance with ON.353(a)(7).
 - (6) Pipeline below grade meters and regulators and valve fugitives in accordance with ON.353(a)(11).
 - (7) Pipeline other fugitive emission sources not covered in (b)(6), or (b)(10) (including, but not limited to, farm taps ≤ 700 kPa, pipe leaks, and customer meter sets) in accordance with ON.353(a)(15).
 - (8) Pipeline other venting emission sources in accordance with ON.353(a)(15).
 - (9) Transmission storage tanks in accordance with ON.353(a)(16).
 - (10) Damage events in accordance with ON.353(a)(6).
- (c) For underground natural gas storage, report CO₂, CH₄ and N₂O emissions from the following sources:
- (1) Venting (from the following sources):
 - (i) Reciprocating compressors in accordance with ON.353(a)(9).
 - (ii) Centrifugal compressors in accordance with ON.353(a)(8).
 - (iii) Natural gas continuous high-bleed pneumatic devices in accordance with ON.353(a)(1).
 - (iv) Natural gas pneumatic pumps in accordance with ON.353(a)(2).
 - (v) Natural gas continuous low-bleed pneumatic device venting in accordance with ON.353(a)(3).
 - (vi) Natural gas intermittent (low and high) bleed pneumatic device (including compressor starters) venting in accordance with ON.353(a)(4).
 - (vii) Other venting emission sources in accordance with ON.353(a)(15).
 - (2) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters in accordance with ON.353(a)(10), ON.353(a)(11).

- (3) Flares in accordance with ON.353(a)(7).
 - (4) Other fugitive emission sources. ON.353(a)(15).
- (d) For LNG storage, report CO₂, CH₄ and N₂O emissions from the following sources:
- (1) Venting (from the following sources):
 - (i) Reciprocating compressors in accordance with ON.353(a)(9).
 - (ii) Centrifugal compressors in accordance with ON.353(a)(8).
 - (iii) Other venting emission sources in accordance with ON.353(a)(15).
 - (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources in accordance with ON.353(a)(10), ON.353(a)(11).
 - (3) Flares in accordance with ON.353(a)(7).
 - (4) Other fugitive emission sources in accordance with ON.353(a)(15).
- (e) LNG import and export equipment, report CO₂, CH₄ and N₂O emissions from the following sources:
- (1) Venting (from the following sources):
 - (i) Reciprocating compressors in accordance with ON.353(a)(9).
 - (ii) Centrifugal compressors in accordance with ON.353(a)(8).
 - (iii) Blowdown vent stacks (including damage events) in accordance with ON.353(a)(5).
 - (iv) Other venting emission sources in accordance with ON.353(a)(15).
 - (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources in accordance with ON.353(a)(10), ON.353(a)(11).
 - (3) Flares in accordance with ON.353(a)(7).
 - (4) Other fugitive emission sources in accordance with ON.353(a)(15).
- (f) For natural gas distribution, report CO₂, CH₄ and N₂O emissions from the following sources:
- (1) Equipment leaks from equipment at above grade metering- regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open- ended lines in accordance with ON.353(a)(11).
 - (2) Equipment leaks from vaults at below grade metering-regulating stations in accordance with ON.353(a)(11).
 - (3) Pipeline main fugitive equipment leaks in accordance with ON.353(a)(11).

- (4) Service line fugitive equipment leaks in accordance with ON.353(a)(11).
- (5) Pipeline flaring in accordance with ON.353(a)(7).
- (6) Flares in accordance with ON.353(a)(7).
- (7) Damage events in accordance with ON.353(a)(6).
- (8) Other fugitive emission sources (including, but not limited to, farm taps, and customer meter sets) in accordance with ON.353(a)(15).
- (9) Venting (from the following sources):
 - (i) Natural gas continuous high-bleed pneumatic devices in accordance with ON.353(a)(1).
 - (ii) Natural gas pneumatic pumps in accordance with ON.353(a)(2).
 - (iii) Natural gas continuous low-bleed pneumatic device venting in accordance with ON.353(a)(3).
 - (iv) Natural gas intermittent (low and high) bleed pneumatic device (including compressor starters) venting in accordance with ON.353(a)(4).
 - (v) Other venting emission sources in accordance with ON.353(a)(15).

ON.353 Calculation of Greenhouse Gas Emissions

(a) A person shall use the following calculation methodologies to calculate CO₂, CH₄ and N₂O emissions:

- (1) Natural gas continuous high-bleed pneumatic device venting A person required to report pursuant to this quantification method shall calculate emissions from a natural gas pneumatic continuous high-bleed flow control device venting using the methods specified in paragraph (a)(1)(i) below when the device is metered.

When a continuous high bleed device is metered, the method specified in paragraph (a)(1)(i) must be used unless the count of metered devices in a transmission or distribution company in Ontario is less than 25 continuous high bleed pneumatic devices, in which case either method (a)(1)(i) or (a)(1)(ii) may be used.

For unmetered devices, and optionally for metered devices where count of metered continuous high-bleed devices is less than 25, the person shall use the method specified in paragraph (a)(1)(ii).

- (i) Calculate vented emissions for metered high-bleed pneumatic devices using the following equation:

$$E_s = Q_j \quad \text{Equation 350-1}$$

Where:

E_s = Annual natural gas volumetric emissions for pneumatic continuous high-bleed devices where gas is metered (Sm^3/y).

Q_j = Natural gas consumption for meter j (Sm^3/y).

- (ii) Calculate vented emissions for unmetered continuous high-bleed pneumatic devices using the following equation:

$$E_s = EF_j \times t_j \quad \text{Equation 350-2}$$

Where:

E_s = Annual natural gas volumetric emissions for pneumatic continuous high-bleed devices where gas is unmetered (Sm^3/y).

EF_j = Natural gas-drive pneumatic device (or equivalent device), j , bleed rate volume in Table 350-6 or in the CEPEI Methodology Manual ($\text{Sm}^3/\text{h}/\text{device}$).

t_j = Total time that the pneumatic device, j , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

The EF_j parameter may be calculated using Equation 350-2a:

$$EF_j = m \times SP_j \quad \text{Equation 350-2a}$$

Where:

m = the supply pressure coefficient in Table 350-6

SP_j = the supply pressure (kPa) of controller j

- (iii) If the device or equivalent device, is not listed in Table 350-6 or the CEPEI Methodology Manual, use the generic high bleed emission factor for all continuous high bleed controllers.
- (iv) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (a)(13) and (a)(14) of this section
- (2) Natural gas pneumatic pump venting. A person required to report pursuant to this quantification method shall calculate emissions from natural gas-driven pneumatic pump venting using the method specified in paragraph (a)(1) (i) above when the pump is metered.

For unmetered pumps use the methods specified in this section.

Natural gas-driven pneumatic pumps used in dehydrator systems do not have to report emissions under paragraph (2) of this section.

- (i) Calculate vented emissions for unmetered pneumatic pumps using Equation 350-3 or in the case of odourant injection pumps, the method specified in paragraph (C) below.

$$E_s = EF_j \times t_j \quad \text{Equation 350-3}$$

Where:

E_s = Annual natural gas volumetric emissions for high-bleed pneumatic devices where gas is unmetered (Sm^3/y).

EF_j = Natural gas-drive pneumatic device (or equivalent device), j bleed rate volume in Table 350-6 ($\text{Sm}^3/\text{h}/\text{device}$).

t_j = Total time that the pump, j, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h)

For pumps, except as noted in subparagraphs 1 and 2 below use the pump (or equivalent pump) specific emission factor provided in Table 350-6.

- (A) The EF_j parameter for pumps may be calculated using Equation 350-3a¹

$$EF_j = (g \times SP_j) + (n \times DP_j) = (p \times SPM_j) \quad \text{Equation 350-3a}$$

Where:

EF_j = bleed rate, the volume of natural gas bled per hour for pneumatic pump (or equivalent pump),j ($\text{Sm}^3\text{NG}/\text{h}$).

g = The supply pressure coefficient provided in Table 350-6

SP_j = The fuel supply pressure for the pump (or equivalent pump) j(kPa)
 n = The discharge pressure coefficient provided in Table 350-6

DP_j = The discharge pressure of pump (or equivalent pump) j(kPa)

SPM_j = the pump strokes per minute of pump “j” or equivalent pump.

P = The strokes per minute coefficient provided in Table 350-6

- (B) The EF_j parameter maybe be calculated using Equation

¹ If the pump is operating at less than five strokes per minute, this equation is not applicable and the mean bleed rate or volume of chemical equation should be used instead.

350-3b

$$EF_j = Q_j \times R_j \quad \text{Equation 350-3b}$$

Where:

Q_j = The volume rate of chemical injection for pump j (l/h)

R_j = The pump specific factor expressed as the volume of gas vented per litre of chemical injected. The factor takes into account fuel supply pressure, piston size, and discharge pressure based on chart published by the pump j manufacturer ($\text{Sm}^3\text{NG/L}$)

If the pump, or equivalent pump is not listed in Table 350-6 use the generic piston or diaphragm pump type emission factor, as appropriate

- (C) Calculate vented emissions from pneumatic pumps used for odourant injection using engineering estimates or emission factors as provided in the CEPEI Methodology Manual.
 - (ii) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (a)(13) and (a)(14) of this section.
- (3) Natural gas continuous low-bleed pneumatic device venting. A person required to report pursuant to this quantification method shall calculate emissions from natural gas continuous low-bleed pneumatic device venting as follows:
- (i) Calculate emissions from natural gas continuous low-bleed pneumatic device venting using Equation 350-4.

$$E_s = EF_j \times t_j \quad \text{Equation 350-4}$$

Where:

E_s = Annual natural gas volumetric emissions for continuous low-bleed bleed pneumatic devices (Sm^3/y).

EF_j = Population emission factor for natural gas-driven continuous low-bleed pneumatic device, j , as provided in Tables 350-1 and 350-2 or in the CEPEI Methodology Manual ($\text{Sm}^3/\text{h}/\text{device}$).

t_j = Total time that the pneumatic device, j , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

- (ii) Both CH_4 and CO_2 volumetric and mass emissions shall be

calculated from volumetric natural gas emissions using calculations in paragraphs (a)(13) and (a)(14) of this section.

(4) Natural gas intermittent (low and high) bleed pneumatic device venting.

A person required to report pursuant to this quantification method shall calculate emissions from natural gas intermittent (low and high) bleed pneumatic device venting as follows.

- (i) Calculate vented emissions for intermittent (low and high) bleed pneumatic devices used to maintain a process condition such as liquid level, pressure, delta pressure or temperature using Equation 350-5:

$$E_s = EF_j \times t_j \quad \text{Equation 350-5}$$

Where:

E_s = Annual natural gas volumetric emissions for intermittent (low and high) bleed pneumatic devices (Sm^3/y).

EF_j = Natural gas-drive pneumatic device (or equivalent device), j bleed rate volume in Table 350-6 (data within Table as revised from time to time and provided by the Regulation or in the CEPEI Methodology Manual) ($\text{Sm}^3/\text{h}/\text{device}$).

t_j = Total time that the pneumatic device, j , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

- (A) For individual intermittent pneumatic devices, except as noted below, use the device (or equivalent device) – specific emission factor provided in Table 350-6, or the EF_j parameter may be calculated using Equation 350-5a.

$$EF_j = m \times SP_j \quad \text{Equation 350-5a}$$

Where:

m = The supply pressure coefficient in Table 350-6

SP_j = The supply pressure (kPa) of the pneumatic device.

- (B) If the device (or equivalent device) is not present in Table 350-6 use the generic intermittent (high or low as appropriate) bleed factor in Table 350-1 or 350-2 or in the CEPEI Methodology Manual.

- (ii) A person required to report pursuant to this quantification method shall calculate vented emissions for intermittent (high) bleed pneumatic devices, used to drive compressor starters, using Equation 350-6:

$$E_s = EF_j \times t_j$$

Equation 350-6

Where:

E_s = Annual natural gas volumetric emissions for intermittent (high) bleed pneumatic devices (Sm^3/y).

EF_j = Emission factor for natural gas-driven pneumatic compressor starter, j , as provided by the manufacturer for the operating condition ($\text{Sm}^3/\text{min}/\text{device}$). If an emission factor is not available from the manufacturer, an emission factor for a similar compressor starter may be used in its place.

t_j = Total time that the pneumatic device, j , has been in service (i.e. the time that the gas flows to the device) through the reporting period (min).

Note: The volume of gas per start provided by the manufacturer may be used in place of the EF_j and t_j variables.

- (iii) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (a)(13) and (a)(14) of this section.
- (5) **Blowdown vent stacks.** A person required to report pursuant to this quantification method shall calculate blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non GHG gases) as follows:
- (i) Calculate the total physical volume (including, but not limited to, pipes, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.
 - (ii) If the total physical volume between isolation valves is greater than or equal to 1.42 m^3 , retain logs of the number of blowdowns for each equipment system (including, but not limited to pipes, compressors and vessels). Physical volumes smaller than 1.42 m^3 are exempt from reporting under paragraph (iii) below.
 - (iii) Calculate the venting emissions for each equipment system j using Equation 350-7 of this section:

$$E = V_j \left[\frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a) P_s Z_a} \right] \quad \text{Equation 350-7}$$

Where:

E_s = Natural gas venting volumetric emissions from blowdown of equipment system (Sm^3).

V_j = Total physical volume of blowdown equipment chambers (including, but not limited to, pipes, compressors and vessels) between isolation valves for the equipment system (m^3).

T_s = Temperature at standard conditions ($^{\circ}\text{C}$).

T_a = Temperature at actual conditions in the equipment system ($^{\circ}\text{C}$).

P_s = Absolute pressure at standard conditions (kPa).

$P_{a,1}$ = Absolute pressure at actual conditions in the equipment system (kPa) prior to depressurization.

$P_{a,2}$ = Absolute pressure at actual conditions in the equipment system after depressurization; 0 if equipment is purged using non-GHG gases (kPa).

Z_a = Compressibility factor at actual conditions for natural gas. Use a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

- (iv) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (a)(13) and (a)(14) of this section.
 - (v) Blowdowns that are directed to flares use the Flare stacks calculation method under (a)(7) rather than the Blowdown vent stacks calculation method under this paragraph.
- (6) **Damage Events.** A person required to report pursuant to this quantification method shall calculate fugitive emissions from damage events as follows:
- (i) For Transmission (ON.350) systems only. Use company gas release data used for regulatory purposes if available. If this data is not available, then for each dig-in incident (i.e., line hit) which results in gas release $\geq 1.416 \text{ Sm}^3$, calculate volumetric flow rate

prior to pipeline isolation for both catastrophic pipeline ruptures and pipeline puncture incidents using the appropriate methodology below.

(A) For catastrophic pipeline ruptures where the pipeline is severed use the following methodology:

$$Q_{\square} = \frac{3.6 \times 10^6 \times A}{\rho_s} \sqrt{\frac{K \times MW}{1000 \times R \times (273.15 + T_a)}} \times \frac{P_a \times M}{\left(1 + \frac{K-1}{2} M^2\right)^{\frac{K+1}{2(K-1)}}}$$

Equation 350-8

$$M = \sqrt{\frac{2 \left[\left(\frac{P_a}{P_e}\right)^{\frac{K-1}{K}} - 1 \right]}{K-1}}, \text{ (for } M \leq 1 \text{)}$$

Equation 350-9

Where:

M = 1, (for all other cases)

Q = natural gas venting volumetric flow rate (Sm³/h)

A = cross-sectional flow area of the pipe (m², A = πD²/4,000,000)

D = inside diameter of the pipe (mm)

K = specific heat ratio of the gas (dimensionless – 1.299 for methane)

M = Mach number of the flow

MW = molecular weight of the gas (kg/mole, 16.043 kg/mole for methane)

P_e = pressure at the damage point (local atmospheric pressure, kPa)

P_a = pressure inside the pipe at supply (kPa) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.

R = universal gas constant (8.3145 kPa·m³/kmol/K)

T_a = temperature inside pipe at the supply (°C)

ρ_s = gas density at standard conditions (kg/m^3) (0.6785 kg/m^3 for CH_4)

(B) For pipeline punctures where $(P_{Atm}/P_a) \geq (P_{Atm}/P_a)_{choked}$, use the following methodology, either individually per puncture, or in aggregate (using weighted averages) for multiple punctures of pipes of a given pressure and pipe type.

$$Q_s = \frac{A_e}{\rho_s} \sqrt{\frac{2000 \cdot K}{K - 1} P_a \rho_a \left[\left(\frac{P_{Atm}}{P_a} \right)^{2/K} - \left(\frac{P_{Atm}}{P_a} \right)^{(K+1)/K} \right]}$$

Equation 350-10

And:

$$\left(\frac{P_{Atm}}{P_a} \right)_{choked} = \left(\frac{2}{K+1} \right)^{K/(K-1)} = 0.546 \text{ (for methane)}$$

Equation 350-11

Where:

Q_s = natural gas venting volumetric flow rate (Sm^3/h)

A_e = size of the hole in the pipe (as either measured or estimated using engineering estimation techniques) (m^2)

ρ_s = gas density at standard conditions (kg/m^3) (0.6785 kg/m^3 for CH_4)

K = specific heat ratio of the gas (dimensionless – 1.299 for methane)

P_a = pressure inside the pipe (as either measured or estimated using engineering estimation techniques) at the puncture location (kPa)

ρ_a = gas density inside the pipe at the puncture location (kg/m^3)

P_{Atm} = atmospheric pressure outside the pipe (kPa)

MW = molecular weight of the natural gas (16.043 for methane)

$(P_{Atm}/P_a)_{choked} = 0.546$ - upper limit for choked flow

- (C) For pipeline punctures where $(P_{Atm}/P_a) < (P_{Atm}/P_a)_{choked}$, the person shall use the equations in section 6 (i) (A) above, with the value of A being set to the size of the hole rather than the cross-sectional flow area of the pipe.
- (D) Calculate volumetric natural gas emissions by multiplying Q or Q_s for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.
- (E) Calculate both CH₄ and CO₂ mass emissions from volumetric natural gas emissions using the calculation in paragraphs (a)(13) and (a)(14) of this section.
- (ii) For Distribution systems only: Use emission factors and quantification methods in the CEPEI Methodology Manual.
- (7) Flare stacks. A person required to report pursuant to this quantification method shall calculate CO₂, CH₄, and N₂O emissions from a flare stack as follows:
- (i) If there is a continuous flow measurement device on the flare, measured flow volumes can be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or use engineering calculations based on process knowledge, company records, and best available data.
- (ii) If there is a continuous gas composition analyzer on the gas stream to the flare, these compositions shall be used in calculating emissions. If there is no continuous gas composition analyzer on the gas stream to the flare, use the gas compositions for each stream of hydrocarbons going to the flare.
- (iii) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.
- (iv) Calculate GHG volumetric emissions at actual conditions using Equations 350-12, 350-13, 350-14, and 350-15 of this section.

$$E_{s,CH_4}(noncombusted) = Q_s \times (1 - \eta) \times Y_{CH_4} \quad \text{Equation 350-12}$$

$$E_{s,CO_2}(noncombusted) = Q_s \times Y_{CO_2} \quad \text{Equation 350-13}$$

$$E_{s,CO_2}(combusted) = \sum_i \eta \times Q_s \times Y_i \times n_i \quad \text{Equation 350-14}$$

$$E_{s,CO_2}(total) = E_{s,CO_2}(combusted) + E_{s,CO_2}(noncombusted) \quad \text{Equation 350-15}$$

Where:

E_{s,CH_4} (noncombusted) = Contribution of annual noncombusted volumetric CH_4 emissions from flare stack (Sm^3).

E_{s,CO_2} (noncombusted) = Contribution of annual volumetric CO_2 emissions from CO_2 in the inlet gas passing through the flare noncombusted (Sm^3).

E_{s,CO_2} (combusted) = Contribution of annual volumetric CO_2 emissions from combustion from flare stack (Sm^3).

Q_s = Volume of natural gas sent to flare during the year (Sm^3).

η = Fraction of natural gas combusted by flare (default combustion efficiency is 0.98). For gas sent to an unlit flare, η is zero.

Y_{CH_4} = Mole fraction of CH_4 in gas to the flare.

Y_{CO_2} = Mole fraction of CO_2 in gas to the flare.

Y_i = Mole fraction of hydrocarbon constituents i (i.e., methane, ethane, propane, butane, pentanes, hexane, and pentane plus) in natural gas to the flare.

n_i = Number of carbon atoms in the hydrocarbon constituent i ; (e.g., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, 5 for pentanes, 6 for hexanes and 7 for pentanes plus) in natural gas to the flare.

(v) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions as determined in paragraph (7)(iv) of this section using the calculation in paragraph (a)(14) of this section.

(vi) Calculate N_2O emissions using Equation 350-16.

$$E_{N_2O} = Q_s \times HHV \times EF \times 0.001 \quad \text{Equation 350-16}$$

Where:

E_{N_2O} = Annual N_2O mass emissions from flaring (tonnes/y).

Q_s = Volume of gas combusted by the flare in the reporting period (Sm^3/y).

HHV = High heat value of the flared gas from paragraph (7)(ii)

EF = N_2O emission factor. Use 9.52×10^{-5} kg N_2O /GJ.

0,001 = Conversion factor from kilograms to tonnes.

- (vii) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in this section. Where gas to be flared is manifolded from multiple sources in ON.353 to a common flare, report all flaring emissions under ON.355(a)(7).
- (8) Centrifugal compressor venting. A person required to report pursuant to this quantification method shall calculate emissions from all centrifugal compressor vents as follows. Where venting emissions are sent to a common flare, calculate emissions using ON.353(a)(7).

Dry seal and wet seal centrifugal compressors can enter the following operating modes: “operating, pressurized”, “stand-by, pressurized” or “not-operating, depressurized”.

- (i) The person shall calculate CO₂, and CH₄, and N₂O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing vent lines, but excluding dry deal gas vent lines) for all compressors using a temporary or permanent flow measurement meter such as, but not limited to, portable utility grade meter (bellows meter), high-flow sampler or vane anemometer according to methods set forth in ON.354(a)(2) and (4).
- (ii) Estimate annual emissions using flow meter measurement using Equation 350-17 of this section.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF) \quad \text{Equation 350-17}$$

Where:

$E_{s,i}$ = Annual GHG i (either CH₄ or CO₂) volumetric emissions from all compressor venting modes (Sm³).

$Q_{s,m}$ = Measured volumetric gas emissions during operating mode m described in paragraph (8)(v) of this section (Sm³/h).

t_m = Total time the compressor is in operational mode m during the calendar year (h)

Y_i = Annual average mole fraction of GHG i in the degassing vent gas; use the appropriate gas compositions in paragraph (13)(ii) of this section.

CF = Fraction of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of vent gas that is directed to the fuel gas system.

m = The operational mode of a centrifugal compressor.

- (iii) To ensure that emissions for modes not found during the annual measurement are included in reported estimates, Equation 350-

17a shall be used to calculate total emissions

$$E_{S,i,c} = E_{S,i} + E_{m,nf} \quad \text{Equation 350-17a}$$

Where:

$E_{S,i,c}$ = Total estimate of emissions from all operating modes

$E_{S,i}$ = Output of Equation 350-17

$E_{m,nf}$ = Estimate of emissions for the modes not found during the annual measurement as calculated from emissions for mode not found for the compressor during previous years and prorated for the time in the year for the mode not found. If the mode not found did not occur in previous years, estimates from a similar compressor or manufacturer emission factors may be used, in order of preference.

- (iv) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the $Q_{s,m}$ variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year in place of metered gas volumes if an applicable meter is not present on the compressor. Alternatively, a source-specific emissions factor can be established by measuring the emissions from relevant sources during each operational mode.
- (v) Conduct an annual measurement for each compressor in the mode in which it is found (see below) during the annual measurement starting in the year 2018. As applicable, measure emissions from (including emissions manifolded to common vents) degassing vents, unit isolation-valve vents and blowdown-valve vents. If there is a safety risk that cannot be (reasonably) mitigated with measuring emissions from a specific vent line, the person may use an emission factor approach instead. Winter safety is not a valid safety risk unless the site can only be accessed during the winter. The operational modes are:
 - (A) Operating pressurized mode, blowdown vent leakage through the blowdown vent stack and wet seal oil degassing vent (if applicable); for wet seal and dry seal compressors.
 - (B) Standby pressurized mode.
 - (C) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack.
 - (C.1) Notwithstanding paragraph (v) above, for the not operating, depressurized mode, each compressor shall be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement (if the

compressor enters the not operating depressurized mode during normal service (i.e. excluding maintenance).

(C.2) A compressor is exempt from this requirement to measure in the not operating, depressurized mode if,

- During normal service, it remains pressurized and the only time the unit is depressurized is for maintenance or as a result of an emergency shutdown; or
- The compressor has blind flanges in place.

(C.3) If a compressor unit is exempt from the 3 year measurement requirement in C.1, use Equation 350-17a to calculate emissions for that unit for the not-operating depressurized mode.

- (vi) Calculate both CH₄ and CO₂ mass emissions from volumetric CH₄ and CO₂ emissions as determined in paragraphs (8)(i) through (iv) of this section using calculations in paragraph (a)(14) of this section.
- (vii) Calculate emissions from degassing vent vapours to flares as follows:
- (A) Use the degassing vent vapour volume and gas composition as determined in paragraphs (8)(i) through (iv) of this section.
- (B) Use the calculation methodology of flare stacks in paragraph (7) of this section to determine degassing vent vapour emissions from the flare.
- (viii) Emissions from centrifugal compressor dry seal gas vent lines may be determined following the procedures set forth in paragraphs (a)(5) and (a)(7), engineering estimates or other industry standard method, as appropriate.
- (9) Reciprocating compressor venting. A person required to report pursuant to this quantification method shall calculate annual CH₄ and CO₂ emissions from all reciprocating compressor vents as follows.

Where venting emissions are sent to a common flare, calculate emissions using ON.353(7).

A reciprocating compressor's operational modes include "operating, pressurized", "standby, pressurized mode" and "not operating, depressurized"

- (i) Calculate annual emissions using the flow measurement in (9)(iii) or (iv) below and Equation 350-18.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i(1 - CF) \quad \text{Equation 350-18}$$

Where:

$E_{s,i}$ = Annual volumetric emissions of GHG i (either CH₄ or CO₂) from all compressor venting modes (Sm³/y).

$Q_{s,m}$ = Measured volumetric gas emissions during operating mode m described in paragraph (9)(v) (Sm³/h).

t_m = Total time the compressor is in operational mode m during the calendar year (h).

Y_i = Annual average mole fraction of GHG i in the vent gas; use the appropriate gas compositions in paragraph (13)(ii) of this section.

CF = Fraction of reciprocating compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the vent gas that is directed to the fuel gas system.

m = The operational mode of a reciprocating compressor.

- (ii) Calculate total emissions, including modes not found during the annual measurement, using Equation 350-18a.

$$E_{s,i,c} = E_{s,i} + E_{m,nf} \quad \text{Equation 350-18a}$$

Where:

$E_{s,i,c}$ = Total estimate of emissions from all operating modes

$E_{s,i}$ = Output of Equation 350-18

$E_{m,nf}$ = Estimate of emissions for the modes not found during the annual measurement as calculated from emissions for operational mode not found for the compressor during previous years and prorated for the time in the year for the mode not found. If the operational mode not found did not occur in previous years, estimates from a similar compressor or manufacturer emission factors may be used.

- (iii) If the reciprocating rod packing and blowdown vent is connected to an open-ended vent line then use one of the following two methods to calculate emissions.
- (A) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or High-flow Sampler according to methods set forth in ON.354(a)(3) and (4).
- (B) Use a temporary meter such as a portable utility grade meter (bellows meter) a vane anemometer or a permanent

meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in ON.354(a)(2). If you do not have a permanent flow meter, you may install a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open-ended vents, such as unit isolation valves on not-operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in ON.354(a).

- (iv) If the rod packing case is not equipped with a vent line, use the following method to estimate emissions:
 - (A) Use the methods described in ON.354(a)(1) to conduct a progressive leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.
 - (B) Measure emissions using a High-flow Sampler, or calibrated bag, or appropriate meter according to methods set forth in ON.354(a)(2), (3), or (4).
- (v) Conduct an annual measurement for each compressor in the operational mode in which it is found during the annual measurement starting in 2018. Measure emissions from (including emissions manifolded to common vents) reciprocating rod-packing vents, unit isolation-valve vents, and blowdown-valve vents. If there is a safety risk that cannot be reasonably mitigated with measuring emissions from a specific vent line, the Person may use an emission factor approach instead. Given that there is not a requirement to measure in the winter months, winter safety is not an applicable safety risk unless the site is only accessible in the winter.

The operational modes are:

- (A) Operating pressurized mode, blowdown vent leakage through the blowdown vent stack and reciprocating rod packing emissions.
- (B) Standby pressurized mode.
- (C) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack.
 - (C.1) Notwithstanding paragraph (v) above, for the not operating, depressurized mode, each compressor shall be

measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement (if the compressor enters the not operating depressurized mode during normal service (i.e. excluding maintenance)).

(C.2) A compressor is exempt from this requirement to measure in the not operating, depressurized mode if,

- During normal service, it remains pressurized and the only time the unit is depressurized is for maintenance or as a result of an emergency shutdown; or
- The compressor has blind flanges in place.

(C.3) If a compressor unit is exempt from the 3 year measurement requirement identified in the first paragraph, use Equation 350-18a in paragraph (9)(ii) to calculate emissions for that unit for the not-operating depressurized mode.

- (vi) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (a)(13) and (a)(14) of this section.
- (vii) Adjust the emissions from reciprocating compressor vent vapors as follows if they are sent to a vapor recovery system.
 - (A) Adjust the emissions estimated in paragraphs (9)(i) of this section for the emissions recovered using a vapor recovery system as determined by using engineering estimate based on best available data, equipment or design specifications, manufacturer's data, operating data.
 - (B) An engineering estimate approach based on similar equipment specifications and operating conditions or manufacturer's data may be used to determine the Q_{s,m} variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year.
- (10) Leak detection and leaker emission factors. A person required to report pursuant to this calculation method shall use sampling methods (described in ON.354(a)) to conduct a leak detection survey of fugitive equipment leaks. All sources listed in ON.352(b)(2), (c)(2) (excluding the wellheads and underground piping that connect to the compression units), (d)(2), and (e)(2) where total emissions for the site is 10,000 tonnes CO₂e or greater shall use this calculation method. If the total emissions from the site are less than 10,000 tonnes CO₂e, the person may use this calculation method or the calculation method in ON.353(a)(11).

The calculation in paragraph (10) applies to emissions sources in streams with gas containing greater than 10 percent CH₄ plus CO₂ by weight. Emissions sources in streams with gas containing less than 10 percent CH₄ plus CO₂ by weight need to be reported instead under paragraph (15) of this section.

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate equipment leak emissions per source using Equation 350-19 (for volumetric emission factor [Sm³/h/component]) or Equation 350-20 (for mass emission factors [t/h/component]) of this section, as appropriate, for each source with fugitive equipment leaks.

$$E_i = EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001 \quad \text{Equation 350-19}$$

$$E_{s,j} = EF_s \times Y_i \times t \quad \text{Equation 350-20}$$

Where:

$E_{s,i}$ or $E_{s,j}$ = Annual total mass emissions of GHG_i (CH₄ or CO₂) from each fugitive equipment leak source (tonnes/year).

EF_s = Leaker emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section or facility/company-specific emission factors* used in place of Tables 350-1 to 350-5 (Sm³/component/year for Equation 350-19 and tonnes/component/year for Equation 350-20).

Y_i = For volumetric emissions in Equation 350-19, use 0.975 for CH₄ for natural gas transmission, compression and underground natural gas storage and 1.1×10^{-2} for CO₂; for LNG storage and LNG import and export equipment, Y_i equals 1 for CH₄ and 0 for CO₂; or use the experimentally determined gas composition for CO₂ and CH₄. For mass emissions in Equation 350-20, use mass fractions of CH₄ and CO₂ from each unit of a distribution or transmission company within a jurisdiction that has similar gas composition or the CEPEI Methodology Manual.

t = Total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking from the start of the year or the date of the last survey until the leak was repaired and then zero for the remainder of the interval between leak surveys. If the leak was not repaired, assume the component was leaking for the entire year or the entire leak survey interval. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the last survey during which it was determined to be not leaking, or the beginning of the calendar year. For the last leak detection survey in the calendar year or leak

survey interval, assume that all leaking components continue to leak until the end of the calendar year or leak survey interval and until the component was repaired and then zero until the end of the year or leak survey interval.

$\rho_{s,i}$ = Density of GHG i (1.861 kg/m³ for CO₂ and 0.678 kg/m³ for CH₄ at standard conditions of 15 °C and 1 atmosphere).

0.001 = Conversion factor from kilograms to tonnes.

** person may use component-specific emission factors quantified using ON.354(a)(3) or (a)(4) during leak detection surveys.*

- (i) Onshore natural gas transmission compression stations shall use the appropriate default leaker emission factors listed in Table 350-1 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open ended lines.
 - (ii) Underground natural gas storage stations shall use the appropriate default leaker emission factors listed in Table 350-2 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open-ended lines.
 - (iii) LNG storage stations shall use the appropriate default leaker emission factors listed in Table 350-3 of this section for fugitive equipment leaks detected from valves, pump seals, connectors, and other equipment.
 - (iv) LNG import and export stations shall use the appropriate default leaker emission factors listed in Table 350-4 of this section for fugitive equipment leaks detected from valves; pump seals; connectors; and other.
- (11) Population count and emission factors. A person required to report pursuant to this quantification method shall use the following calculation for sites with total emissions that are less than 10,000 tonnes per year, for sources listed in ON.352 (b)(2), (c)(2), (d)(2), and (e)(2).

A person shall also use the following calculation method for sources listed in ON.352 (b)(6), (f)(1), f(2), f(3) and (f)(4).

The calculation in paragraph (11) applies to emissions sources on streams with gas containing greater than 10 percent CH₄ plus CO₂ by weight. Emissions sources in streams with gas containing less than 10 percent CH₄ plus CO₂ by weight do not need to be reported.

Emission sources at which a leak detection survey has been conducted and reported under ON.353(a)(10) (either voluntarily or required under Section 353(a)(10)) are exempt from the requirements under ON.353(a)(11).

Calculate emissions from all sources listed in this paragraph using Equation 350-21 (for volumetric emission factor [$\text{m}^3/\text{h}/\text{component}$]) or Equation 350-22 (for mass emission factors [$\text{kg}/\text{h}/\text{component}$]) of this section, as appropriate.

$$E_i = N \times EF_s \times Y_i \times t \times p_{s,i} \times 0.001 \quad \text{Equation 350-21}$$

$$E_i = N \times EF_s \times X_i \times t \times 0.001 \quad \text{Equation 350-22}$$

Where:

- E_i = Annual total mass emissions of GHG i (CH_4 or CO_2) from each fugitive source (tonnes/year).
- N = Total number of this type of emission source at the site. The average component counts by major equipment pieces from the CEPEI Methodology Manual, other relevant Canadian Gas Association (CGA), or Canadian Association of Petroleum Producers documentation, may be used for 2017 and 2018 calendar year emissions as appropriate for operations and required by (i) through (v), below. For 2019 calendar year emissions and onwards component counts for individual sites are to be used except for sources listed in ON.352(b)(2),(c)(2),(d)(2), and (e)(2). If station or company-specific major equipment count data that meet or exceed the quality of the relevant default count data are available, they shall be used in its place. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years. For sources listed in ON.352 (f)(1), the average component counts used in 2017 and 2018 may also be used for 2019 onwards.
- EF_s = Population emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section ($\text{Sm}^3/\text{component}/\text{hour}$ for Equation 350-21 and tonnes/component/hour for Equation 350-22). Direction on the use of Tables 350-1 through 350-5, provided prior to the tables, shall be followed and indicates that if the person's specific emission factors are available the person's specific emission factors shall be used*.
- Y_i = For volumetric emissions in Equation 350-21, use 0.975 for CH_4 for natural gas transmission, compression and underground natural gas storage and 1.1×10^{-2} for CO_2 ; for LNG storage and LNG import and export equipment, Y_i equals 1 for CH_4 and 0 for CO_2 ; and for natural gas distribution, Y_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2 or use the experimentally determined gas composition for CO_2 and CH_4 .

- X_i = For mass emissions in Equation 350-22, use mass fractions of CH_4 and CO_2 from the person's specific data or the CEPEI Methodology Manual.
- t = Total time the specific source associated with the fugitive equipment leak was operational in the calendar year (hours).
- $\rho_{s,i}$ = Density of GHG i (1.861 kg/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at standard conditions of 15°C and 1 atmosphere).
- 0.001 = Conversion factor from kilograms to tonnes.

*the person's specific emission factors may be developed based on leak rates quantified, following ON.354(3) or (4), during leak detection surveys or those emission factors calculated for the purposes of ON.356 – Directions for the use of Tables 350-1 to 350-5.

- (i) Transmission stations shall use the appropriate default population emission factors listed in Table 350-1 of this section for fugitive equipment leaks from connectors, valves, pressure relief valves, and open-ended lines.
- (ii) Underground natural gas storage stations shall use the appropriate default population emission factors listed in Table 350-2 of this section for fugitive equipment leaks from connectors, valves, pressure relief valves, and open-ended lines.
- (iii) LNG storage stations shall use the appropriate default population emission factors listed in Table 350-3 of this section for fugitive equipment leaks from vapour recovery compressors.(except storage at LNG import and export facilities which is covered in ON.353(a)(11)(iv)).
- (iv) LNG import and export stations shall use the appropriate default population emission factor listed in Table 350-4 of this section for fugitive equipment leaks from vapour recovery compressors.
- (v) Natural gas distribution facilities shall use the appropriate emission factors as follows.
 - (A) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table 350-5 of this section.
 - (B) Above grade meter-regulating stations and all other above-grade stations including customer meters shall be estimated using the CEPEI Methodology Manual methods and component emission factors.
 - (C) For buried pipeline-main and service line leaks, Equations 350-21 and 350- 22 and their inputs may be modified as

outlined in the CEPEI Methodology Manual.

(12) Volumetric emissions. A person required to report pursuant to this quantification method shall calculate volumetric emissions at standard conditions as specified in paragraphs (12)(i) or (12)(ii), with actual pressure and temperature of this section determined by engineering estimate based on best available data unless otherwise specified.

- (i) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure to standard temperature and pressure (15 °C and 1 atmosphere) using Equation 350-23 of this section.

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s} \quad \text{Equation 350-23}$$

Where:

E_s = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (Sm^3).

E_a = Natural gas volumetric emissions at actual conditions (m^3).

T_s = Temperature at standard conditions (15C °).

T_a = Temperature at actual emission conditions (°C).

P_s = Absolute pressure at standard conditions (101.325 kPa).

P_a = Absolute pressure at actual conditions (kPa).

- (ii) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation 350-24 this section.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s} \quad \text{Equation 350-24}$$

Where:

$E_{s,i}$ = GHG_i volumetric emissions at standard temperature and pressure (STP) conditions (Sm^3).

$E_{a,i}$ = GHG_i volumetric emissions at actual conditions (m^3).

T_s = Temperature at standard conditions (15°C).

T_a = Temperature at actual emission conditions (°C).

P_s = Absolute pressure at standard conditions (101.325 kPa).

P_a = Absolute pressure at actual conditions (kPa).

(13) GHG volumetric emissions. A person required to report pursuant to this quantification method shall calculate the volumetric emission using the following calculations.

If the GHG volumetric emissions at actual conditions are known, follow the method in paragraph (13)(ii) to calculate their emissions at standard conditions.

If the GHG volumetric emissions are not yet known, use engineering estimate based on best available data unless otherwise specified and the methods below to calculate GHG volumetric emissions at standard conditions as specified in paragraphs (13)(i) and (ii) of this section determined by.

- (i) Estimate CH₄ and CO₂ emissions from natural gas emissions using Equation 350-25 of this section

$$E_{s,i} = E_s \times Y_i \qquad \text{Equation 350-25}$$

Where:

$E_{s,i}$ = GHG_i (either CH₄ or CO₂) volumetric emissions at standard conditions.

E_s = Natural gas volumetric emissions at standard conditions.

Y_i = Mole fraction of GHG_i in the natural gas.

- (ii) For Equation 350-25 of this section, the mole fraction, Y_i , shall be the annual average mole fraction for each unit of a natural gas distribution, natural gas transmission, LNG storage, LNG import or export, or underground natural gas storage company within a jurisdiction that has similar gas composition as sampled within the current (required if available) or previous (if current data not available) reporting period, using the methods set forth in ON.354(a(2)), and specified in paragraphs below.
- (A) GHG mole fraction in transmission pipeline natural gas that passes through the onshore natural gas transmission compression stations.
 - (B) GHG mole fraction in natural gas stored in underground natural gas storage.
 - (C) GHG mole fraction in natural gas stored in LNG storage station.
 - (D) GHG mole fraction in natural gas stored in LNG import and export station.
 - (E) GHG mole fraction in local distribution pipeline natural gas that passes through the natural gas distribution system.

(14) GHG mass emissions. A person required to report pursuant to this

quantification method shall Calculate GHG mass emissions in tonnes of carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 350-26 of this section.

$$E_i = E_{s,i} \times \rho_{s,i} \times 0.001 \quad \text{Equation 350-26}$$

Where:

- E_i = GHG_i (either CH₄, CO₂, or N₂O) mass emissions (tonnes CO₂e).
 $E_{s,i}$ = GHG_i (either CH₄, CO₂ or N₂O) volumetric emissions at standard conditions (Sm³).
 $\rho_{s,i}$ = Density of GHG *i* (1.861 kg/m³ for CO₂ and 0.678 kg/m³ for CH₄ at standard conditions of T_s = 15°C and P_s = 101.325 kPa).

$$\rho_{s,i} = \frac{P_s \times MW_i}{R_u \times (T_s + 273.15)}$$

MW_i = Molecular weight for GHG_i (kg/kmole).

R_u = Universal gas constant (8.31434 kJ/kmole K)

0.001 = Conversion factor from kilograms to tonnes

(15) Other venting or fugitive emissions. A person required to report pursuant to this quantification method shall determine all venting or fugitive emissions not covered by quantification methods in ON.353 using methodologies consistent with those presented in the CEPEI Methodology Manual, or in other relevant documents published by the Canadian Gas Association or any other industry association.

(16) Transmission storage tanks. A person required to report pursuant to this quantification method shall by 2019 determine emissions from transmissions storage tanks using the following.

For condensate storage tanks, either water or hydrocarbon, without vapour recovery or thermal control devices in onshore natural gas transmission compression facilities the operator shall calculate CH₄, CO₂ and N₂O (when flared) annual emissions from compressor scrubber dump valve leakage as follows.

- (i) Monitor the tank vapour vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in ON.354(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or High-flow Sampler according to methods in ON.354(a)(2) through (4) for a duration of 5 minutes. Or the

person may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in ON.354(a)(1)(D).

- (ii) If the tank vapours are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods.
 - (A) Use a meter, such as a turbine meter, calibrated bag, or High-flow Sampler to estimate tank vapour volumes according to methods set forth in ON.354(a)(2) through (4). If the vent is directly measured for five minutes under paragraph (16)(1) of this section to detect continuous leakage, this serves as the measurement.
 - (B) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in ON.354(a).
 - (C) Use the appropriate gas composition in paragraph (13) of this section.
- (iii) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired. If the leak is not repaired, assume the dump valve is leaking for the entire year or until the dump valve is repaired.
- (iv) Calculate annual emissions from storage tanks to flares as follows:
 - (A) Use the storage tank emissions volume and gas composition as determined in paragraphs (13)(i) through (13)(iii) of this section.
 - (B) Use the calculation methodology of flare stacks in paragraph (7) of this section to determine storage tank emissions sent to a flare.

ON.354 Sampling, Analysis, and Measurement Requirements

- (a) A person required to report pursuant to this quantification method shall ensure instruments used for sampling, analysis and measurement shall be operated and calibrated according to regulatory, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement shall be conducted only by, or under the direct supervision of personnel or individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

- (1) A person required to report pursuant to this quantification method shall undertake the following Leak Detection program
 - (i) If a documented leak detection or integrity management standard or requirement that is required by Ontario or federal legislation or regulation (e.g., CSA Z662-07 Oil & Gas Pipeline Systems) or by a standard or method from Canadian Gas Association, the documented standard or requirement shall be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein. A maximum of 36 months is allowed between leak detection surveys.
 - (ii) If there is no such legal requirement (as specified in the previous paragraph), then representative sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in ON.353 (a)(10), as applicable. Representative sampling means establishing the most valid or credible sample of leaks that accurately characterizes the number of fugitive equipment leaks required per sample interval, under operating conditions. A baseline representative sample of leaks shall be established under normal operating conditions for the 2017 calendar years or upon acquisition of previously operated equipment or within the first year of operation of newly constructed or acquired equipment. Subsequent representative sampling shall be based on random or stratified sampling, modeling, detection or measurement of leaks under normal operating conditions. After establishing the baseline representative sample of leaks per sample interval, a maximum of 36 months is allowed between sampling. The interval is determined based on whether there are leaks. If a leak is found and immediately repaired, the existing schedule may be maintained. If a leak is found and not repaired the maximum interval between sampling is 18 months and the leak shall be monitored (and optionally measured) on a regular basis until repaired. If the equipment is replaced the maximum sampling interval is 18 months until a baseline representative sample of leaks has been established under normal operating conditions.

Leak detection for fugitive equipment leaks shall be performed for all identified equipment in operation or on standby mode using one of the following.

 - (A) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and
 - (2) Alternative work practice for monitoring equipment leaks.

In addition, the optical gas imaging instrument shall be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument shall comply with the following requirements:

- (A.1) Provide the person with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument inspection described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.
 - (A.2) Provide a date and time stamp for video records of every monitoring event.
 - (B) Bubble tests. Uses soap or other types of bubbles on equipment to visually detect the leak of gases from the equipment.
 - (C) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions
 - (D) Other methods as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions (as amended from time to time) may be used as necessary for operational circumstances. Other methods based on an engineering assessment may also be used as necessary for operational circumstances provided there is documentation on the method used, results of tests, and the method's reliability and accuracy is maintained and updated at regular intervals.
- (2) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use appropriate QA/QC procedures, including measurement methods, maintenance practices, and calibration methods by 2018 and in each subsequent calendar year according to an appropriate standard published by a consensus standards organization. If a consensus based standard is not available, industry standard practices such as manufacturer instructions shall be used.
- (3) Use calibrated bags (also known as vent bags) only where the emissions are at or near atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the

maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed 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. If the bag inflates in less than one second, assume one second inflation time.
 - (ii) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.
 - (iii) Correct the natural gas volumetric emissions to standard conditions using the calculations in ON.353(a)(12).
 - (iv) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in ON.353(a)(13) and (14).
- (4) Use a high-flow sampler to measure emissions within the capacity of the instrument.
- (i) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH₄ by using calibrated gas samples and by following manufacturer's instructions for calibration.
 - (ii) Conduct measurements, using equipment manufacturer operating procedures and relevant measurement methodologies, by positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.
 - (iii) If the High-flow Sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.
 - (iv) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in ON.353(a)(13) and (14).

ON.355 Procedures for Estimating Missing Data

- (a) A person required to report pursuant to this quantification method shall retain a complete record of all estimated and/or measured parameters used in the GHG emissions calculations.
- (b) If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources shall be repeated as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the calendar year,

until valid data for reporting is obtained.

- (c) Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation.
- (d) Where missing data procedures are used for the previous year, at least 30 days shall separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection.
- (e) For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the person may use best available data for use in emissions determinations. The person shall record and report the basis for the best available data in these cases.

ON.356 Tables

Directions for the use of Tables 350-1 to 350-5:

- (a) For each component listed in the Tables 350-1 to 350-5 or otherwise required by the quantification method referencing Tables 350-1 and 350-2:
 - (1) If statistically valid company specific emission factors for a component type are available they shall be used. If statistically valid company specific emission factors can be reasonably developed using existing company leak detection data then they shall be used.
 - (2) If company specific emissions factors for a component type are not available, a person shall use statistically valid company specific emission factors, if they are available. If statistically valid company-specific emission factors can be reasonably developed using existing company leak detection data then they shall be used.
- (b) If statistically valid company-specific emission factors for a specific component are not available, emission factors in the default Tables 350-1 to 350-5 may be used,
 - (1) A person may use the default factors specified below, company specific emissions factors (if such emission factors are available).
- (c) If an emission factor required by the quantification method referencing Tables 350-1 through 350-5 is not provided in the tables, emission factors from the CEPEI Methodology Manual or U.S. EPA 40 CFR Part 98.230 Tables W-3 through W-7 (in order of preference), may be used (as converted for use in the relevant equation).
- (d) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information shall be kept by the person and provided to the jurisdiction or verifier upon request.
- (e) Updated emission factors can only be incorporated for reporting purposes at

the start of a reporting period and not during a calendar year.

- (f) All emission factors or data collection for emission factors shall be developed using the CEPEI Methodology Manual, or other methods if the CEPEI Methodology Manual methods are not available or applicable. Company-specific emission factors that have been developed using existing company leak detection data shall be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2020 reporting period, at the latest.

Table 350-1 –Default Emission Factors for Transmission

All Components, Natural Gas Service	Population Emission Factor^{1a} (tonnes/hr/component)	Leaker Emission Factor^{1b} (tonnes/hr/component)
Connector	4.471E-7	4.848E-5
Block valve	4.131E-6	1.275E-4
Control valve	1.650E-5	8.205E-5
Station or pressurized compressor blowdown valve	3.405E-3	5.691E-3
Pressure relief valve	1.620E-4	5.177E-4
Orifice meter	4.863E-5	2.076E-4
Other flow meter	9.942E-9	3.493E-7
Regulator	7.945E-6	1.125E-4
Open-ended line	9.183E-5	1.580E-4
Other Components, Natural Gas Service	Population Emission Factor (Sm³/hour/component)²	
Low-bleed pneumatic device vents	3.88 E-2	
High continuous bleed pneumatic device vents	2.605 E-1	
Intermittent high bleed pneumatic device vents	2.476 E-1	
Intermittent low bleed pneumatic device vents	6.65 E-2	
Diaphragm Pumps	1.0542 E-0	
Piston Pumps	5.917 E-1	

1. Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2012. As these emission factors are updated from time to time, the intention is to incorporate such updates here as well as permit use of the most recent values published.
 - a. Table 9, p50
 - b. Table 12, p80.
2. Prasino Final Pneumatic Field Sampling Report or Direct conversion of EF's in 2011 EPA Subpart W Table W (scf to SM³). *Source : US EPA, Mandatory Reporting of greenhouse Gases – Rules and Regulations, Subpart W Table 7, Dec 23, 2012.*

**Table 350-2
 Default Methane Emission Factors for Underground Storage***

Underground Storage	Emission Factor (Sm³/hour/component) Prasino Final Pneumatic Field Sampling Report* Direct conversion of EF's in EPA Subpart W Table* W-4 (scf to Sm³)
Leaker Emission Factors - Storage Station, Gas Service -Valve ¹	4.268 E-1
Leaker Emission Factors - Storage Station, Gas Service – Connector	1.60 E-1
Leaker Emission Factors - Storage Station, Gas Service - Open-ended line	4.967 E-1
Leaker Emission Factors - Storage Station, Gas Service - Pressure relief valve	1.140
Leaker Emission Factors - Storage Station, Gas Service - Meter	5.560 E-1
Population Emission Factors - Storage Wellheads, Gas Service – Connector	2.8 E-4
Population Emission Factors - Storage Wellheads, Gas Service – Valve	2.8 E-3
Population Emission Factors - Storage Wellheads, Gas Service - Pressure relief valve	4.8 E-3
Population Emission Factors - Storage Wellheads, Gas Service - Open-ended line	8.5 E-4
Population Emission Factors - Other Components, Gas Service - Low-bleed pneumatic device vents	3.88 E-2
Population Emission Factors - Other Components, Gas Service - High continuous bleed pneumatic device vents	2.605 E-1
Population Emission Factors - Other Components, Gas Service - Intermittent high bleed pneumatic device vents	2.476 E-1
Population Emission Factors - Other Components, Gas Service - Intermittent (low) bleed pneumatic device vents	56.65 E-12
Population Emission Factors - Other Components, Gas Service - Diaphragm Pumps	1.0542 E-0
Population Emission Factors - Other Components, Gas Service - Piston Pumps	5.917 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-4.

¹Valves include control valves, block valves and regulator valves

**Table 350-3
Default Methane Emission Factors For Liquefied Natural Gas (LNG) Storage***

LNG Storage	Emission Factor (Sm³/hour/component) Direct conversion of EF's in EPA Subpart W Table W-5 (scf to Sm³)
Leaker Emission Factors - LNG Storage Components, LNG Service - Valve	3.43 E-2
Leaker Emission Factors - LNG Storage Components, LNG Service - Pump seal	1.15 E-1
Leaker Emission Factors - LNG Storage Components, LNG Service - Connector	9.9 E-3
Leaker Emission Factors - LNG Storage Components, LNG Service - Other ¹	5.10 E-2
Population Emission Factors - LNG Storage Compressor, Gas Service - Vapour Recovery Compressor	1.20 E-1

¹The "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

* Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-5.

Table 350-4–Default Methane Emission Factors for LNG Terminals*

LNG Terminals	Emission Factor (Sm³/hour/component) Direct conversion of EF's in EPA Subpart W Table W-6 (scf to Sm³)
Leaker Emission Factors - LNG Terminals Components, LNG Service - Valve	3.43 E -2
Leaker Emission Factors - LNG Terminals Components, LNG Service - Pump seal	1.15 E-1
Leaker Emission Factors - LNG Terminals Components, LNG Service - Connector	9.9 E-3
Leaker Emission Factors - LNG Terminals Components, LNG Service - Other	5.10 E-2
Population Emission Factors - LNG Terminals Compressor, Gas Service - Vapour recovery compressor	1.20 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-6.

**Table 350-5
Default Emission Factors for Distribution**

	CEPEI	CEPEI ¹
Components	Population Emission Factor*^a (tonnes/hr/source)	Leaker Emission Factor*^b tonnes/hr/source
Connector	8.227E-8	6.875E-6 ^b
Block valve	5.607E-7	1.410E-5 ^b
Control valve	1.949E-5	7.881E-5 ^b
Pressure relief valve	3.944E-6	3.524E-5 ^b
Orifice meter	3.011E-6	8.091E-6 ^b
Other flow meters	7.777E-9	2.064E-7 ^b
Regulator	6.549E-7	2.849E-5 ^b
Open-ended line	6.077E-5	1.216E-4 ^b
Below Grade M&R Station Components, Natural Gas Service	Population Emission Factor (Sm³/hr/Station)	
Below grade M&R station, inlet pressure > 300 psig	3.681E-2 or value from CEPEI Manual	
Below grade M&R station, inlet pressure 100 to 300 psig	5.663E-3 or value from CEPEI Manual	
Below grade M&R station, inlet pressure < 100 psig	2.832E-3 or value from CEPEI Manual	
Distribution Mains, Natural Gas Service	Population Emission Factor (Sm³/hr/km)	
Unprotected steel	or 2.427E-1 or value from CEPEI Manual	
Protected steel	6.829E-3 or value from CEPEI Manual	
Plastic	7.969E-3 or value from CEPEI Manual	
Distribution Services, Natural Gas Service	Population Emission Factor (Sm³/hr/service)	
Unprotected steel	5.953E-3 or value from CEPEI Manual	
Protected steel	6.270E-4 or value from CEPEI Manual	
Plastic	4.036E-5 or value from CEPEI Manual	
Copper	8.829E-4 or value from CEPEI Manual	

1. CEPEI Methodology Manual. (2013), amended from time to time.

A typical natural gas density is considered to be 0.70772 kg/m³.

a—Table 9 Average emission factors for estimating fugitive equipment leaks at gas transmission and distribution facilities.

b—Table 12 leaker emission factors for estimating fugitive equipment leaks at Canadian natural gas transmission and distribution facilities,

2. US EPA, Mandatory Reporting of greenhouse Gases – Rules and Regulations, Subpart W
Table 7, Dec 23, 2012.

* The distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility.

Table 350-6 Average bleed rates for pneumatic controllers, intermittent bleed devices and pumps (or their equivalents as listed) in the table below (which shall be used for the 2017 calendar year and onwards)

Pneumatic Device	Average Bleed Rate (m ³ /hr)	Coefficients (supply pressure, injection pressure, strokes per min)	Equivalent Device
Generic High Bleed Controller	0.2605	0.0012	-
Generic High Bleed Intermittent Controller	0.2476	0.0012	-
Pressure Controllers - Fisher 4150	0.4209	0.0019	4150
Pressure Controllers - Fisher C1	0.0649	-	-
Pressure Controllers - Fisher 4660	0.0151	0.0003	4660A
Level Controllers Fisher 2500	0.3967	0.0011	2500S, 2503, L3
Level Controllers Fisher 2680	0.2679	0.0014	2680A
Level Controllers Fisher 2900	0.1447	-	2900A, 2901, 2901A
Level Controllers Fisher L2	0.2641	0.0012	-
Level Controllers Murphy LS1200	0.2619	0.0012	LS1100, LS1200N, LS1200DVO
Level Controllers Norriseal 1001	0.1868	-	1001A, 1001XL
Level Controllers SOR 1530	0.0531	-	-
Positioners - Fisher Fieldvue DVC6000	0.2649	0.0011	6030, 6020, 6010
Temperature Controllers - Kimray HT-12	0.0351	-	-
Transducers - Fairchild TXI7800	0.1543	0.0009	TXI7850
Transducers - Fisher 546	0.3547	0.0017	546S
Transducers - Fisher i2P-100	0.2157	0.0009	-
Generic Piston Pump	0.5917	0.00202, 0.000059, 0.0167	-
Generic Diaphragm Pump	1.0542	0.0005, 0.000027, 0.0091	-
Pumps - Morgan HD312	1.1292	0.00418, 0.000034, 0.0073	HD312-3K, HD312-5K
Pumps - Texsteam 5100	0.9670	0.0003, 0.000034, 0.0207	5100LP, 5100H
Pumps - Williams P125	0.4098	0.00019, 0.000024, 0.0076	-
Pumps - Williams P250	0.8022	0.00096, 0.000042, 0.0079	-
Pumps - Williams P500	0.6969	0.00224, -0.000031, 0.0046	-

1- this table provides a list of equivalent pneumatic controllers. If a controller is listed in the equivalents column, then the emission factor or coefficient(s) for the equivalent manufacturer and model provided shall be used

2 – Controllers that do not have a coefficient should use the mean bleed rate instead of the bleed rate equation

3 - All data in Table 350-6 from Final Report – For Determining Bleed Rates for Pneumatic Devices in British Columbia. The Prasino Group. December 2013.

Table 350-7 Nomenclature (subscripts, variables and their descriptions)

Variable Name	Description
A	Variable – Area
A	Subscript – Actual condition for temperature and pressure
CF	Variable – Control factor (fractional)
D	Variable – Diameter
E	Variable – Greenhouse Gas release rate
E	Subscript – exit point
EF	Variable – Emission factor
GOR	Variable – Gas to oil ratio
GWP	Variable – Global warming potential
HHV	Variable – Higher (gross) heating value
I	Subscript - Chemical compound
J	Subscript - Individual device, equipment, meter or well
K	Variable – Specific heat ratio for gases
K	Subscript - Service type (e.g., fuel gas, process gas, liquid, etc.)
L	Variable - Length
L	Subscript - Individual equipment components
M	Variable – Mach number
MW	Variable – Molecular weight
M	Subscript – Operating mode
N	Variable – Count of devices, equipment, meters, wells, events, etc.
N	Variable – Number of carbon atoms in a molecule of a specified
P	Variable – Pressure
R	Variable – Universal Gas Constant
S	Subscript – Standard condition for temperature (15 °C) and pressure (101.325 kPa)
T	Variable – Time duration of event
T	Variable – Temperature (°C)
Q	Variable – Volumetric flow rate
V	Variable - Volume
X	Variable - Mass fraction
Y	Variable - Mole fraction
<i>P</i>	Variable - density
η	Variable – efficiency (fractional)

ON.300 Petrochemical Production

ON.301 Activity Definition

For the purposes of this standard quantification method:

“Petrochemical production” has the same meaning as in the Regulation.

“Person” means a person that engages in petrochemical production.

ON.302 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.300 – ON.305, in an emission report prepared for a calendar year in respect of petrochemical production at a facility:

- (a) CO₂, N₂O, and CH₄ emissions from flares or other combustion devices in tonnes using methods ON.303(a)(1), ON.303(a)(2) or ON.303(c).
- (b) CO₂, N₂O, and CH₄ process emissions from vents in tonnes using method ON.303(a)(3).
- (c) CO₂, N₂O, and CH₄ process emissions from equipment leaks in tonnes using method ON.303(a)(4).
- (d) CO₂ process emissions in tonnes using method ON.303(b).
- (e) CO₂, N₂O, and CH₄ process emissions from ethylene production facilities in tonnes using method ON.303(c).
- (f) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in standard cubic meters for gases; kilolitres for and liquids and tonnes for solid fuels.

Production Parameters

- (g) The annual production of the following products:
 - (1) Carbon black, in tonnes;
 - (2) Styrene, in tonnes;
 - (3) Ethylene produced at the facility with GHGID 1100 in tonnes;
 - (4) Ethylene, and all chemicals (including hydrogen) from the ethylene cracker process at the facility with GHGID 1073, in tonnes;
 - (5) All other chemicals that are not from the ethylene cracker at the facility with GHGID 1073, in tonnes.

ON.303 Calculation of GHG Emissions

Calculate GHG emissions using one of the calculation methodologies in paragraphs (a), (b), or (c):

- (a) Calculation Methodology 1: Calculate the GHG emissions from petrochemical production processes using the methods specific in paragraphs (a)(1) through (a)(3) of this section.
- (1) For flares, calculate CO₂, CH₄ and N₂O emissions using the methods specified in ON.200.
 - (2) For combustion devices other than flares, calculate CO₂, CH₄ and N₂O emissions resulting from the combustion of fuels and process off-gas as specified in paragraphs (a)(2)(i) through (a)(2)(iii):
 - (i) Calculate CO₂ emissions from fuels and process off-gas in accordance with the methods in specified in ON.23.
 - (ii) Calculate CH₄ and N₂O emissions from combustion of fuels using the applicable methods in ON.24. Use the appropriate default emission factors for CH₄ and N₂O from Tables 20-2, 20-4, 20-6, and 20-7.
 - (iii) Calculate CH₄ and N₂O emissions from process off-gas using the applicable Equation 20-12 in ON.24 and the default emission factors of 2.8×10^{-3} kg/GJ for CH₄ and 5.7×10^{-4} kg/GJ for N₂O.
 - (3) Calculate the emissions from process vents using the method specified in ON.203(b) for each process vent that can be reasonably expected to contain greater than 2 per cent by volume CO₂ or greater than 0.5 per cent by volume of CH₄ or greater than 0.01 per cent by volume (100 parts per million) of N₂O.
 - (4) Calculate the emissions from equipment leaks using the method specified in ON.203(i)(1).
- (b) Calculation Methodology 2: Calculate the emissions of CO₂ from each process unit, for each calendar month as described in paragraphs (b)(1) through (b)(5) of this section.
- (1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter. Alternatively, for liquids, the person may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid). Fuels used for combustion purposes are not considered to be feedstocks. The emissions from the combustion of fuels (other than process off-gas) shall be calculated in accordance with the methods specified in ON.23 for CO₂ and the methods specified in ON.24 for CH₄ and N₂O.
 - (2) For each solid feedstock and product, measure the mass used or produced each calendar month.

- (3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample. Alternatively, the person may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis is conducted at least once per month. If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically.
- (4) If the person determines that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 per cent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (b)(3) of this section, the person may calculate the carbon content assuming 100 per cent of that feedstock or product is the specific compound during periods of normal operation. The person shall maintain records of any determination made in accordance with this paragraph (b)(4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. The person shall reevaluate determinations made under this paragraph (b)(4) after any process change that affects the feedstock or product composition. The person shall keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 per cent, the person is no longer permitted to use this alternative method.
- (5) Calculate the CO₂ mass emissions for each petrochemical process unit using Equations 300-2 through 300-5 of this section.
 - (i) Gaseous feedstocks and products. Use Equation 300-1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12} \left[\sum_{i=1}^{j \text{ or } k} \left[(F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC} \right] \right]$$

Equation 300-1

Where:

- C_g = Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kg/yr).
- $(F_{gf})_{i,n}$ = Volume of gaseous feedstock i introduced in month “n” (Rm³) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock introduced in month n in kg and replace the term “ $(MW_f)_i/MVC$ ” with “1”.

- $(CC_{gf})_{i,n}$ = Average carbon content of the gaseous feedstock i for month “ n ” (kg C per kg of feedstock).
- $(MW_f)_i$ = Molecular weight of gaseous feedstock i (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the above $(F_{gf})_{i,n}$ (Rm³/kg-mole).
= $8.3145 * [273.16 + \text{reference temperature in } ^\circ\text{C}] / [\text{reference pressure in kilopascal}]$
- $(P_{gp})_{i,n}$ = Volume of gaseous product i produced in month “ n ” (Rm³) at the same reference conditions as the above $(F_{gf})_{i,n}$. If a mass flow meter is used, measure the gaseous product produced in month “ n ” in kg and replace the term “ $(MW_p)_i/MVC$ ” with “1”.
- $(CC_{gp})_{i,n}$ = Average carbon content of gaseous product i , including streams containing CO₂ recovered for sale or use in another process, for month “ n ” (kg C per kg of product).
- $(MW_p)_i$ = Molecular weight of gaseous product i (kg/kg-mole).
- j = Number of feedstocks.
- k = Number of products.

- (ii) Liquid feedstocks and products. Use Equation 300-2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12} [\sum_{i=1}^{j \text{ or } k} [(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n}]] \quad \text{Equation 300-2}$$

Where:

- C_l = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).
- $(F_{lf})_{i,n}$ = Volume or mass of liquid feedstock i introduced in month “ n ” (m³ of feedstock). If a mass flow meter is used, measure the liquid feedstock in month “ n ” introduced in kg and measure the carbon content of feedstock in kg of C per kg of feedstock.
- $(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for month “ n ” (kg of C per m³ of feedstock when feedstock usage is measured in m³, or kg of C per kg of feedstock when feedstock usage is measured in kg).
- $(P_{lp})_{i,n}$ = Volume or mass of liquid product i produced in month “ n ” (m³). If a mass flow meter is used, measure the liquid product produced in kg and measure the carbon content of liquid product in kg of C per kg of product.
- $(CC_{lp})_{i,n}$ = Average carbon content of liquid product i , including organic liquid wastes, for month “ n ” (kg of C per m³ of product when

liquid product is measured in m³, or kg of C per kg of product when product is measured in kg)

- j = Number of feedstocks.
k = Number of products.

- (iii) Solid feedstocks and products. Use Equation 300-3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12} \left\{ \sum_{i=1}^{j \text{ or } k} \left[(F_{sf})_{i,n} * (CC_{sf})_{i,n} - (P_{sp})_{i,n} * (CC_{sp})_{i,n} \right] \right\} \quad \text{Equation 300-3}$$

Where:

- C_s = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).
(F_{sf})_{i,n} = Mass of solid feedstock i introduced in month “n” (kg).
(CC_{sf})_{i,n} = Average carbon content of solid feedstock i for month “n” (kg C per kg of feedstock).
(P_{sp})_{i,n} = Mass of solid product i produced in month “n” (kg).
(CC_{sp})_{i,n} = Average carbon content of solid product i in month “n” (kg C per kg of product).
j = Number of feedstocks.
k = Number of products.

- (iv) Annual emissions. Use the results from Equations 300-1 through 300-3 of this section, as applicable, in Equation 300-4 of this section to calculate annual CO₂ emissions.

$$CO_2 = 0.001 * 3.664 * (C_g + C_l + C_s) \quad \text{Equation 300-4}$$

Where:

- CO₂ = Annual CO₂ mass emissions from process operations and process off-gas combustion (tonnes/year).
0.001 = Conversion factor from kg to tonnes.
3.664 = Ratio of molecular weight, carbon dioxide to carbon.

- (c) Calculation Methodology 3: (Optional combustion methodology for ethylene production processes) For ethylene production processes, calculate CO₂, CH₄, and N₂O emissions as specified in paragraphs (c)(1) and (c)(2):

- (1) For each flare, calculate CO₂, CH₄, and N₂O emissions using the methodology for flares specified in ON.203(e).
- (2) For all other combustion units, calculate the CO₂ emissions from combustion of fuel that contains ethylene process off-gas using either

Calculation Methodologies 3 or 4 in ON.23, respectively. Calculate CH₄ and N₂O emissions using the applicable method in ON.24 and the emission factors of 2.8 x 10⁻³ kg/GJ for CH₄ and 5.7 x 10⁻⁴ kg/GJ for N₂O. The person is not required to use the same calculation methodology for each stationary combustion unit that burns ethylene process off-gas.

ON.304 Sampling, Analysis, and Measurement Requirements

- (a) If the person calculates emissions using the method specified in ON.303(a):
- (1) Flares. The person shall comply with the monitoring requirements for flares specified in ON.204(e). The person may monitor the carbon content or the high heat value of the flares gas of flares in a petrochemical production facility on a quarterly basis.
 - (2) Process Vents. The person shall comply with the monitoring requirements for process vents specified in ON.204(b).
- (b) If the person calculates emissions using the method specified in ON.303(b):
- (1) Feedstock Consumption. The person shall measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.
 - (2) Product Parameter. The person shall measure the quantity of product parameter using the same plant instruments used for accounting purposes. Equipment used to measure the production parameter quantity shall be:
 - i) calibrated according to the manufacturer's instructions; or, where not available calibrate according to practices used for accounting purposes; and
 - ii) maintained an accuracy of plus or minus 5%.
 - (3) Carbon Content. Except as allowed by ON.303(b)(4), the carbon content of each feedstock and product shall be measured at least once per month using one or more of the methods in Section 5 of this Guideline.

ON.305 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.304, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.304 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:

- (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall,
- (i) Determine the sampling or measurement rate using the following Equation 300-5:

$$R = Q_{S \text{ Act}} / Q_{S \text{ Required}} \quad \text{Equation 300-5}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

$Q_{S \text{ Act}}$ = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.304

- (ii) Replace the missing data as follows,
- (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
- (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data generated from best estimates based on all of the data relating to the processes concerns coke burn, volumetric gas flow, gas volume, number of hours of operation, quantity of raw materials, quantity of product, quantity of steam or quantity of wastewater treated, the replacement data shall be estimated on the basis of all the data relating to the processes used.
- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.390 Petroleum Product Supply

ON.391 Activity Definitions

For the purposes of this method, the following definitions apply:

“Co-process” means processing biomass feedstock material together with petroleum crude oil or petroleum based feedstock in a refinery to produce one or more petroleum products.

“Fractionator” means the owner and operator of a fractionation facility.

“Natural Gas Distributor” has the same meaning as “distributor” in ON.400.

“Petroleum product” means a product listed in Table 390-1 but does not include any fuel that is contained in the fuel tank installed as standard equipment to supply a vehicle’s engine.

“Petroleum product supply” has the same meaning as in the Regulation

“Propane” means propane used for fuel purposes as defined in Canadian General Standards Board standard CGSB 3.14 – Propane for Fuel Purposes,.

“Reference condition” means 15 degrees Celsius and 101.325 kilopascal.

“Refiner” means the owner and operator of a petroleum refinery.

“Supplier” means a person who engages in petroleum product supply.

ON.392 Greenhouse Gas Reporting Requirements

- (a) A supplier shall set out the following information, calculated for the calendar year using standard quantification methods ON.390 - ON.395, in an emission report prepared for a calendar year in respect of petroleum product supply:
- (1) The total greenhouse gas emissions calculated using Equation 390-4 and 390-5 expressed as tonnes of CO₂e.
 - (2) The annual quantity in tonnes or kilolitres of each product in Equation 390-1 that is first placed into the Ontario market.
 - (3) The volume of biomass-based fuel blended with each petroleum product; reported in (a)(2) of this section calculated in accordance with Equation 390-8.
 - (4) The total annual greenhouse gas emissions, expressed in tonnes of CO₂e, that would result from the complete combustion or oxidation of each petroleum product reported in section (a)(1) above, calculated in accordance with ON.393(a).
 - (5) The organization name and facility location of each capped participant, that is not another supplier or a natural gas distributor, to which the person

- has supplied petroleum products during the year, along with the volume of petroleum products that are not automotive gasoline or diesels delivered to each facility, calculated in accordance with ON.393(c).
- (6) A copy of any attestation received by the supplier from capped facilities of capped participants, to which fuel was supplied by the supplier either directly or through a series of transactions that originated with the supplier for the purposes of the calculation in Equation 390-3. In order to be used for the purposes of Equation 390-3 the attestations must:
- a. be signed by the capped participant and
 - b. confirm the total quantity of petroleum products received at the capped facility of the capped participant in the year from the supplier that supplied the petroleum product either directly or through a chain of transactions that originated with the supplier.
- (b) In addition to the requirements in ON.390.(a), refiners and fractionators shall include the following information in the annual report prepared pursuant to the regulation:
- (1) The volume of each type of biomass that was co-processed with petroleum feedstock to produce a petroleum product listed in Table 390-1 expressed in tonnes or kilolitres.
 - (2) The CO₂ emissions, expressed in tonnes that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum feedstocks reported in ON.392(a)(3) above, calculated in accordance with ON.393(b).

ON.393 Calculating CO₂ emissions.

- (a) A supplier shall calculate CO₂ emissions for each petroleum product supplied using Equation 390-1.

$$CO_{2i} = Product_i \times EF_i \quad \text{Equation 390-1}$$

Where:

- CO_{2i} = Total annual CO₂e emissions that would result from the complete combustion or oxidation of each petroleum product “i” expressed in tonnes.
- Product_i = Total annual quantity of petroleum product “i” calculated in accordance with paragraph (g) of this section that is first placed into the Ontario market by the supplier expressed in kilolitres for liquid petroleum products or tonnes for solid petroleum products.

EF_i = Product-specific CO_{2e} emission factor calculated in accordance with ON 393(f) expressed in tonnes of CO_{2e} per kilolitre or per tonne of petroleum product.

(b) A supplier shall use Equation 390-2 to calculate CO₂ emissions for each type of biomass that enters a manufacturing or fractionating facility and is co-processed.

$$CO_{2m_i} = Product_i \times EF_i \times \%Biomass_m \times 0.01$$

Equation 390-2

Where:

CO_{2m_i} = Total annual CO_{2e} emissions that would result from the complete combustion or oxidation of petroleum product “i” produced from biomass “m” expressed in tonnes.

$Product_i$ = Total annual volume of petroleum product “i” first placed into the Ontario market by the supplier expressed in kilolitres.

EF_i = Product-specific CO_{2e} emission factor calculated in accordance with ON.393(f) expressed in tonnes of CO_{2e} per kilolitre.

$\%Biomass_m$ = Annual per cent of biomass_m that enters the manufacturing or fractionating facility that is co-processed with petroleum or natural gas liquid feedstocks to produce a petroleum product reported under paragraph (a) of this section expressed in per cent volume for liquids and per cent weight for solid biomass.

(c) A supplier shall use Equation 390-3 to calculate CO₂ emissions from petroleum products that are supplied to the capped facility of capped participant.

$$CO_{2_{le_i}} = Product_{le_i} \times EF_i$$

Equation 390-3

Where:

$CO_{2_{le_i}}$ = Total annual CO_{2e} emissions that would result from the complete combustion or oxidation of petroleum product “i” supplied to a capped facility of a capped participant, expressed in tonnes.

$Product_{le_i}$ = Total annual volume of petroleum products that are not automotive gasoline or diesels first placed into the Ontario market that are supplied to a capped facility of a capped participant, and recorded in the attestation or attestations provided pursuant to in 392(a)(6) .

EF_i = Product-specific CO₂e emission factor calculated in accordance with ON 393(f) expressed in tonnes of CO₂e per kilolitre or per tonne of petroleum product.

(d) Manufacturers and fractionators shall calculate the total CO₂e emissions from all petroleum products supplied using Equation 390-4.

$$CO_{2r} = \sum (CO_{2i}) - \sum (CO_{2m_i}) - \sum (CO_{2le_i})$$

Equation 390-4

(e) Importers shall calculate the total CO₂e emissions from all petroleum products imported using Equation 390-5.

$$CO_{2x} = \sum (CO_{2i}) - \sum (CO_{2m_i}) - \sum (CO_{2le_i})$$

Equation 390-5

(f) Suppliers shall determine the emission factors (EF_i) for each petroleum product using one of the following calculation methodologies. The same calculation methodology shall be used for the entire quantity of the petroleum product for the calendar year.

(1) Calculation Methodology 1. Use the default CO₂e emission factor listed for the petroleum product in Table 390-1

(2) Calculation Methodology 2. Use Equation 390-6 with the following values

(i) For solid petroleum products, develop emission factors according to Equation 390-6 using direct measurements of carbon share according to methods set out in ON.394(c).

(ii) For non-solid petroleum products, develop emission factors according to Equation 390-6 using direct measurements of density and carbon share according to methods set out in ON.394(c).

$$EF_i = (Density \times Carbon\ share \times \frac{44}{12}) + 0.001 \times (21 \times EF_{CH_4} + 310 \times EF_{N_2O})$$

Equation 390-6

Where:

EF_i = Emission factor of the petroleum product expressed in tonnes of CO₂e per kilolitre or per tonne of petroleum product.

Density = Density of the petroleum product or natural gas liquid expressed in tonnes per kilolitre for non-solid petroleum products or having a value of 1 for solid petroleum products.

- Carbon share = weight per cent of carbon in the petroleum product, expressed as a fraction such as expressing 75% as 0.75.
- 44/12 = Conversion factor for carbon to carbon dioxide.
- EF_{CH_4} = CH_4 Emissions factor of the petroleum product expressed in grams of CH_4 per litre from the relevant table in ON.20.
- EF_{N_2O} = N_2O Emissions factor of the petroleum product expressed in grams of N_2O per litre from the relevant table in ON.20.

(g) The supplier that produces a petroleum product by blending a petroleum-based product with a biomass-based fuel shall calculate the volume of the petroleum product according to the following methodology.

(1) Use Equation 390-8 to calculate $Product_b$ for use in Equation 390-9.

$$Product_b = Product_t \times \%Vol_i \times 0.01 \quad \text{Equation 390-8}$$

Where:

- $Product_b$ = Total volume of petroleum products that is biomass-based fuels in kilolitres.
- $Product_t$ = Total volume of petroleum products and blended biomass-based fuels that is used as a fuel in kilolitres.
- $\%Vol_i$ = Percent volume of $Product_t$ that is biomass.

(2) Use Equation 390-9 to calculate $Product_i$.

$$Product_i = Product_t - Product_b \quad \text{Equation 390-9}$$

ON.394 Sampling, Analysis, and Measurement Requirements

(a) Determination of quantity of petroleum products.

(1) The supplier required to determine the quantities of petroleum products pursuant to this method shall determine those quantities using the following:

- (i) Appropriate standard methods published by a consensus-based standards organization; or,
- (ii) Where no such methods exist, industry standard practices.

(b) Equipment Calibration.

(1) The supplier required to determine quantities of petroleum products pursuant to this method shall calibrate all measurement equipment prior to its first use for the purposes of this method using a standard method published by a consensus based standards organization or according to

- the calibration or verification procedures specified by the equipment manufacturer.
- (2) The supplier required to determine quantities of petroleum products pursuant to this method shall recalibrate equipment mentioned in (1) at the minimum frequency specified by the standard method or by the equipment manufacturer.
 - (3) Sections (1) and (2) above do not apply to any equipment used for financial transactions.
- (c) Procedures for determining emissions factors using direct measurements under Calculation Methodology 2 of ON.393(f)(2).
- (1) A supplier required to determine emissions factors using direct measurements pursuant to ON.393(e)(2) shall collect at least one sample of each petroleum product using an appropriate standard method published by a consensus-based standards organization for each calendar month of the calendar year in which the petroleum product is supplied in Ontario.
 - (2) A supplier required to determine emissions factors shall ensure the mixing and handling of samples is performed using an appropriate standard method published by a consensus-based standards organization.
 - (3) A supplier required to determine density measurements shall use the following for each sample collected under (1).
 - (i) For all non-solid petroleum products, the supplier shall test for density using an appropriate standard method published by a consensus-based standards organization.
 - (ii) The density value for each petroleum product shall be generated by a single composite sample or an average of multiple samples.
 - (iii) All measurements of density shall be temperature-adjusted and pressure-adjusted to the reference conditions contained in this method.
 - (4) For each sample collected under (1) the supplier required to determine the carbon share measurement shall do the following:
 - (i) Test for carbon share using an appropriate standard method published by a consensus-based standards organization.
 - (ii) If the supplier uses a standard method that involves gas chromatography to determine the per cent mass of each component in a petroleum product the supplier shall calculate the petroleum product's carbon share using Equation 390-7

$$Carbon\ Share = \sum (\%Composition_{i...n} \times \%Mass_{i...n})$$

Equation 390-7

Where:

$\%Composition_{i...n}$ = Per cent of total mass of each molecular component in the petroleum product

$\%Mass_{i...n}$ = Per cent of total mass that carbon represents in each molecular component of the petroleum product.

(iii) The carbon share for each petroleum product shall be generated by a single composite sample or an average of multiple samples.

ON.395 Procedures for estimating missing data

(a) Determination of quantity.

The supplier shall ensure that whenever the quantity of one or more petroleum products or types of biomass during any period is not measured the following missing data procedures are used:

- (1) For quantities of a petroleum product that are purchased or sold, the missing data shall be substituted using the supplier's established procedures for billing purposes.
- (2) For quantities of a petroleum product that are not purchased or sold but for which the custody is transferred, the missing data shall be substituted using the supplier's established procedures for tracking purposes.

(b) Determination of emission factor.

Where any of the procedures in ON.393(f)(2) cannot be followed to develop an emission factor for any reason, the supplier shall use ON.393(f)(1) for the entire calendar year.

Table 390-1
Default Factors for Petroleum Products

Petroleum Products	Emission Factor (tonnes CO₂e /kL)
Automotive Gasoline	2.361
Diesels	3.007
Light fuel oils (No. 1,2)	2.735
Heavy fuel oils (No. 3, 4, 5, 6)	3.146
Petroleum Coke	3.837
Propane*	1.544

*The emission factors for propane are based on a reference condition of 15 degrees Celsius and saturation pressure.

ON.200 Petroleum Refining

ON.201 Activity Definition

For the purposes of this standard quantification method:

“Petroleum refining” has the same meaning as in the Regulation.

“Person” means a person that engages in petroleum refining.

“CAN-CWB Methodology” means the calculation methodology described in “The CAN-CWB Methodology for Regulatory Support: Public Report” dated January 2014, prepared by Solomon Associates.

ON.202 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.200 – ON.205, in an emission report prepared for a calendar year in respect of petroleum refining at a facility:

- (a) Catalyst Regeneration. Report CO₂, CH₄, and N₂O emissions.
- (b) Process Vents. Report CO₂, N₂O, and CH₄ emissions.
- (c) Asphalt Production. Report CO₂ and CH₄ emissions.
- (d) Sulphur Recovery. Report CO₂ emissions.
- (e) Flares and Other Control Devices. Report CO₂, N₂O, and CH₄ emissions.
- (f) Above-Ground Storage Tanks. Report CH₄ emissions.
- (g) Wastewater Treatment. Report CH₄ and N₂O emissions from anaerobic treatment.
- (h) Oil-water Separators. Report CH₄ emissions from oil-water separators.
- (i) Equipment Leaks. Report CH₄ emissions.
- (j) Petroleum Coke calcining units. Report CO₂, N₂O, and CH₄ emissions.
- (k) Uncontrolled blowdown systems. Report CH₄ emissions.
- (l) Loading Operations. Report CH₄ emissions.
- (m) Delayed Coking Units. Report CH₄ emissions.
- (n) The following Complexity weighted barrel (CWB) parameters:
 - (1) The Direct Only CAN-CWB_(without hydrogen and cogeneration), in units of complexity weight barrel per calendar day (CWB/CD) and in units of complexity weight barrel per calendar year (CWB/year).
 - (2) The throughput for each of the Standard Refining Process units identified in the CAN-CWB Methodology.
 - (3) The Total CO₂e emissions in the calendar year associated with the petroleum refinery, including emissions associated with Hydrogen

Generation units (listed in Appendix B of the CAN-CWB Methodology), indirect emissions but excluding cogeneration emissions expressed in tonnes.

- (4) The Direct-only CO₂ emissions in the calendar year from the petroleum refinery including Hydrogen Generation units emissions but excluding cogeneration emissions expressed in tonnes.
- (5) The Direct-only CO₂ emissions in the calendar year from the petroleum refinery excluding Hydrogen Generation units and cogeneration emissions expressed in tonnes.
- (6) The Total Input Barrels described in the CAN-CWB Methodology expressed in barrels per calendar day.
- (7) The Non-Crude Input Barrels described in the CAN-CWB Methodology (expressed in barrels per calendar day).
- (8) The Imported Steam to the refinery, including steam originating from a cogeneration unit located inside the refinery expressed in million BTU per calendar day.
- (9) The Imported Electricity to the refinery, including electricity originating from a cogeneration unit located inside the refinery expressed in megawatt hour per calendar day.
- (10) The Exported Steam from the refinery, net of steam originating from a cogeneration unit located inside the refinery expressed in thousand BTU per calendar day.
- (11) The Exported Electricity from the refinery, net of electricity originating from a cogeneration unit located inside the refinery expressed in kilowatt hour per calendar day.

ON.203 Calculation of Greenhouse Gas Emissions

The person shall calculate emissions for the following sources at petroleum refineries : catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; petroleum 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; and sulphur recovery plants. The person must report emissions from hydrogen production under the hydrogen production method. .

The person shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section. If a continuous emissions monitor is used to measure CO₂ emissions from process vents, asphalt production, sulphur recovery, or other control devices then the person shall calculate the CO₂ emissions from these processes using a continuous emissions monitoring system (CEMS) as specified in Calculation Methodology 4 of ON.23. When the flue gas from two or more

processes or stationary combustion sources are discharged through a common stack or duct before exiting to the atmosphere and if CEMS as specified in Calculation Methodology 4 of ON.23 are used to continuously monitor the CO₂ emissions, a person may report the combined emissions from the processes or stationary combustion sources sharing the common stack or duct instead of separately reporting the GHG emission from individual processes or stationary combustion sources.

(a) Catalyst Regeneration. The person shall calculate the CO₂, CH₄, and N₂O process emissions resulting from catalyst regeneration using the methods in paragraph (a)(1), (a)(2) and (a)(3), respectively.

(1) For units equipped with CEMS, the person shall calculate CO₂ process emissions resulting from catalyst regeneration using CEMS in accordance with Calculation Methodology 4 of ON.23. In the absence of CEMS data, the person shall use the methods in paragraphs (a)(1)(A) through (a)(1)(C).

(A)

(i) The person shall calculate process CO₂ emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-1b, 200-2, and 200-3 in section (a)(1)(A)(ii) below.

$$CO_2 = \sum_{i=1}^n CR_i \times CF \times 3.664 \times 0.001 \quad \text{Equation 200-1}$$

Where:

CO ₂	=	CO ₂ emissions (tonnes/yr)
n	=	number of hours of operation in the report year
CR _i	=	hourly coke burn rate in kg/ hr
CF	=	carbon fraction in coke burned
3.664	=	ratio of molecular weights, carbon dioxide to carbon
0.001	=	conversion factor from kg to tonnes

(ii) Alternatively, the person may calculate process CO₂ emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1b and 200-2.

$$CO_2 = \sum_{p=1}^n \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right] \quad \text{Equation 200-1b}$$

Where:

CO ₂	=	CO ₂ emissions (tonnes/yr)
Q _r	=	volumetric flow rate of exhaust gas before entering the emission control system using equation 200-2 and at reference temperature and pressure conditions as used by the facility (dRm ³ /hr)
%CO ₂	=	average hourly CO ₂ concentration in regenerator exhaust, per cent by volume – dry basis
%CO	=	average hourly CO concentration in regenerator exhaust, per cent by volume – dry basis. When there is no post-combustion device, assume %CO to be zero.
44	=	molecular weight of CO ₂ (kg/kg-mole)
MVC	=	molar volume conversion factor at the same reference conditions as the above Q _r (Rm ³ /kg-mole)
	=	8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
0.001	=	conversion factor from kg to tonnes
n	=	number of hours of operation in the report year

- (iii) 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 200-2 of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2} \quad \text{Equation 200-2}$$

Where:

Q _r	=	volumetric flow rate of exhaust gas from regenerator before entering the emission control system at reference temperature and pressure conditions as used by the facility (dRm ³ /min)
Q _a	=	volumetric flow rate of air to regenerator, as determined from control room instrumentation at reference temperature and pressure conditions used for Q _r (dRm ³ /min)
%Q _{xy}	=	oxygen concentration in oxygen enriched air stream, per cent by volume – dry basis
Q _{oxy}	=	volumetric flow rate of O ₂ enriched air to regenerator as determined from catalytic cracking unit control room instrumentation at reference temperature and pressure conditions used for Q _r (dRm ³ /min)
%CO ₂	=	carbon dioxide concentration in regenerator exhaust, per cent by volume – dry basis

- %CO = CO concentration in regenerator exhaust, per cent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
- %O₂ = O₂ concentration in regenerator exhaust, per cent by volume – dry basis

(iv) Calculate the hourly coke burn rate using Equation 200-3 or from facility measurement or engineering estimate:

$$CR_i = K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO / 2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})$$

Equation 200-3

Where:

- CR_i = hourly coke burn rate in kg/ hr
- K₁, K₂, K₃ = material balance and conversion factors (K₁, K₂, and K₃ from Table 200-1 or from facility measurement or engineering estimate
- Q_r = volumetric flow rate of exhaust gas before entering the emission control system from Equation 200-2 (dRm³/min)
- Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in Q_r (dRm³/min)
- %CO₂ = CO₂ concentration in regenerator exhaust, per cent by volume – dry basis
- %CO = CO concentration in regenerator exhaust, per cent by volume – dry basis
- %O₂ = O₂ concentration in regenerator exhaust, per cent by volume – dry basis
- Q_{oxy} = volumetric flow rate of O₂ enriched air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in Q_r (dRm³/min)
- %O_{xy} = O₂ concentration in O₂ enriched air stream inlet to regenerator, per cent by volume – dry basis

(B) The person shall calculate process CO₂ emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-4.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664$$

Equation 200-4

Where:

- CO₂ = CO₂ emissions (tonnes/yr)
- CC_{irc} = average catalyst regeneration rate (tonnes/hr)

CF_{spent}	=	weight carbon fraction on spent catalyst
CF_{regen}	=	weight carbon fraction on regenerated catalyst (default = 0)
H	=	hours regenerator was operational (hr/yr)
3.664	=	ratio of molecular weights, CO_2 to carbon

(C) The person shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equations 200-5

$$CO_2 = \sum_1^n \left[(CB_Q)_n \times CC \times 3.664 \times 0.001 \right] \quad \text{Equation 200-5}$$

Where:

CO_2	=	Annual CO_2 emissions (tonnes/year).
CBQ	=	Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n	=	Number of regeneration cycles in the calendar year.
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
3.664	=	ratio of molecular weights, carbon dioxide to carbon
0.001	=	Conversion factor (tonne/kg).

(2) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-6 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \quad \text{Equation 200-6}$$

Where:

CH_4	=	Annual methane emissions from coke burn-off (tonnes CH_4 /year).
CO_2	=	Emission rate of CO_2 from coke burn-off calculated in paragraph (a)(1) of this section, as applicable (tonnes/year).
EmF_1	=	Default CO_2 emission factor for petroleum coke of 97 kg CO_2 /GJ
EmF_2	=	Default CH_4 emission factor of 2.8×10^{-3} kg CH_4 /GJ.

(3) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-7 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right) \quad \text{Equation 200-7}$$

Where:

- N_2O = Annual nitrous oxide emissions from coke burn-off (tonne N_2O /year).
- CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (a)(1) of this section, as applicable (tonnes/year).
- EmF_1 = Default CO_2 emission factor for petroleum coke of 97 kg CO_2 /GJ .
- EmF_3 = Default N_2O emission factor of 5.7×10^{-4} kg N_2O /GJ

(b) Process Vents. Except for process emissions reported under other requirements of this Regulation, the person shall calculate process emissions of CO_2 , CH_4 , and N_2O from process vents using Equation 200-8 for each process vent that can be reasonably expected to contain greater than 2 per cent by volume CO_2 or greater than 0.5 per cent by volume of CH_4 or greater than 0.01 per cent by volume (100 parts per million) of N_2O .

$$E_x = \sum_{i=1}^n VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001 \quad \text{Equation 200-8}$$

Where:

- E_x = Annual emissions of x (tonnes/yr), where x = CO_2 , N_2O , or CH_4
- VR_i = Average volumetric flow rate for venting event i from measurement data, process knowledge or engineering estimates at reference temperature and pressure conditions as used by the facility (Rm^3 /unit time). If a mass flow meter is used, measure the flow rate in kg/unit time and replace the term " MW_x/MVC " with "1".
- F_{xi} = Molar fraction of x in vent gas stream during event i from measurement data, process knowledge or engineering estimates.
- MW_x = molecular weight of x (kg/kg-mole)
- MVC = molar volume conversion factor at the same reference conditions as the above VR_i (Rm^3 /kg-mole).
= $8.3145 * [273.16 + \text{reference temperature in } ^\circ C] / [\text{reference pressure in kilopascal}]$
- VT_i = time duration of venting event i, in same units of time as VR_i
- n = number of venting events in report year
- 0.001 = conversion factor from kg to tonnes

(c) Asphalt Production. The person shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using either process vent method specified in paragraph (b) or according to the applicable provisions in paragraphs (c)(1) and (c)(2) of this section.

- (1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO₂ and CH₄ emissions using Equations 200-9 and 200-10 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB,CO_2}) \quad \text{Equation 200-9}$$

Where:

- CO₂ = Annual CO₂ emissions from uncontrolled asphalt blowing (tonnes CO₂/year).
 Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
 E_{FAB,CO2} = Emission factor for CO₂ from uncontrolled asphalt blowing from facility-specific test data (tonnes CO₂/MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH_4}) \quad \text{Equation 200-10}$$

Where:

- CH₄ = Annual methane emissions from uncontrolled asphalt blowing (tonnes CH₄/year).
 Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
 E_{FAB,CH4} = Emission factor for CH₄ from uncontrolled asphalt blowing from facility-specific test data (tonnes CH₄/MMbbl asphalt blown); default = 580.

- (2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO₂ and CH₄ emissions using Equations 200-11 and 200-12 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (e) of this section or in the stationary combustion unit emissions required under ON.20.

$$CO_2 = 0.98 \times (Q_{AB} \times CEF_{AB} \times 3.664) \quad \text{Equation 200-11}$$

Where:

- CO₂ = Annual CO₂ emissions from controlled asphalt blowing (tonnes CO₂/year).
 0.98 = Assumed combustion efficiency of thermal oxidizer or flare.
 Q_{AB} = Quantity of asphalt blown (MMbbl/year).
 CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (tonnes C/MMbbl asphalt blown); default = 2,750.
 3.664 = ratio of molecular weights, carbon dioxide to carbon

$$CH_4 = 0.02 \times (Q_{AB} \times EF_{AB,CH_4}) \quad \text{Equation 200-12}$$

Where:

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

- (d) Sulphur Recovery. The person shall calculate CO₂ process emissions from sulphur recovery units (SRUs) using Equation 200-13. For the molar fraction (MF) of CO₂ in the sour gas, use either a default factor of 0.20, engineering estimates or a source specific molar fraction value derived from source tests conducted at least once per calendar year. The source test shall be repeated in each future year to update the source specific emission factors annually.

$$CO_2 = FR \times MW_{CO_2} / MVC \times MF \times 0.001 \quad \text{Equation 200-13}$$

Where:

- CO₂ = emissions of CO₂ (tonnes/yr)
- FR = volumetric flow rate of acid gas to SRU at reference temperature and pressure conditions as used by the facility (Rm³/year). If a mass flow meter is used, measure the acid gas flow in kg per year and replace the term "MW_{CO2}/MVC" with "1"
- MW_{CO2} = molecular weight of CO₂ (44 kg/kg-mole)
- MVC = molar volume conversion factor at the same reference conditions as the above FR (Rm³/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
- MF = molar fraction (%) of CO₂ in sour gas based on measurement or engineering estimate (default MF = 20% expressed as 0.20)
- 0.001 = conversion factor from kg to tonnes

(e) Flares and Other Control Devices.

- (1) The person shall calculate and report CO₂, CH₄ and N₂O emissions resulting from the combustion of flare pilot gas using the appropriate method(s) specified in section ON.23 or ON.24.
- (2) The person shall calculate and report CO₂ emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

- (i) Heat value or carbon content measurement. If the person has a continuous high heat value monitor or gas composition monitor on the flare or if the person monitors these parameters at least weekly, the person shall use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare using the applicable methods in paragraphs (e)(2)(i)(A) and (e)(2)(i)(B).
- (A) If the person monitors gas composition, calculate the CO₂ emissions from the flare using Equation 200-14 of this section. If daily or more frequent measurement data is available, the person shall use daily values when using Equation 200-14 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^n \left[3.664 \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \text{Equation 200-14}$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (tonnes/year).
- 0.98 = Assumed combustion efficiency of a flare.
- 0.001 = Conversion factor from kg to tonnes.
- n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
- p = Measurement period index.
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon
- (Flare)_p = Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm³/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term “(MW)_p/MVC” with “1”.
- (MW)_p = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
- MVC = Molar volume conversion factor at the same reference conditions as the above (Flare)_p (Rm³/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
- (CC)_p = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

- (B) If the person monitors heat content but do not monitor gas composition, calculate the CO₂ emissions from the flare using Equation 200-15 of this section. If daily or more frequent measurement data is available, the person shall use daily values when using Equation 200-15 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^n [(Flare)_p \times (HHV)_p \times EmF] \quad \text{Equation 200-15}$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (tonnes/year).
 0.98 = Assumed combustion efficiency of a flare.
 0.001 = Conversion factor from kg to tonnes.
 n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
 p = Measurement period index.
 (Flare)_p = Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm³/period). If a mass flow meter is used, the person shall also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[m³] = Flare [kg] × MVC/(MW)_p, where MVC is the molar volume conversion factor at the same reference conditions as (Flare)_p (Rm³/kg-mole) and (MW)_p is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
 = 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
 (HHV)_p = High heat value for the flare gas combusted during measurement period (GJ per Rm³). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
 EmF = Default CO₂ emission factor of 57 kilograms CO₂/GJ (HHV basis).

- (ii) Alternative Method. For startup, shutdown, and malfunctions during which the person were unable to measure the parameters required by Equations 200-14 and 200-15 of this section, the person shall determine the quantity of gas discharged to the flare separately for each start-up, shutdown, or malfunction, and calculate the CO₂ emissions as specified in paragraphs (e)(2)(ii)(A) of this section.

- (A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event.
- (B) For the reporting of emissions from normal operation flares in the year 2011, the person may use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculation. If the person is unable to use the methods in ON.203(e)(2)(i) for the reporting of emissions from normal operation of flares in the year 2012 due to health or safety reasons, the person may use the alternate method in the subsection for the reporting of emissions from normal operation of flares in the year 2012 if it is consented to in writing by the Director.
- (C) Calculate the CO₂ emissions using Equation 200-16 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^n \left[3.664 \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \text{Equation 200-16}$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (tonnes/year).
- 0.98 = Assumed combustion efficiency of a flare.
- 0.001 = Conversion factor from kg to tonnes.
- n = Number of start-up, shutdown, and malfunction events during the calendar year.
- p = Start-up, shutdown, malfunction and other measurement period index.
- (Flare_{SSM})_p = Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, at reference temperature and pressure conditions as used by the facility (Rm³/event). If a mass flow meter is used, measure the flare gas combusted in kg per event and replace the term “(MW)_p/MVC” with “1”.
- (MW)_p = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the above (Flare_{SSM})_p (Rm³/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

- (CC)_p = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).
3.664 = Ratio of molecular weights, carbon dioxide to carbon

(3) The person shall calculate and report CH₄ and N₂O emissions resulting from the combustion of hydrocarbons routed to flares for destruction using the methods specified in paragraphs (e)(3)(A) and (e)(3)(B):

(A) Calculate CH₄ using Equation 200-17 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH_4} \quad \text{Equation 200-17}$$

Where:

- CH₄ = Annual methane emissions from flared gas (tonnes CH₄/year).
CO₂ = Emission rate of CO₂ from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).
EmF_{CH₄} = Default CH₄ emission factor for Petroleum Products of 2.8 x 10⁻³ kg/GJ
EmF = Default CO₂ emission factor for flare gas of 57 kilograms CO₂/GJ (HHV basis).
0.02/0.98 = correction factor for flare combustion efficiency.
16/44 = correction factor ratio of the molecular weight of CH₄ to CO₂
f_{CH₄} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(B) Calculate N₂O emissions using Equation 200-18 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N_2O}}{EmF} \right) \quad \text{Equation 200-18}$$

Where:

- N₂O = Annual nitrous oxide emissions from flared gas (tonnes N₂O/year).
CO₂ = Emission rate of CO₂ from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).
EmF_{N₂O} = Default N₂O emission factor for petroleum products of 5.7 x 10⁻⁴ kg/GJ.
EmF = Default CO₂ emission factor for flare gas of 57 kilograms CO₂/GJ (HHV basis).

- (4) The person who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO₂ emissions using Equation 200-19. The person shall determine CCA and MWA quarterly using methods specified in ON.20 and use the annual average values of CCA and MWA to calculate CO₂ emissions.

$$CO_2 = GV_A \times CCA \times MW_A / MVC \times 3.664 \times 0.001 \quad \text{Equation 200-19}$$

Where:

CO ₂	=	CO ₂ emissions (tonnes/year)
GV _A	=	volume of gas A destroyed annually at reference temperature and pressure conditions as used by the facility (Rm ³ /year). If a mass flow meter is used, measure the gas destroyed in kg and replace the term “MW _A /MVC” with “1”.
CC _A	=	carbon content of gas A (kg C/kg fuel)
MW _A	=	molecular weight of gas A
MVC	=	molar volume conversion factor at the same reference conditions as the above GV _A (Rm ³ /kg-mole). = 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
3.664	=	ratio of molecular weights, carbon dioxide to carbon
0.001	=	conversion factor from kg to tonnes

- (f) Storage Tanks. For storage tanks other than those processing unstabilized crude oil except as provided in paragraph (f)(3) of this section, calculate CH₄ emissions using the applicable methods in paragraphs (f)(1) and (f)(2) of this section.

- (1) For storage tanks other than those processing unstabilized crude oil, the person shall either calculate CH₄ emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume per cent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: “Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources”, including TANKS Model (Version 4.09D) or similar programs, or estimate CH₄ emissions from storage tanks using Equation 200-20 of this section.

$$CH_4 = (0.1 \times Q_{Ref}) \quad \text{Equation 200-20}$$

Where:

CH ₄	=	Annual methane emissions from storage tanks (tonnes/year).
0.1	=	Default emission factor for storage tanks (tonne CH ₄ /MMbbl).

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

- (2) For storage tanks that process unstabilized crude oil, calculate CH₄ 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 200-21 of this section.

$$CH_4 = (995,000 \times Q_{un} \times \Delta P) \times MF_{CH_4} \times \frac{16}{MVC} \times 0.001 \quad \text{Equation 200-21}$$

Where:

- CH₄ = Annual methane emissions from storage tanks (tonnes/year).
- Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).
- ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
- MF_{CH_4} = Mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH₄/kg-mole gas); use 0.27 as a default if measurement data is not available.
- 995,000 = Correlation Equation factor (cubic feet gas per MMbbl per psi)
- 16 = Molecular weight of CH₄ (kg/kg-mole).
- MVC = Molar volume conversion (849.5 cubic feet/kg-mole).
- 0.001 = Conversion factor (tonne/kg).

- (3) The person does not need to calculate CH₄ emissions from storage tanks that meet any of the following descriptions:
- (i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
 - (ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
 - (iii) Bottoms receivers or sumps;
 - (iv) Vessels storing wastewater; or
 - (v) Reactor vessels associated with a manufacturing process unit.

(g) Industrial Wastewater Processing.

- (1) The person shall calculate CH₄ emissions from anaerobic wastewater treatment (such as anaerobic reactor, digester, or lagoon) using Equation 200-22 or Equation 200-23.

$$CH_4 = Q \times COD_{qave} \times B \times MCF \times 0.001 \quad \text{Equation 200-22}$$

$$CH_4 = Q \times BOD_{5qave} \times B \times MCF \times 0.001 \quad \text{Equation 200-23}$$

Where:

- CH₄ = emission of methane (tonnes/yr)
- Q = volume of wastewater treated (m³/yr)
- COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m³)
- BOD_{5qave} = average of quarterly determinations of five-day biochemical oxygen demand of the wastewater (kg/m³)
- B = methane generation capacity (B = 0.25 kg CH₄/kg COD and 0.06 kg CH₄/kg BOD₅)
- MCF = methane correction factor for anaerobic decay (0-1.0) from Table 200-2
- 0.001 = conversion factor from kg to tonnes

(2) For anaerobic processes from which biogas is recovered and not emitted, the person shall adjust the CH₄ emissions calculated in paragraph (g)(1) by the amount of CH₄ collected.

(3) The person shall calculate N₂O emissions from wastewater treatment using Equation 200-24.

$$N_2O = Q \times N_{qave} \times EF_{N_2O} \times 1.571 \times 0.001 \quad \text{Equation 200-24}$$

Where:

- N₂O = emissions of N₂O (tonnes/yr)
- Q = volume of wastewater treated (m³/yr)
- N_{qave} = average of quarterly determinations of N in effluent (kg N/m³)
- EF_{N₂O} = emission factor for N₂O from discharged wastewater (0.005 kg N₂O-N/kg N)
- 1.571 = conversion factor – kg N₂O-N to kg N₂O
- 0.001 = conversion factor from kg to tonnes

(h) Oil-Water Separators. The person shall calculate CH₄ emissions from oil-water separators using Equation 200-25. For the CF_{NMHC} conversion factor, the person shall use either a default factor of 0.6 or species specific conversion factors determined by sampling and analysis.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001 \quad \text{Equation 200-25}$$

Where:

- CH₄ = emission of methane (tonnes/yr)
- EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m³) from Table 200-3.

V_{water} = volume of waste water treated by the separator (m³/yr)
 CF_{NMHC} = NMHC to CH₄ conversion factor
 0.001 = conversion factor from kg to tonnes

(i) Equipment leaks. Calculate CH₄ emissions using the method specified in either paragraph (i)(1) or (i)(2) of this section.

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

(2) Use Equation 200-26 of this section.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \text{ Equation 200-26}$$

Where:

CH_4 = Annual methane emissions from equipment leaks (tonnes/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.

(j) Petroleum Coke Calcining. The person shall calculate GHG emissions according to the applicable provisions in paragraphs (j)(1) through (j)(3) of this section.

(1) If the person operates and maintains a CEMS that measures CO₂ emissions according to ON.23, the person shall calculate and report CO₂ emissions for coke calcining by following the CEMS Calculation Methodology 4 specified in ON.23. If the coke calcining unit is not equipped with CEMS shall either install a CEMS that complies with the CEMS requirements in ON.20, or follow the requirements of paragraph (j)(2) of this section.

(2) Calculate the CO₂ emissions from the coke calcining unit using Equation 200-27 of this section.

$$CO_2 = 3.664 \times (M_{in} \times CC_{GC} - (M_{out} + M_{dust}) \times CC_{MPC}) \text{ Equation 200-27}$$

Where:

CO_2	= Annual CO_2 emissions (tonnes/year).
M_{in}	= Annual mass of green coke fed to the coke calcining unit from facility records (tonnes/year).
CC_{GC}	= Average mass fraction carbon content of green coke from facility measurement data (tonne carbon/tonne green coke).
M_{out}	= Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (tonnes 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 (tonne 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 (tonne carbon/tonne petroleum coke).
3.664	= ratio of molecular weights, carbon dioxide to carbon

(3) For all Petroleum coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (j)(1) or (j)(2), as applicable, and calculate CH_4 and N_2O using the following methods:

- (i) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-28 of this section.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \quad \text{Equation 200-28}$$

Where:

CH_4	= Annual methane emissions (tonnes CH_4 /year).
CO_2	= Emission rate of CO_2 calculated in paragraphs (i)(1) and (i)(2) of this section, as applicable (tonnes/year).
EmF_1	= Default CO_2 emission factor for petroleum coke (97.12 kg CO_2 /GJ).
EmF_2	= Default CH_4 emission factor of 2.8×10^{-3} kg CH_4 /GJ.

- (ii) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-29 of this section.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right) \quad \text{Equation 200-29}$$

Where:

N_2O	= Annual nitrous oxide emissions (tonnes N_2O /year).
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- CO₂ = Emission rate of CO₂ from paragraphs (i)(1) and (i)(2) of this section, as applicable (tonnes/year).
- EmF₁ = Default CO₂ emission factor for petroleum coke (97 kg CO₂/GJ)
- EmF₃ = Default N₂O emission factor of 5.7 x 10⁻⁴ kg N₂O/GJ).

- (k) Uncontrolled Blowdown Systems. For uncontrolled blowdown systems, the person shall use the methods for process vents in paragraph (b) of this section.
- (l) Loading Operations. For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume per cent or more, calculate CH₄ 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 per cent, the person may assume zero methane emissions.
- (m) Delayed coking units. Calculate the CH₄ emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (m)(1) or (m)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. The person shall use the method in paragraph (m)(1) of this section if the person adds water or steam to the vessel after it is vented to the atmosphere.
- (1) Use the process vent method in paragraph (b) of this section and also calculate the CH₄ emissions from the subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section. If the person has coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 101.325)}{101.325} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH_4} \times 0.001 \right) \quad \text{Equation 200-30}$$

Where:

- CH₄ = Annual methane emissions from the delayed coking unit vessel opening (tonnes/year).
- N = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
- H = Height of coking unit vessel (metres).

P_{CV}	=	Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (l)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (kilopascals)
101.325	=	Assumed atmospheric pressure (kilopascals, kPa)
f_{void}	=	Volumetric void fraction of coking vessel prior to steaming based on engineering judgment at reference temperature and pressure conditions as used by the facility (m^3 gas/ m^3 of vessel);
D	=	Diameter of coking unit vessel (metres).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the cooking vessel (Rm^3/kg -mole). = $8.3145 * [273.16 + \text{reference temperature in } ^\circ C] / [\text{reference pressure in kilopascal}]$
MF_{CH_4}	=	Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4 /kg-mole gas, wet basis);
0.001	=	Conversion factor from kg to tonne.

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If the person has coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

(n) $CAN-CWB_{(\text{without } H_2 \text{ and cogeneration)}}$

Calculate $CAN-CWB_{(\text{without } H_2 \text{ and cogeneration)}}$ using the following steps. This value excludes hydrogen production from Hydrogen Generation units and excludes steam and electricity generation from a cogeneration unit located inside the refinery.

(1) Calculate the CWB_{ref} using the CAN-CWB Methodology for all Standard Refining Process Units, including the hydrogen generated via Hydrogen Generation units, if present expressed in CWB_{ref} per calendar day. Exclude CWB adjustments associated with Sales and Exports of steam and electricity resulting from the presence of a cogeneration unit inside the refinery.

(2) Calculate the Petroleum Refinery 'direct-only emissions' expressed in tonnes CO_2e per year) including Hydrogen Generation units emissions

- (reported under ON.132), if that process unit is present. Exclude from these emissions the cogeneration unit emissions, if present inside the refinery.
- (3) Calculate the Petroleum Refinery 'indirect emissions' using the CAN-CWB Methodology expressed in tonnes CO_{2e} per year. Use an emission factor of 0.521 tonnes CO_{2e} per MWh for calculating indirect emissions from electricity obtained from outside the refinery and from a cogeneration unit located inside the refinery. Use an emission factor of 0.059 tonne CO_{2e} per million Btu/d for calculating indirect emissions from steam imported from outside the refinery and from a cogeneration unit located inside the refinery.
 - (4) If a Hydrogen Generation unit is present, calculate the Petroleum Refinery 'direct-only emissions' expressed in tonnes CO_{2e} per calendar year excluding the Hydrogen Generation unit emissions. As per (2) above, exclude from these emissions the cogeneration unit emissions, if present inside the refinery.
 - (5) Calculate the Direct Only CAN-CWB (with H₂, no Cogen) for the refinery as per the CAN-CWB Methodology using the values from (1), (2) and (3) above expressed in CAN-CWB per calendar day.
 - (6) Calculate the Direct Only CAN-CWB (without H₂ and cogeneration) by multiplying (5) and (4), divided by (2) expressed in CAN-CWB per calendar day.
 - (7) Calculate the annual Direct Only CAN-CWB (without H₂ and cogeneration) by multiplying (6) with the number of days in the year expressed in CAN-CWB per calendar year.

ON.204 Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

- (1) For FCCUs and fluid coking units, the person shall measure the following parameters:
 - (i) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
 - (ii) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
 - (iii) Weekly periodic measurements of the CO₂, CO and O₂ concentrations in the regenerator exhaust gas (or continuous measurements if the equipment necessary to make continuous measurements is already in place).
 - (iv) Daily determinations of the carbon content of the coke burned.
 - (v) The number of hours of operation.

- (vi) The measured daily or weekly values can be used to derive the minute or hourly parameters as required by the corresponding equations.
- (2) For periodic catalyst regeneration, the person shall measure the following parameters.
 - (i) The mass of catalyst regenerated in each regeneration cycle.
 - (ii) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
- (3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the person shall measure the following parameters.
 - (i) The hourly catalyst regeneration rate.
 - (ii) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
 - (iii) The number of hours of operation.
- (b) Process vents. The person shall measure the following parameters for each process vent.
 - (1) The vent flow rate for each venting event from measurement data, process knowledge or engineering estimates.
 - (2) The molar fraction of CO₂, N₂O, and CH₄ in the vent gas stream during each venting event from measurement data, process knowledge or engineering estimates.
 - (3) The duration of each venting event.
- (c) Asphalt Production. The person shall measure the mass of asphalt blown.
- (d) Sulphur Recovery. The person shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molar fraction that is based on measurements instead of the default factor or engineering estimates, the person shall conduct an annual test of the molar fraction value.
- (e) Flares and Other Control Devices. The person shall measure the following:
 - (1) If the person has a continuous flow monitor on the flare, the person shall use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If the person does not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, the person shall use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

- (2) If using the method specified in ON.203(e)(2)(i)(A), monitor the carbon content of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).
 - (3) If using the method specified in ON.203(e)(2)(i)(B), monitor the high heat value of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).
- (f) Storage Tanks. The person shall determine the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using company record or applicable plant instruments.
- (g) Wastewater Treatment. The person shall measure the following parameters.
- (1) The person shall collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (e.g., after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). The person shall collect and analyze samples for COD or BOD₅ concentration once each calendar week.
 - (2) The person shall measure the flow rate of wastewater entering anaerobic wastewater treatment process once each calendar week. The flow measurement location shall correspond to the location used to collect samples analyzed for COD or BOD₅ concentration.
 - (3) The quarterly nitrogen content of the wastewater.
- (h) Oil-Water Separators. The person shall measure the daily volume of waste water treated by the oil-water separators.
- (i) Petroleum Coke Calcining. Determine the mass of petroleum coke as required using measurement equipment used for accounting purposes including purchase records or direct measurement. Determine the carbon content of petroleum coke as using any one of the following methods.
- (1) ASTM D3176.
 - (2) ASTM D5291.
 - (3) ASTM D5373.
 - (4) Any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 5).
 - (5) The most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (j) CAN-CWB. Determine the following parameters through measurements.

- (1) “Throughput” for each of the Standard Refining Process Units identified in Appendix B of the CAN-CWB Methodology.
 - (2) “Total Input Barrels” described in Section 2.4.2 of the CAN-CWB Methodology.
 - (3) “Non-Crude Input Barrels” described in Section 2.4.3 of the CAN-CWB Methodology.
 - (4) “Exported Steam” from the refinery, net of steam originating from a cogeneration unit located inside the refinery.
 - (5) “Exported Electricity” from the refinery, net of electricity originating from a cogeneration unit located inside the refinery.
 - (6) “Imported steam” to the refinery, including steam originating from a cogeneration unit located inside the refinery.
 - (7) “Imported Electricity” to the refinery, including electricity originating from an outside source or from a cogeneration unit located inside the refinery.
- (k) Equipment used to measure the CAN-CWB parameters shall be:
- (1) calibrated according to the manufacturer’s instructions and
 - (2) maintained to achieve an accuracy of plus or minus 5%.

ON.205 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.204, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of quantity

- (b) Whenever sampling and measurement data required by ON.204 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
 - (i) Determine the sampling or measurement rate using the following Equation 200-31:

$$R = Q_{S \text{ Act}} / Q_{S \text{ Required}} \quad \text{Equation 200-31}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

$Q_{S \text{ Act}}$ = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.204

- (ii) Replace the missing data as follows,
 - (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
 - (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
 - (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns coke burn, volumetric gas flow, gas volume, number of hours of operation, quantity of bituminous product blown, quantity of crude oil and intermediate products, quantity of wastewater treated, quantity of coke, quantity of coke dust or number of vessels openings in a coking unit, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

Table 200-1 Coke burn rate material balance and conversion factors

	(kg min)/(hr dRm³%)	(lb min)/(hr dscf %)
K ₁	0.2982	0.0186
K ₂	2.0880	0.1303
K ₃	0.0994	0.0062

- K₁ Carbon burn term
- K₂ Hydrogen burn term from O₂ in Air
- K₃ Hydrogen burn equivalent in excess O₂ and carbon oxides

Table 200-2 - Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Sea, river and lake discharge	Untreated, rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Aerobic treatment plant	Treated, well maintained, some CH ₄ may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Treated, not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	Treated, CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	Treated, CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Treated, depth less than 2 metres	0.2	0 – 0.3
Anaerobic deep lagoon	Treated, depth more than 2 metres	0.8	0.8 – 1.0

For CH₄ generation capacity (B) in kg CH₄/kg COD, use default factor of 0.25 kg CH₄/kg COD.

The emission factor for N₂O from discharged wastewater (EF_{N₂O}) is 0.005 kg N₂O-N/kg-N.

MCF = methane conversion factor (the fraction of waste treated anaerobically).

COD = chemical oxygen demand (kg COD/m³).

Table 200-3 - Emission Factors for Oil/Water Separators

Separator Type	Emission factor (EF _{sep}) ^a kg NMHC/m ³ wastewater treated
Gravity type – uncovered	1.11e-01
Gravity type – covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF ^b or IAF ^c – uncovered	4.00e-03 ^d
DAF or IAF – covered	1.20e-04 ^d
DAF or IAF – covered and connected to a destruction device	0

^aEFs do not include ethane

^bDAF = dissolved air flotation type

^cIAF = induced air flotation device

^dEFs for these types of separators apply where they are installed as secondary treatment systems

ON.340 Phosphoric acid Production

ON.341 Activity Definition

For the purposes of this standard quantification method:

“Phosphoric acid production” has the same meaning as in the Regulation.

“Person” means a person that engages in phosphoric acid production.

ON.342 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.340 – ON.345, in an emission report prepared for a calendar year in respect of phosphoric acid production at a facility:

(a) CO₂ process emissions from each wet-process phosphoric acid process line (tonnes).

(b) Annual phosphoric acid production (tonnes)

ON.343 Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart Z Section 98.263.

ON.344 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance with U.S. EPA 40 CFR 98 Subpart Z Section 98.264.

ON.345 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart Z Section 98.265.

ON.70 Primary Aluminum Production

ON.71 Activity Definition

For the purposes of this standard quantification method:

“Primary aluminum production” has the same meaning as in the Regulation.

“Person” means a person that engages in primary aluminum production.

ON.72 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.70 – ON.75, in an emission report prepared for a calendar year in respect of primary aluminum production at a facility:

- (a) Perfluoromethane (CF₄), and perfluoroethane (C₂F₆) emissions from anode effects in all prebake and Søderberg electrolysis cells (tonnes).
- (b) CO₂ emissions from anode consumption during electrolysis in all prebake and Søderberg electrolysis cells (tonnes).
- (c) CO₂ emissions from on-site anode baking (tonnes).
- (d) Annual aluminum production (tonnes)

ON.73 Calculation of GHG Emissions

Quantify emissions in accordance with U.S. EPA 40 CFR 98 Subpart F Section 98.63.

ON.74 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance with U.S. EPA 40 CFR 98 Subpart F Section 98.64.

ON.75 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart F Section 98.65.

ON.210 Pulp and Paper Production

ON.211 Activity Definition

For the purposes of this standard quantification method:

“Pulp and paper production” has the same meaning as in the Regulation.

“Person” means a person that engages in pulp and paper production.

ON.212 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.210 – ON.215, in an emission report prepared for a calendar year in respect of pulp and paper production at a facility:

- (a) Annual CO₂, biogenic CO₂, CH₄, and N₂O process emissions from all recovery units and kilns combined in tonnes, as specified in ON.213.
- (b) Annual CO₂ emissions from addition of makeup chemicals (CaCO₃, Na₂CO₃) in the chemical recovery areas of chemical pulp mills.
- (c) Annual consumption of carbonate in tonnes.
- (d) Annual black liquor production in tonnes.
- (e) Annual pulp production in tonnes air dried pulp.

ON.213 Calculation of GHG Emissions

Calculate emissions from each unit (i.e., kraft or soda chemical recovery furnace, sulfite chemical recovery combustion unit, stand-alone semichemical recovery combustion unit, or kraft or soda pulp mill lime kiln) as specified under paragraphs (a) through (d) of this section. CH₄ and N₂O emissions shall be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

- (a) For kraft or soda pulp mill lime kilns, calculate fossil-fuel based CO₂ emissions from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by ON.20.
- (b) For kraft or soda pulp mill lime kilns, calculate fossil-fuel based CH₄ and N₂O emissions from direct measurement of fossil fuels consumed, default HHV, and default emission factors according to the methodology specified by ON.20.
- (c) Calculate biogenic CO₂ emissions and emissions of CH₄ and N₂O from biomass as specified under subparagraphs (1) through (3).
 - (1) For kraft or soda chemical recovery furnaces, calculate emissions using Equation 210-1:

$$Emissions = Solids \times HHV \times EF$$

Equation 210-1

Where:

- Emissions = Biogenic CO₂ emissions and emissions of CH₄ and N₂O from biomass (spent liquor solids) combustion (tonnes/year).
- Solids = Mass of spent liquor solids combusted (tonnes/year).
- HHV = Annual high heat value of spent liquor solids (mmBtu/kg).
- EF = Default emission factor for CO₂, CH₄, and N₂O from Table 210-1 (kg/mmBtu)

- (2) For sulfite or stand-alone semi-chemical or chemical recovery combustion units, calculate CO₂ emissions using Equation 210-2:

$$E_{CO_2} = 3.664 \times Solids \times CC$$

Equation 210-2

Where:

- E_{CO₂} = Biogenic CO₂ emissions from spent liquor solids combustion (tonnes/year).
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- Solids = Mass of spent liquor solids combusted (tonnes/year).
- CC = Annual carbon content of spent liquor solids (per cent by weight, expressed as a decimal fraction).

- (3) For sulfite or stand-alone semi-chemical or chemical recovery combustion units, calculate emissions of CH₄ and N₂O from biomass using Equation 210-1.

- (d) For make-up chemical use, calculate CO₂ emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO₂ and make-up chemicals using Equation 210-3:

$$CO_2 = \left(\left[M_{CaCO_3} \times \frac{44}{100} \right] + \left[M_{Na_2CO_3} \times \frac{44}{105.99} \right] \right)$$

Equation 210-3

Where:

- CO₂ = CO₂ emissions from make-up chemicals (tonnes/year).
- M_{CaCO₃} = Make-up quantity of CaCO₃ used for calendar year (tonnes/year).
- M_{Na₂CO₃} = Make-up quantity of Na₂CO₃ used for calendar year (tonnes/year).
- 44 = Molecular weight of CO₂.
- 100 = Molecular weight of CaCO₃.
- 106 = Molecular weight of Na₂CO₃.

ON.214 Sampling, Analysis, and Measurement Requirements

At least annually, determine the high heat value, annual mass and carbon content of spent liquor solids using any of the following methods. If measurements are performed more frequently than annually, then fuel properties shall be based on the average of the representative measurements made during the year.

- (a) Determine high heat values of black liquor using Technical Association of the Pulp and Paper Industry (TAPPI) T684 om-06 “Gross High Heating Value of Black Liquor”.
- (b) Determine annual mass of spent liquor solids using one of the methods specified in subparagraph (1) or (2).
 - (1) Measure mass of annual spent liquor solids using TAPPI T650 om-05 “Solids Content of Black Liquor”.
 - (2) Determine mass of annual spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit. Measure the quantity of black liquor produced each month.
- (c) Determine carbon content using one of the following methods:
 - (1) ASTM D5373;
 - (2) ASTM 5291;
 - (3) Any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 5);
 - (4) The most appropriate method published by a consensus-based standards organization; or
 - (5) If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

ON.215 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.214, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of Quantity

- (b) Whenever sampling and measurement data required by ON.214 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:

(1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:

(i) Determine the sampling or measurement rate using the following Equation 214-4:

$$R = Q_{S \text{ Act}} / Q_{S \text{ Required}} \quad \text{Equation 214-4}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

$Q_{S \text{ Act}}$ = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.214

(ii) Replace the missing data as follows,

(A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the period missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;

(B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;

(C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;

(2) When the missing data concerns the quantity of spent pulping liquor, the mass flow of spent pulping liquor, the annual production of each pulp and paper product manufactured or the quantity of carbonate material, the replacement data shall be estimated on the basis of all the data relating to the processes used.

(3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

Table 210-1 Kraft Pulping Liquor Emissions Factors for Biomass-Based CO₂, CH₄, and N₂O in (kg/mmBtu HHV)

Wood Furnish	CO₂^a	CH₄	N₂O
North American Softwood	94.4	0.030	0.005
North American Hardwood	93.7	0.030	0.005
Bagasse	95.5	0.030	0.005
Bamboo	93.7	0.030	0.005
Straw	95.1	0.030	0.005

^a Includes emissions from both the recovery furnace and pulp mill lime kiln.

ON.30 Refinery Fuel Gas Use

ON.31 Activity Definition

For the purposes of this standard quantification method:

“Refinery fuel gas use” has the same meaning as in the Regulation.

“Person” means a person that engages in refinery fuel gas use.

ON.32 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.30 – ON.35, in an emission report prepared for a calendar year in respect of refinery fuel gas use within a petroleum refinery at a facility:

- (a) Annual CO₂, CH₄, and N₂O emissions from refinery fuel gas combustion in tonnes.
- (b) Annual fuel consumption in units of standard cubic meters.
- (c) Average carbon content of each fuel used to compute CO₂ emissions.

ON.33 Calculation of Greenhouse Gas Emissions

- (a) Calculation of CO₂ Emissions. The person shall calculate daily CO₂ emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(4) of this section. Calculate the total annual CO₂ emissions from combustion of all fuel gas by summing the CO₂ emissions from each fuel gas system.
 - (1) Use a CEMS that complies with the provisions in Calculation Methodology 4 of ON.23.
 - (2) Calculate CO₂ emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001 \quad \text{Equation 30-1}$$

Where:

- CO₂ = Carbon dioxide emissions, tonnes/year.
- Fuel_i = Daily refinery fuel or flexigas combusted (Rm³) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the daily fuel combusted in kg and replace the term “MW/MVC” with “1”.
- CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
- MW = Daily sample of molecular weight of fuel (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the above Fuel_i (Rm³/kg-mole).

- = $8.3145 * [273.16 + \text{reference temperature in } ^\circ\text{C}] / [\text{reference pressure in kilopascal}]$.
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon.
- 0.001 = Conversion factor for kg to tonnes.
- n = Number of days in a year.

- (3) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary combustion in Calculation Methodologies 3 or 4 of ON.23, as appropriate for each fuel.
- (4) Where individual fuels are mixed prior to combustion, the person may choose to calculate CO₂ emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1) or (a)(2) of this section. In this case, the person shall determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO₂ emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO₂ emissions from the mixture. CO₂ emissions for each fuel stream shall be estimated using the following methods:
 - (i) For natural gas and associated gas, use the appropriate methodology specified in Calculation Methodologies 2 or 3 of ON.23.
 - (ii) For refinery fuel gas, flexigas, and low heat content gas, use the methodology in paragraph (a)(2) of this section.
- (d) Calculation of CH₄ and N₂O Emissions. The person shall use the methods specified in section ON.24 to calculate the annual CH₄ and N₂O emissions.

ON.34 Sampling, Analysis, and Measurement Requirements

- (a) Measure the fuel consumption rate daily using methods specified in ON.25(b).
- (b) Daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if there is sampling at a frequency of daily or more currently or if there is online instruments in place to monitor carbon content. Otherwise, weekly sampling and analysis of carbon content and molecular weight shall be performed. The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas shall be installed no later than January 1, 2012
- (c) Measure the carbon content for fuel gas and flexigas using either ASTM D1945 or ASTM D1946, or any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 5), or the most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

Alternatively, the results of chromatographic analysis of the fuel gas may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in a plan.

ON.35 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.34, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of Quantity

- (b) Whenever sampling and measurement data required by ON.34 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:
- (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
- (i) Determine the sampling or measurement rate using the following Equation 30-2:

$$R = Q_{S \text{ Act}}/Q_{S \text{ Required}} \qquad \text{Equation 30-2}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

$Q_{S \text{ Act}}$ = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.34

- (ii) Replace the missing data as follows,
- (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the period missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
- (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;

- (2) When the missing data concerns gas consumption, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.220 Soda Ash Production

ON.221 Activity Definition

For the purposes of this standard quantification method:

“Soda ash production” has the same meaning as in the Regulation.

“Person” means a person that engages in soda ash production.

ON.222 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.220 – ON.225, in an emission report prepared for a calendar year in respect of soda ash production at a facility:

(a) CO₂ process emissions from soda ash manufacturing line (tonnes).

(b) Annual soda ash production (tonnes)

ON.223 Calculation of GHG Emissions

Quantify emissions in accordance with EPA 40 CFR part 98.293.

ON.224 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance with U.S. EPA 40 CFR 98 Subpart CC Section 98.294.

ON.225 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with U.S. EPA 40 CFR 98 Subpart CC Section 98.295.

ON.240 Zinc Production

ON.241 Activity Definition

For the purposes of this standard quantification method:

“Zinc production” has the same meaning as in the Regulation.

“Person” means a person that engages in zinc production.

ON.242 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods ON.240 – ON.245, in an emission report prepared for a calendar year in respect of zinc production at a facility:

- (a) Annual emissions of CO₂ at the facility level (tonnes).
- (b) Annual quantities of each carbon-containing input material used (tonnes).
- (c) Carbon content of each carbon-containing input material used (tonnes C/tonne reducing agent).
- (d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used).
- (e) Annual zinc production (tonnes)

ON.243 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- (a) Determine facility CO₂ emissions using continuous emissions monitoring systems (CEMS) as specified in Calculation Methodology 4 of ON.23.
- (b) Calculate total CO₂ emissions using Equation 240-1. Specific materials that contribute less than 1 per cent of the total carbon into the process do not have to be included in the calculation using Equation 240-1.

$$E_{CO_2} = \sum_i (Q_i \times C_i) \times 3.664 \quad \text{Equation 240-1}$$

Where:

- E_{CO_2} = Annual CO₂ emissions from carbon-containing materials (tonnes);
- Q_i = Annual quantity of carbon-containing material i (tonnes);
- C_i = Carbon content of carbon-containing material i (tonnes C/tonne process input);
- 3.664 = Stoichiometric conversion factor from C to CO₂.

ON.244 Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for

accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods, or any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 5), or the most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
 - (1) For zinc-bearing materials, use ASTM E1941.
 - (2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373.
 - (3) For flux materials (i.e., limestone or dolomite), use ASTM C25.
 - (4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.
 - (i) Use an average carbon content value from samples analyzed for per cent carbon, based on monthly composites of e-waste that is riffled, ground to no less than 2 mm, split and then analyzed.
- (b) Obtain carbon content from material vendor or supplier.
- (c) The person shall measure the zinc production. Equipment used to measure the production shall be:
 - (1) calibrated according to the manufacturer's instructions and
 - (2) maintained an accuracy of plus or minus 5%.

ON.245 Procedures for Estimating Missing Data

Unavailable analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in ON.244, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of Quantity

- (b) Whenever sampling and measurement data required by ON.244 for the calculation of emissions is missing the person shall ensure that the data is replaced using the following missing data procedures:

(1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:

- (i) Determine the sampling or measurement rate using the following Equation 240-2:

$$R = Q_{S \text{ Act}}/Q_{S \text{ Required}} \quad \text{Equation 240-2}$$

Where:

R = Sampling or measurement rate that was used, expressed as a percentage

$Q_{S \text{ Act}}$ = Quantity of actual samples or measurements obtained by the person

$Q_{S \text{ Required}}$ = Quantity of samples or measurements required under ON.244

- (ii) Replace the missing data as follows,

- (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the period missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
- (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
- (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;

(2) When the missing data concerns raw material consumption, zinc production or by-product production, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

(3) For all units subject to the requirements of ON.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in EPS 1/PG/7 shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

