Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions (DRAFT)

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Ontario

Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions

Ministry of the Environment, Conservation and Parks

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Colour Coding

Blue highlighted text notes new changes to the Ontario regulation or guideline, that are not part of the current Ontario or Federal reporting requirements. Ontario adoption of federal definitions for facilities or activities are also included.

Yellow highlighted text notes the changes that were previously part of the Ontario reporting requirements which Ontario is retaining while adopting the Federal methods for calculations.

Text without any highlight notes text that are part of the federal requirements or the current Ontario reporting requirements.

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 3 of this Guideline.

Section 4 of the Guideline lists the technical reference documents referred to within the standard quantification methods.

2. Definitions

Note: MECP is considering a revised definition of “facility” in the Regulation. That revised definition is included below for consultation.

(1) Any one of the following constitutes a facility:

1. All of the following that are operated in an integrated manner to carry out a specified GHG Activity:
    - (i) Sites at which a specified GHG activity is carried out and the buildings, equipment, and other structures and stationary items located on those sites.
    - (ii) Any other sites used in conjunction with the specified GHG activity, including a quarry, tailings pond, wastewater lagoon or pond and landfill.
2. The portion of a natural gas pipeline system within Ontario that is used to transmit processed natural gas and that is upstream of a metering station.
3. The portion of a natural gas pipeline system within Ontario that is used in the local distribution of processed natural gas and that is downstream of a metering station.
4. An electricity transmission or distribution system within Ontario.

(2) If, with respect to sites or other portions that would form part of a single facility under paragraph 1 of subsection (1), there is more than one owner or operator, only those sites and portions that have at least one common owner or operator are considered to form part of the same facility.

(3) With respect to pipelines and associated installations or equipment that would form part of a single facility under paragraph 2 or 3 of subsection (1), if there is more than one owner or operator,

(a) only those pipelines and associated installations or equipment that have at least one common owner or operator are considered to form part of the same facility; and

(b) only those pipelines and associated installations or equipment that are operated in an integrated manner are considered to form part of the same facility.

(4) Two or more facilities referred to in paragraph 2 or 3 of subsection 1 (1) that would otherwise be considered to be separate facilities are considered to be a single facility if the facilities have at least one common owner or operator and are operated in an integrated manner.

(5) Any part of a public road or of a railway track that is bordered on both sides by a facility and used to carry out the facility's specified GHG activities is considered to be part of the facility.

(6) For greater certainty, buildings that are used for legal, administrative or management purposes and that are not located where an industrial activity is carried out do not form part of a facility.

(7) For the purposes of this Regulation, sites or other portions of a facility, or separate facilities, are operated in an integrated manner if any of the following occurs between them:

1. Transfer of intermediate products, final products, byproducts, byproduct fuels or other material for processing, packaging or shipping.

2. Transfer of energy, including steam, cooling media or electricity, generated at one of them and used at another, other than the transfer of common fuels directly from one to another.

"metering station" means a location in Ontario at which,

(a) the ownership or control of natural gas passes from one party to another, neither of whom is the ultimate consumer, or

(b) the pressure of a natural gas pipeline is reduced from over 200 pounds per square inch to less than 200 pounds per square inch.

For the purposes of this Guideline:

“**Act**” means the *Environmental Protection Act, R.S.O. 1990, Chapter E.19*.

"**Ammonia**" means ammonia produced through the reaction of nitrogen with hydrogen that has been produced by steam hydrocarbon reforming or gasification of solid or liquid raw material.

“**Annual electrical energy output from the cogeneration unit**” means the gross electricity generation from the cogeneration unit, expressed in gigajoules (GJ) per year

“**Annual electricity generated**” means the gross electricity generation expressed in gigawatt hours (GWh) per year.

“**Annual total energy output from the cogeneration unit**” means the sum of:

a) gross electricity generation from the cogeneration unit, expressed in gigajoules (GJ) per year, plus
b) the useful thermal energy that is generated from a cogeneration unit, expressed in gigajoules (GJ) per year.

“**Annual useful thermal energy that is generated from a combustion device and transferred**” means useful thermal energy that is generated from a combustion device and transferred to any other covered facility or non-covered facility.

“**Annual useful thermal energy output from the cogeneration unit**” means the useful thermal energy that is generated from a cogeneration unit, expressed in gigajoules (GJ) per year.

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

"**Beans and Seeds Crushed**" means canola and soybeans crushed to produce finished oilseeds products for human or animal consumption.

“**Beverage Alcohol**” means ethanol produced by distillation for use in the production of alcoholic beverages.

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

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

“**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.

“**Canada’s Greenhouse Gas Quantification Requirements**” **or** “**GGQR**” means the document entitled “Canada’s Greenhouse Gas Quantification Requirements”, Greenhouse Gas Reporting Program, published by Environment and Climate Change, as amended from time to time.

“**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.

“**Citric acid**” means citric acid produced by fermentation at a facility.

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

“**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 Processing Association of Canada (GPAC), GPA Midstream Association, the Canadian General Standards Board, GPSA Midstream Suppliers , the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), the North American Energy Standards Board (NAESB), International Organization for Standardization (ISO), Environment and Climate Change Canada, United States Environmental Protection Agency, British Standards 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.

“**Corn germ processed**” means corn germ processed to expel and refine corn oil at a facility

“**Corn milled**” means corn wet-milled at a facility.

“**Director**” has the same meaning as in 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.

“**Drivers**” means an electric motor, reciprocating engine or turbines used to drive a compressor.

“**dSm^3**” 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 an 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 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.

“**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;

“**Finished Oilseed Products**” means product derived from oilseeds for human or animal consumption

“**Finished product**(**s**)” means the production of pulp, paper or other product derived directly from pulp or pulping process.

a) in the case of pulp:
    i. if the moisture content exceeds 10%, the weight of the pulp after it is adjusted so that its moisture content does not exceed 10%, or
    ii. if the moisture content is equal to or less than 10%, the weight of the pulp without adjustment
b) in the case of a product derived directly from pulp or the pulping process, the weight of the product or, if it has been machine dried, its weight after it has been dried.

“**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.

“**Fumaric Acid**” means fumaric acid produced for use as an industrial or food additive.

“GGQM” means the quantification methods in GGQR.

“**GJ**” means gigajoules or billion joules.

“**Glucose**” means glucose produced from corn wet-milling.

“**Gold produced**” is defined as the production of gold from the mining or milling of ore.

“**Grey cement**” means cement that is produced from clinker, that contains more than 0.5% by weight of ferric oxide.

“**Guideline**” has the same meaning as in the Regulation.

“**Gypsum panels**” means gypsum 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.

“**Industrial ethanol**” means all distilled ethyl alcohol (C_2H_5OH) 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.

“**Intermediate clinker**” means clinker that is produced at the covered facility and not mixed at the covered facility with gypsum and limestone to produce grey cement.

“**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.

“**LABS**” refers to Litres of absolute alcohol (excluding water, additives and denaturants).

“**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.

“**Malic Acid**” means malic acid produced for use as an industrial or food additive.

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

“**Megawatt hours of work**” means the sum of production of drivers and electricity generation expressed in megawatt hours at the facility.

“**Mined material**” is defined as the mass of naturally occurring material that is extracted from the ground for the purpose of gold mining activities.

“**Mineral Wool**” means fibers produced from basalt rock and slag melted in a cupola at the facility but does not include glass wool.

“**MJ**” means mega joules or one million joules.

“**MPMD**” means 2-methylpentamethylenediamine

“**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).

“**Nepheline syenite**” means production of nepheline syenite from the mining or milling of nepheline ore where nepheline syenite is an inert granite-like rock which contains no free-silica.

“**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 that is 30 to 70 per cent in strength produced using the catalytic oxidation of ammonia.

“**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.

“**Nylon Resins**” means resins of Nylon 6 or Nylon 6,6

“**Nylon Fibres**” means fibres of Nylon 6 or Nylon 6,6

“**Ontario Regulation 143/16**” has the same meaning as in the Regulation.

“**Ontario Regulation 452/09**” has the same meaning as in the Regulation.

“**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).

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

“**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**” means blast furnace gas or coke oven gas from a blast furnace or coke oven located at a facility at which iron and steel production is engaged in.

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

“**Products from Steam Cracker**” means hydrogen gas, ethylene, propylene, butadiene and pyrolysis gas that are produced from steam cracking.

“**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.

“**Propane and butane**” means combined volume of propane and butane at a temperature of 15 degrees Celsius and at an equilibrium pressure.

“**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 processed**” means sugar used as a raw material that is further refined or melted.

"**Refinery Feed**" means feedstock used to produce lubricant base oil products.

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

“**Rm^3**” 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. 390/18 made under the Act.

“**Seamless steel tubes**” means seamless steel tubes produced from the rotary hearth furnace at a facility.

“**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 "**Sm^3**" 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.

"**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.

"**Urea**" means urea liquor produced at a facility which produces ammonia.

"**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.

"**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.

"**White cement**" means cement that is produced from clinker, that contains 0.5% or less by weight of ferric oxide.

3. Standard Quantification Methods

Where the Regulation requires the use of a standard quantification method, the methods listed in the following table shall be used.

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Adipic acid production	ON.50 - ON.55	1
Aluminum production	ON.70 – ON.75	2
Ammonia production	ON.80 – ON.85	3
Base metal production	ON.260 – ON.265	4
Carbonate use	ON.180 –ON.185	5
Cement production	ON.90 – ON.95	6
Coal storage	ON.100 – ON.105	7
Electricity generation	ON.40 – ON.45	8
Electricity importation	ON.60 – ON.67	9
Fuel combustion and flaring	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
Iron and steel and ferroalloy productions	ON.150 – ON.155	14
Lime production	ON.170 – ON.175	15
Magnesium production	ON.290 – ON.295	16
Nitric acid production	ON.310 – ON.315	17
Operation of equipment for a transmission system or a distribution system (electricity)	ON.230 – ON.235	18
Operation of equipment related to natural gas	ON.350 – ON.357	19
Other emissions	ON.190 - ON.195	20
Petrochemical production	ON.300 - ON.305	21
Petroleum refining	ON.200 – ON.205	22

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Phosphoric acid production	ON.340 – ON.345	23
Pulp and paper production	ON.210 – ON.215	24
Soda ash production	ON.220 – ON.225	25
Wastewater processing	ON.270 – ON.275	26

4. 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

Reference Title
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.
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.

Reference Title
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
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

Reference Title
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
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 and Climate Change Canada, “Reference method for source testing quantification of carbon dioxide releases by continuous emission monitoring systems from thermal power generation.” Report En14-46/1-2012E-PDF
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.
Technical Association of the Pulp and Paper Industry (TAPPI) T684 “Gross High Heating Value of Black Liquor”

Reference Title
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

5. Applicability and Transition

A person required by the Regulation to use a standard quantification method to quantify GHG emissions for an activity engaged in in 2019 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, Ontario Regulation 143/16, or Ontario Regulation 452/09, 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, the Guideline as incorporated into Ontario Regulation 143/16 or the Guideline for Greenhouse Gas Emissions Reporting as incorporated into Ontario Regulation 452/09 that was in effect for the year that was the subject of the original report.

6. Production Parameters

Where the *GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit* (the “EPS Methodology”), requires the use of a production parameter or a stringency factor parameter in a calculation, the person required to do the calculation shall report the production parameter and the stringency factor parameter in accordance with this section.

A person shall set out the following information, where applicable, calculated for the calendar year, in an emission report prepared for a calendar year in respect of the applicable production parameters and parameters used to calculate stringency factor at a facility. For greater certainty, all production parameters are those produced at the facility and do not include production parameters produced elsewhere unless otherwise specified.

6.1 Sector Performance Standards Production Parameters

1) Intermediate clinker produced (expressed in tonnes)

2) Grey cement produced from clinker produced at the covered facility (expressed in tonnes), as well as the tonnes of clinker, gypsum and limestone that the grey cement contains, set out separately
3) CAN-CWB per calendar year
4) Coke produced from a coke oven (expressed in tonnes)
5) Iron produced from a blast furnace (expressed in tonnes)
6) Steel produced from a basic oxygen furnace (expressed in tonnes)
7) Steel produced from an electric arc furnace (expressed in tonnes)
8) Hydrogen produced from using steam hydrocarbon reforming or partial oxidation of hydrocarbon (at a petroleum refinery or other types of facilities) (expressed in tonnes)
9) Gold produced (expressed in kilograms)
10) Nitric acid produced (expressed in tonnes)
11) Ammonia produced (expressed in tonnes)
12) Urea produced (expressed in tonnes)

6.2 Facility Specific Performance Standard Production Parameters

13) Mined material at the facility with Federal GHG Reporting ID G10765 (expressed in million tonnes)
14) Nepheline syenite produced at the facility with Federal GHG ID G10902 (expressed in tonnes).
15) Fuel ethanol produced (expressed in kilolitres of absolute ethanol)
16) Industrial ethanol produced (expressed in kilolitres of absolute ethanol)
17) Brick or other products made from clay or shale using a kiln (expressed in tonnes)
18) Mineral wool insulation produced (expressed in tonnes)
19) Glass produced (expressed in tonnes)
20) Gypsum panels produced (expressed in tonnes)
21) White cement produced from clinker produced at the covered facility (expressed in tonnes) as well as the tonnes of clinker, gypsum and limestone that the white cement contains, set out separately
22) Finished product(s) produced (expressed in tonnes)
23) Megawatt hours of work (expressed in MWh)
24) Refinery feed at the facility with GHGID 1111 (expressed in kilolitres)
25) Ethylene produced at the facility with GHGID1100 (expressed in tonnes)
26) Polyethylene produced (expressed in tonnes)
27) Carbon black produced (expressed in tonnes)
28) Styrene produced (expressed in tonnes)
29) Nylon resins produced (expressed in tonnes)
30) Nylon fibres produced (expressed in tonnes)
31) Products from steam cracker at the facilty with GHGID 1073 (expressed in tonnes)
32) Products not from steam cracker at the facility with GHGID 1073 (expressed in tonnes)

33) High calcium lime produced (expressed in tonnes)
34) Cal 85 produced (expressed in tonnes)
35) Dolimitic lime produced (expressed in tonnes)
36) Double burnt lime produced (expressed in tonnes)
37) Iron coated dolime produced (expressed in tonnes)
38) Propane and Butane produced at the facility with GHGID 1113 (combined volume expressed in cubic metres)
39) Finished oilseed product(s) produced (expressed in tonnes)
40) Beans and seeds crushed at the facility with GHGID 1016 (expressed in tonnes).
41) Beverage ethanol produced (expressed in kiloLABS)
42) Raw sugar processed (expressed in tonnes)
43) Malic acid produced (expressed in tonnes)
44) Fumaric Acid produced (expressed in tonnes)
45) Used Oil Feed produced at the Facility with GHGID 1122 (expressed in kilolitres)
46) Hot rolled steel produced (expressed in tonnes)
47) Seamless steel tubes produced (expressed in tonnes)
48) Corn milled (expressed in tonnes of air dried corn milled)
49) Corn germ processed (expressed in tonnes)
50) MPMD produced (expressed in tonnes)
51) Glucose produced (expressed in tonnes)
52) Citric acid produced (expressed in tonnes)

6.3 Electricity Generation, Useful Thermal Energy Transferred, Cogeneration Production Parameters

53) Annual electricity generated, used in Formula 3.1.2-1 of the EPS Methodology (expressed in GWh and in GJ)
54) Fraction of energy input that is not biomass used in Formula 3.1.2-1 of the EPS Methodology.
55) Annual useful thermal energy that is generated from a combustion device and transferred, used in Formula 3.1.3-1 of the EPS Methodology (expressed in GJ)
56) Fraction of energy input that is not biomass used in Formula 3.1.3-2 of the EPS Methodology.
57) Annual total energy output from the cogeneration unit, used in Formula 3.1.4-1 of the EPS Methodology (expressed in GJ)
58) Fraction of energy input that is not biomass used in Formula 3.1.4-2 of the EPS Methodology.
59) Annual electrical energy output from the cogeneration unit used in Formula 3.1.4-3 of the EPS Methodology (expressed in GJ), excluding the electrical output from the cogeneration unit inside a petroleum refinery if the ratio of electricity output (in GJ) to the total energy input (in GJ) of the cogeneration unit is less than 5%.

60) Annual useful thermal energy output from the cogeneration unit used in Formula 3.1.4-3 of the EPS Methodology (expressed in GJ), excluding the useful thermal energy output from the cogeneration unit inside a petroleum refinery if the ratio of electricity output (in GJ) to the total energy input (in GJ) of the cogeneration unit is less than 5%.
61) Thermal energy transferred used in Formula 3.1.5-1 of the EPS Methodology (expressed in GJ)

6.4 Energy Use and Mobile Equipment Production Parameters

62) Energy input used in Formula 3.1.7-2 (expressed in GJ)
63) For each type of fuel used in Formula 3.1.7 -3:
    a. Type of fuel used (i.e., the name of the fuel)
    b. Volume of fuel used (expressed in kilolitres)
    c. Energy input for each type of fuel (expressed in GJ)
64) Energy input used in Formula 3.1.8-1:
65) For each type of fuel used in Formula 3.1.8 -3:
    a. Type of fuel used (i.e., the name of the fuel)
    b. Volume of fuel used (expressed in kilolitres)
    c. Energy input for each type of fuel (expressed in GJ)

6.5 Stringency Factor Parameters

66) Energy Input from all biomass fuel used at the facility (expressed in GJ)
67) Total energy input from all fuel used at the facility, including biomass fuels (expressed in GJ)
68) Annual electrical energy output from the cogeneration unit used in Formula 4.3-1 of the EPS Methodology (expressed in GJ)
69) Annual total energy input to the cogeneration unit used in Formula 4.3-1 of the EPS Methodology (expressed in GJ)

6.6 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for Production Parameters are the same as those required for the measurement of production quantity and material usage in the applicable subsection entitled Sampling, Analysis and Measurement Requirements under each Standard Quantification Method. Where there are no requirements for production or material use under the applicable Standard Quantification Method, the person may use the following method:

(1) Equipment used to measure the production quantity and material usage 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%.

6.7 Procedures for Estimating Missing Production Parameter Data

Determination of Production Parameter quantity

(a) Whenever sampling, measurement, financial, purchase records, accounting records, or any other data required for the determination of a production parameter 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 6-1:

$$R_p = Q_{PAct}/Q_{PRequired} \qquad \textbf{Equation 6-1}$$

R_p = valid production record that was used, expressed as a percentage
Q_{SPc} = Quantity of valid production records obtained by the person
$Q_{SPequired}$ = Quantity of production records required

(i) Replace the missing data as follows,

(A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the production record 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 production record value during the reporting period for which the calculation is made;

(C) If $0.10 < R < 0.75$: replace the missing data by the lowest production record value sampled or analyzed during the 3 preceding years;

(D) If $R < 0.10$: replace the missing data with the number that is equal to 80 per cent of the lowest production record value sampled or analyzed during the 3 preceding years.

Appendices

ON.50 Adipic Acid Production

ON.51 Activity Definition

For the purposes of this standard quantification method (SQM):

“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

The person shall set out the following information, calculated for the calendar year using SQM 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 N_2O emissions from adipic acid production (tonnes).

(b) Annual adipic acid production (tonnes).

ON.53 Calculation of N_2O Emissions

(a) The person shall determine annual N_2O 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 N_2O 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 N_2O 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 N_2O 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:

$$EF_{N2O} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.826 \times 10^{-6} * Q}{P}}{n}$$ **Equation 50-1**

$$EF_{N2O} = \frac{C_{N2O} * 1.826 \times 10^{-6} * Q}{P}$$ **Equation 50-1a**

Where:

EF_{N2O} = Average facility-specific N_2O emissions factor without using N_2O abatement technology (kg N_2O generated/tonne adipic acid produced).

C_{N2O} = 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/dSm^3-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 (dSm^3/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 N_2O abatement technology used at the facility. The abatement factor is calculated for each adipic acid facility according to Equation 50-2 of this section.

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

Where:

AF = Abatement factor of N_2O 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 N_2O 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 N_2O abatement is operating.

(g) The person shall calculate annual adipic acid production process emissions of N_2O 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 N_2O abatement, according to Equation 50-3 of this section:

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

Where:

N_2O = Annual N_2O mass emissions from adipic acid production (tonnes).

EF_{N2Oi} = Facility-specific N_2O emissions factor for the period without abatement technology (kg N_2O generated/tonne adipic acid produced).

P_{ai} = Adipic acid produced in the period (tonnes).

DF_i = Destruction efficiency of N_2O abatement technology in the period (abatement device destruction efficiency, per cent of N_2O removed from air stream).

AF_i = Abatement factor of N_2O 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_{N2Oi}, 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 4),

(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 N_2O 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 N_2O 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:

$$R = Q_{SAct}/Q_{SRequired} \qquad \textbf{Equation 50-4}$$

R = Sampling or measurement rate that was used, expressed as a percentage
Q_{SAc} = 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 “Reference method for source testing quantification of carbon dioxide releases by continuous emission monitoring systems from thermal power generation” shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

ON.70 Aluminum Production

ON.71 Activity Definition

For the purposes of this standard quantification method (SQM):

“Primary aluminum production” has the same meaning as in the Regulation.

Proposed activity definition in the regulation - *“Aluminum production”* means the production of aluminium through primary processes that are used to manufacture aluminium from alumina, including electrolysis in prebake and Søderberg cells, anode and cathode baking for prebake cells, and green coke calcination.

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

ON.72 Greenhouse Gas Reporting Requirements

(a) The person shall set out the following information, calculated for the calendar year using SQM ON.70 – ON.75, in an emission report prepared for a calendar year in respect of aluminum production at a facility.

(b) Report the

(1) total annual quantity of CO_2 emissions from prebaked anode consumption, expressed in tonnes (t);
(2) annual anode consumption, expressed in tonnes of anodes/tonnes of liquid aluminium production;
(3) annual sulphur content of prebaked anodes, expressed in kilograms of S/kilograms of prebaked anodes; and
(4) annual ash content of prebaked anodes, expressed in kilograms of ash/kilograms of prebaked anodes.

(c) Report the

(1) total annual quantity of CO2 emissions from anode consumption from Søderberg electrolysis cells, expressed in tonnes (t);
(2) total annual quantity of cyclohexane-soluble matter emissions, expressed in tonnes (t), or the International Aluminium Institute factor used, expressed in kilograms of CSM/tonnes of liquid aluminium;
(3) total annual anode paste consumption, expressed in tonnes of paste/tonnes of liquid aluminium;
(4) annual average content of pitch or other binding agent in paste, expressed in kilograms of pitch or other binding agent/kilograms of paste;
(5) annual sulphur content in pitch or other binding agent, expressed in kilograms of S/kilograms of pitch or other binding agent;
(6) annual ash content in pitch or other binding agent, expressed in kilograms of ash/kilograms of pitch or other binding agent;

(7) annual hydrogen content in pitch or other binding agent, expressed in kilograms of H_2/kilograms of pitch or other binding agent, or the International Aluminium Institute factor used;
(8) annual sulphur content in calcinated coke, expressed in kilograms of S/kilograms of calcinated coke;
(9) annual ash content in calcinated coke, expressed in kilograms of ash/kilograms of calcinated coke; and
(10) annual carbon content in dust from Søderberg electrolysis cells, expressed in kilograms of C/kilograms of liquid aluminium, or a value of 0.

(d) Report the total annual quantity of CO_2 emissions from anode and cathode baking, expressed in tonnes (t).

(e) Report the

(1) total annual quantity of CO_2 emissions from packing material consumption, expressed in tonnes (t);
(2) annual packing material consumption, expressed in tonnes of packing material/tonnes of baked anodes or cathodes;
(3) total annual quantity of baked anodes and cathodes removed from furnace, expressed in tonnes (t);
(4) annual weighted average ash content of packing material, expressed in kilograms of ash/kilograms of packing material; and
(5) annual weighted average sulphur content of packing material, expressed in kilograms of S/kilograms of packing material.

(f) Report the

(1) total annual quantity of CO_2 emissions from coking of pitch or other binding agent, expressed in tonnes (t);
(2) total annual quantity of green anodes or cathodes put into furnace, expressed in tonnes (t);
(3) total annual quantity of baked anodes or cathodes removed from furnace, expressed in tonnes (t);
(4) annual weighted average hydrogen content of pitch or other binding agent, or the International Aluminium Institute factor used, expressed in kilograms of H2/kilograms of pitch or other binding agent;
(5) annual weighted average pitch content of green anodes or cathodes, expressed in kilograms of pitch or other binding agent/kilograms of anodes or cathodes; and
(6) total annual quantity of recovered tar, expressed in tonnes (t).

(g) Report the

(1) total annual quantity of CO_2 emissions from green coke calcination, expressed in tonnes (t);
(2) total annual quantity of CO_2 emissions from coke dust, expressed in tonnes (t);
(3) total annual quantity of green coke consumption, expressed in tonnes (t);
(4) otal annual quantity of calcinated coke production, expressed in tonnes (t);
(5) total annual quantity of under-calcinated coke production, expressed in tonnes (t);
(6) annual water content in green coke, expressed in kilograms of H_2O/kilograms of green coke;
(7) annual volatile materials content in green coke, expressed in kilograms of volatile materials/kilograms of green coke;
(8) annual sulphur content in green coke, expressed in kilograms of S/kilograms of green coke; and
(9) annual sulphur content in calcinated coke, expressed in kilograms of S/kilograms of calcinated coke.

(h) Report the

(1) total annual quantity of CF_4 emissions from anode effects, expressed in tonnes (t);
(2) annual slope, if using the slope method, by a series of pots, expressed in tonnes of CF4/tonnes of liquid aluminium/anode effect minute/pot-day/year;
(3) annual anode effect duration, if using the slope method, expressed in anode effect minutes/pot-day calculated per year and obtained by multiplying the anode effects frequency, in number of anode effects per pot-day, by the average duration of anode effects in minutes;
(4) overvoltage coefficient, if using the overvoltage coefficient method, expressed in tonnes of CF_4/tonnes of liquid aluminium/millivolt;
(5) annual anode effect overvoltages, if using the overvoltage coefficient method, expressed in millivolts/pot;
(6) current efficiency of the aluminium production process, if using the overvoltage coefficient method, expressed as a fraction; and
(7) method used to determine the quantities reported under paragraph (a).

(i) Report the

(1) total annual quantity of C_2F_6 emissions, expressed in tonnes (t); and
(2) weight fraction of C_2F_6 to CF_4 or selected from Table 5-2, expressed in kilograms of C_2F_6/kilograms of CF_4.

(j) Report the total annual quantity of emissions from SF_6 used as a cover gas, expressed in tonnes (t).

(k) Report the total annual quantity of liquid aluminium production, expressed in tonnes (t).

ON.73 Calculation of GHG Emissions

(a) Quantify emissions using the GGQM in section 5A of the GGQR.

(b) Any person subject to this method who operates a facility with stacks monitored by CEMS may use the annual emissions data from CEMS to report the emissions under sections ON.72(a) to (f). This shall not include the emissions information specified for CEMS in ON.20. The person shall indicate where CEMS is being used to calculate emissions.

ON.74 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance with section 5B of the GGQR.

ON.75 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with section 5C of the GGQR.

ON.80 Ammonia Production

ON.81 Activity Definition

For the purposes of this standard quantification method (SQM):

“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) Theperson shall set out the following information, calculated for the calendar year using SQM ON.80 – ON.85, in an emission report prepared for a calendar year in respect of ammonia production at a facility.:

(b) Report the total annual quantity of feedstock consumed, by feedstock type, expressed in

- (1) cubic metres (m3), for gaseous quantities;
- (2) kilolitres (kl), for liquid quantities; and
- (3) tonnes (t), for solid quantities.

(c) For each feedstock type used under subsection (a), report the annual weighted average carbon content expressed in

- (1) kilograms (kg) of C/kilograms (kg) of feedstock, for gaseous quantities;
- (2) kilograms (kg) of C/kilolitres (kl) of feedstock, for liquid quantities; and
- (3) kilograms (kg) of C/kilograms (kg) of feedstock, for solid quantities.

(d) Report the

- (1) total annual quantity of urea, expressed in tonnes (t);
- (2) total annual quantity of ammonia, expressed in tonnes (t);
- (3) total annual quantity of CO_2 emissions from ammonia production, expressed in tonnes (t); and
- (4) total annual quantity of CO_2 consumed in urea production, expressed in tonnes (t).

(e) Report the

- (1) total annual quantity of CO_2 recovered or captured other than the amount reported under (c)(2), expressed in tonnes (t);
- (2) Indicate if the CO2 under (d)(1) that is recovered or captured is for downstream use, on-site production or permanent storage.

ON.83 Calculating GHG Emissions

The person shall calculate and report the annual process CO_2 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 CO_2 emissions using the greenhouse gas quantification method (GGQM) in section 8.A.(1) of Canada’s Greenhouse Gas Quantification Requirements (Canada’s GGQR).

(b) Calculate and report the process CO_2 emissions using the GGQM in section 8.A.(2)(A) to (D) of GGQR.

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 may 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(s). 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 listed in paragraphs (C)(1) through (C)(9) of this section, as applicable.

(1) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

(2) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

(3) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements.

(4) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure

(5) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

(6) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(7) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke.

(8) ASTM D5373-08 Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal. .

(9) 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.

(e) If CO_2 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 (e.g sales records). The person shall document the procedures used.

(f) The person shall measure the ammonia produced using equipment that shall be:

(1) calibrated according to the manufacturer’s instructions; and

(2) maintaining an accuracy of plus or minus 5%.

ON.85 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with section 8C of GGQR.

ON.260 Base Metal Production

ON.261 Activity Definition

For the purposes of this standard quantification method (SQM):

Proposed activity definition in the regulation: “Base Metal Production” means “the production of copper, nickel, zinc, lead or cobalt base metals through one of the following:

1. Using smelting or refining processes to recover the base metals primarily from ore.
2. Recovery of the base metals from recycled material or other feedstock that is not ore.

“Person” means a person that engages in base metal production.

ON.262 Greenhouse Gas Reporting Requirements

(a) A person shall set out the following information, calculated for the calendar year using SQM ON.260 – ON.265, in an emission report prepared for a calendar year in respect of base metal production at a facility.

(b) Total annual CO_2 emissions from base metal production, by type of base metal (tonnes).

(c) Total annual quantities of carbon containing process input material (e.g., flux reagents, reducing agents or electrode consumption) by material type (tonnes).

(d) Annual weighted average carbon content of carbon-containing process input (e.g., flux reagents, reducing agents or electrode consumption) by material type (tonnes carbonate/tonnes of carbon containing process input material).

(e) Total annual quantity of carbon-containing process output material, by material type, (tonnes).

(f) Annual weighted average carbon content of carbon-containing process output, by material type (tonnes of C/tonnes of material).

(g) Total annual quantity of individual base metal or nickel matte produced, by type (tonnes).

ON.263 Calculation of CO_2 Emissions

Calculate total CO_2 emissions as specified in paragraph (a) or (b) of this section:

(a) Determine facility process CO_2 emissions from base metal production using the greenhouse gas quantification methods (GGQM) in section 13.A.(1) of GGQR.

(b) Calculate CO_2 process emissions from base metal production using the GGQM in section 13.A.(2) of GGQR.

ON.264 Sampling, Analysis, and Measurement Requirements

(a) 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.

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

(c) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following:

(1) the methods in section 13.B.(1) of GGQR.

(2) any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 4);

(3) the most appropriate method published by a consensus-based standards organization, if such a method exists orif 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) Obtain carbon content of the materials, including carbon electrodes, from the vendor or supplier.

ON.265 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with section 13.C of the GGQR.

ON.180 Carbonate Use

ON.181 Activity Definition

For the purposes of this standard quantification method (SQM):

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

(b) Annual CO_2 emissions from miscellaneous carbonate use (tonnes).

(c) 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.

(d) 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 CO_2 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 CO_2 using calcination fractions with Equation 180-1 of this section.

$$E_{CO2} = \sum_{i=1}^{n} \left(M_i \times EF_i \times F_i \right) \quad \textbf{Equation 180-1}$$

Where:

E_{CO2} = Annual CO_2 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 CO_2/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 CO_2 using actual mass of output carbonates with Equation 180-2 of this section.

$$E_{CO2} = \left[\sum_{k=1}^{m} \left(M_k \times EF_k \right) - \sum_{j=1}^{n} \left(M_j \times EF_j \right) \right]$$

Equation 180-2

Where:

E_{CO2} = Annual CO_2 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 CO_2/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 CO_2/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 4);

(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:

$$R = Q_{SAct}/Q_{SRequired}$$ **Equation 180-3**

R = Sampling or measurement rate that was used, expressed as a percentage
Q_{SAc} = 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 “Reference method for source testing quantification of carbon dioxide releases by continuous emission monitoring systems from thermal power generation” shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

Table 180-1—CO_2 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_2CO_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 (SQM):

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

Proposed activity definition in the regulation - “cement production” means the manufacture of portland, ordinary portland, masonry, pozzolanic or other hydraulic cements.

“CKD” means cement kiln dust.

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

ON.92 Greenhouse Gas Reporting Requirements

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

(b) Total annual quantity of CO_2 emissions from clinker production, expressed in tonnes.

(c) Total monthly quantity of clinker, expressed in tonnes (t);

(d) Monthly plant-specific emission factor of clinker, expressed in tonnes of CO_2/tonnes of clinker;

(e) Monthly calcium oxide (CaO) content of clinker, expressed in tonnes of CaO/tonnes of clinker;

(f) Monthly magnesium oxide (MgO) content of clinker, expressed in tonnes of MgO/tonnes of clinker;

(g) Monthly non-calcined calcium oxide (CaO) content of clinker, expressed in tonnes of CaO/tonnes of clinker;

(h) Monthly non-calcined magnesium oxide (MgO) content of clinker, expressed in tonnes of MgO/tonnes of clinker;

(i) Monthly quantity of non-carbonate raw materials entering the kiln, expressed in tonnes (t);

(j) Total annual quantity of CO_2 emissions from organic carbon oxidation, expressed in tonnes (t);

(k) Total annual quantity of raw material consumption, expressed in tonnes (t);

(l) Annual weighted average carbon content in raw material consumption, expressed in tonnes of C/tonnes of raw material consumption;

(m) Total annual quantity of CO_2 emissions from cement kiln dust (CKD) not recycled back to the kiln, expressed in tonnes (t);

(n) Total quarterly quantity of CKD not recycled back to the kiln, expressed in tonnes (t);

(o) Quarterly plant-specific emission factor of CKD not recycled back to the kiln, expressed in tonnes of CO_2/tonnes of CKD.

(p) Quarterly calcium oxide (CaO) content of CKD not recycled back to the kiln, expressed in tonnes of CaO/tonnes of CKD;

(q) Quarterly magnesium oxide (MgO) content of CKD not recycled back to the kiln, expressed in tonnes of MgO/tonnes of CKD;

(r) Quarterly non-calcined calcium oxide (CaO) content of CKD not recycled back to the kiln, expressed in tonnes of CaO/tonnes of CKD; and

(s) Quarterly non-calcined magnesium oxide (MgO) content of CKD not recycled back to the kiln, expressed in tonnes of MgO/tonnes of CKD.

(t) A person subject to this SQM who operates a facility with stacks monitored by CEMS may use the annual emissions data from CEMS to report the emissions and production information under paragraphs (a), (i), and (l). This shall not include the emissions information specified for CEMS in ON.20. The person shall indicate where CEMS is being used to calculate emissions.

ON.93 Calculation of GHG Emissions from Kilns

(a) Calculate CO_2 emissions using using the greenhouse gas quantification methods (GGQM) in section 4.A of Canada’s Greenhouse Gas Quantification Requirements (GGQR).

ON.94 Sampling, Analysis, and Measurement Requirements

(a) Sampling, analysis and measurement requirements for this activity shall be done in accordance with section 4B of the GGQR. The monthly plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in clinker may also be determined using one of the following:

  (1) Any of the applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 4);

  (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) 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

(c) 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

Missing data requirements for this activity shall be estimated in accordance with section 4C of the GGQR.

ON.100 Coal Storage

ON.101 Activity Definition

For the purposes of this standard quantification method (SQM):

“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) The person shall set out the following information, calculated for the calendar year using SQM ON.100 – ON.105, in an emission report prepared for a calendar year in respect of coal storage at a facility.

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

(1) Total CH_4 emissions.

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

(d) Source of coal purchases:

(1) Coal basin.

(2) State/province.

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

ON.103 Calculation of CH_4 Emissions

Calculate fugitive CH_4 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 CH_4 emissions using Equation 100-1 and Table 100-1.

(b) For coal purchased from Canadian sources, calculate fugitive CH_4 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.

$$CH_4 = \sum_i \left(PC_i \times EF_i\right) \times 0.6772 \ / \ 1{,}000 \qquad \textbf{Equation 100-1}$$

Where:

CH_4 = Fugitive emissions from coal storage piles for each coal origin category *i*, (tonnes CH_4 per year);

PC_i = Purchased coal for each coal origin category *i* (tonnes per year);

EF_i = Default CH_4 emission factor for each coal origin category *i* specified by location and mine type from which coal originated, provided in Table 100-2 (m^3 CH_4 per tonne of coal);
0.6772 = Methane conversion factor to convert m^3 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 (CH_4 m^3 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
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Table 100-2. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 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

ON.40 Electricity and Heat Generation

ON.41 Activity Definition

For the purposes of this standard quantification method (SQM):

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

Proposed activity definition in the regulation: “Electricity and heat generation” means the operation of any combustion device that combusts solid, liquid or gaseous fuels for the purpose of generating electricity or useful heat or steam, excluding the operation of portable or emergency generators with a nameplate capacity less than 50 kilowatts or that generate less than 2 MWh in a year.

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

ON.42 Greenhouse Gas Reporting Requirements

(a) The person shall set out the following information, calculated for the calendar year using SQM ON.40 – ON.45, in an emission report prepared for a calendar year in respect of electricity generation at a facility. For fuel combustion and flaring emissions from electricity generation, the person shall report using ON.20.

(b) Total annual quantity of CO_2 emissions from acid gas scrubbing, expressed in tonnes (t).

(c) Total annual consumption of limestone or other sorbent, by sorbent type, expressed in tonnes (t).

ON.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. The person shall calculate CO_2 emissions from electricity and heat generation using ON.23.

(b) Calculation of CH_4 and N_2O Emissions. The person shall calculate CH4 and N2O emissions from electricity generation using ON.24.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. The person that uses acid gas scrubbers or adds an acid gas reagent to the combustion unit shall calculate CO_2 emissions from fuel combustion using the GGQM in section 7.C of GGQR.

ON.44 Sampling, Analysis, and Measurement Requirements

(a) A person that is required to monitor fuel consumption pursuant to this SQM or is using CEMS shall do so in accordance with ON.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. A person that is required to use acid gas scrubbers is required to measure the parameters required in section 7.D(2) of GGQR.

ON.45 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with section 7.E of the GGQR.

ON.60 Electricity Importation

ON. 61 Activity Definition

“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 who engages in electricity importation.

“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).

“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.

“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;

  (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.65.

“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 SQM ON.60– ON.65, in the report prepared for a calendar year in respect of electricity importation.

(b) Annual quantity of specified and unspecified imported electricity used in the calculations contained in ON.63 and ON.64, expressed in MWh.

(c) The following information for each specified electricity generating facility from which the electricity importer imports electricity:

  (1) The facility name;

(2) The facility ID;

(3) If applicable, the electricity generating unit ID;

(4) Annual scheduled quantity of specified imported electricity used in ON.63, expressed in MWh; and

(5) Annual scheduled quantity of specified imported electricity wheeledthrough Ontario, expressed in MWh.

(d) Report the following information for each balancing authority area from which unspecified electricity originated:

(1) The name of the balancing authority area;

(2) Annual scheduled quantity of unspecified imported electricity used in ON.64, expressed in MWh; and

(3) Annual scheduled quantity of unspecified imported electricity wheeled through Ontario, expressed in MWh.

ON.63 Calculation of Specified Imported Electricity

The electricity importer shall use Equation 60-1 to calculate the amount of specified imported electricity imported in the year. All imported electricity that meets the definition of specified imported electricity must be reported using this calculation.

$$MWh_s = \sum_{i=1}^{n}[MWh_{total_i} - MWh_{wheel_i}]$$

Equation 60-1

Where:

MWh_s = Annual Scheduled quantity of specified 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_j} = 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.

ON.64 Calculation of Unspecified Imported Electricity

The electricity importer shall use Equation 60-2 to calculate the unspecified imported electricity from each source balancing authority area that sinks in Ontario.

$$MWh_u = \sum_{i=1}^{n} \sum_{j=1}^{n} [MWh_{total\_ij} - MWh_{wheel_{ij}}]$$

Equation 60-2

Where:

MWh_u = Annual Scheduled quantity of unspecified imported electricity imported into Ontario by the electricity importer, expressed in MWh.

MWh_{total_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, expressed in MWh.

MWh_{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.65 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.20 Fuel Combustion and Flaring

ON.21 Activity Definition

For the purposes of this standard quantification method (SQM):

Proposed activity definition in the regulation "Fuel combustion and flaring " means

1) the combustion of fuels for the purpose of providing useful heat and work from boilers, combustion turbines, engines, incinerators, process heaters, on-site transportation equipment and other combustion device.
2) the controlled releases of gases from industrial processes by means of the combustion of a gas or liquid stream produced at the facility, the purpose of which is not to produce useful heat or work.

"On-Site Transportation Emissions" means releases from machinery used for the transport or movement of substances, materials, equipment or products that are used in the production process at an integrated facility. This includes releases from vehicles without public road licences.

"Person" means a person that engages in fuel combustion and flaring.

ON.22 Greenhouse Gas Reporting Requirements

(a) The person shall set out the following information, calculated for the calendar year using SQM ON.20 – ON.26, in an emission report prepared for a calendar year in respect of fuel combustion or flaring at a facility.

(b) Any person subject to this SQM and whose facility is classified under NAICS 221112 shall use ON.20 to report the total annual quantity, expressed in tonnes (t), of CO_2, CH4 and N2O emissions, by fuel type and source, from

(1) each electricity generating unit;

(2) heat and steam generation;

(3) all other stationary fuel combustion;

(4) on-site transportation; and

(5) flaring.

(c) Any person that is not subject to section (a) above shall report the total annual quantity, expressed in tonnes (t), of CO_2, CH4 and N_2O emissions, by fuel type and source, from

(1) electricity generation;

(2) heat and steam generation;

(3) all other stationary fuel combustion;

(4) on-site transportation; and

(5) flaring.

(d) Any person subject to this SQM shall report the methods used to quantify each greenhouse gas under subsections (a) and section (b) of this section, by fuel type and source.

(e) Any person subject to this SQM who operates a facility with stacks monitored by CEMS may use the annual emissions data from the CEMS at the facitliy to report the total emissions of CO_2, CH4 and N_2O. The person shall report their fuel information by fuel type, in accordance with subsections (e) and (f) below.

(f) Any person subject to this SQM shall, for each fuel used under subsections (a) and (b) report the

(1) gaseous quantities, expressed in cubic metres (m3) or in megajoules (MJ);

(2) solid quantities, expressed in tonnes (t), for coal by rank and by country, province and state; and

(3) liquid quantities, expressed in kilolitres (kl) or in megajoules (MJ).

(g) Any person subject to this SQM shall, for each fuel used under subsections (a) and (b), report the annual measured

(1) higher heating value calculated using Equation 2-26 in section 2 of Canada’s GGQR, expressed in megajoules (MJ) higher heating value per unit of fuel consumed for all methods, except when applying Equation 2-2, Equation 2-4, Equation 2-11, Equation 2-19 or Equation 2-21;

(2) carbon content calculated using Equation 2-27 in section 2 of GGQR, expressed in kilograms of carbon per unit of fuel consumed, when using CEMS or the variable fuels or flaring methods (except when applying Equation 2-9, Equation 2-11, Equation 2-20 and for fuels identified in Table 2-3);

(3) temperature, expressed in degrees Celsius (°C) and pressure, expressed in kilopascals (kPa), for gaseous quantities;

(4) moisture content, expressed as a percentage (%), for solid quantities; and

(5) CH4 and N_2O emission factors, when using the facility-specific emission factors measured directly or provided by the fuel supplier or equipment manufacturers, expressed in grams per unit of fuel.

(h) Any person subject to this SQM shall, for each fuel used under subsections (a) and (b), report the default CO_2, CH4 and N_2O emission factors, when using values presented in Table 2-1 to Table 2-11 and in Equation 2-20, Equation 2-22 and Equation 2-23 of GGQR.

(i) Any person subject to this SQM shall report, for each fuel, the combustion oxidation factor when applied and provide supporting documentation used in its derivation.

(j) Any person subject to this SQM shall, for steam used to quantify emissions under subsections (a) and (b) above, report the

(1) steam quantities expressed in tonnes (t);

(2) quantity and type of each biomass fuel combusted expressed in tonnes (t);

(3) CO_2, CH4 and N_2O emission factors expressed in kilograms of CO_2, CH4 and N_2O/megajoules (MJ) of steam or kilograms of CO_2, CH4 and N_2O /tonnes (t) of steam; and

(4) measured temperature, expressed in degrees Celsius (°C), the measured pressure expressed in kilopascals (kPa) and the ratio of the boiler's design rated heat input capacity to its design rated steam output capacity, expressed in megajoules (MJ)/tonnes of steam, if using the steam default emission factor method.

(k) Any person subject to this SQM and whose facility is classified under NAICS 221112 shall report the annual quantities of

(1) gross electricity generated on-site by each electricity generating unit, expressed in megawatt hours (MWh);

(2) electricity sold off-site, expressed in megawatt hours (MWh);

(3) electricity lost on-site, expressed in megawatt hours (MWh); and

(4) electricity purchased, expressed in megawatt hours (MWh).

(l) Any person subject to this SQM who is not subject to section (a) above shall report the annual quantities of

(1) gross electricity generated on-site, expressed in megawatt hours (MWh);

(2) electricity sold off-site, expressed in megawatt hours (MWh);

(3) electricity lost on-site, expressed in megawatt hours (MWh); and

(4) electricity purchased, expressed in megawatt hours (MWh).

(m) Any person subject to this SQM shall, for heat and steam generation, report the annual quantities of

(1) gross steam and heat generated on-site, expressed in megajoules (MJ);

(2) gross steam and heat used to generate electricity on-site, expressed in megajoules (MJ);

(3) steam and heat sold off-site, expressed in megajoules (MJ);

(4) steam and heat purchased, expressed in megajoules (MJ); and

(5) steam or heat lost on-site, expressed in megajoules (MJ).

(n) Any person subject to this SQM shall submit documentation describing the methodology used, when

(1) developing equipment-specific on-site transportation emission factors, as required bysection 2.A.1a(3) or 2.B(3)(B) of GGQR;

(2) determining the mass of biomass combusted for premixed fuels containing biomass and fossil fuels, as required by section 2.A.4 of GGQR; or

(3) developing facility-specific CH4 and N_2O emission factors, as required by section 2.B(1) of GGQR.

(o) Any person subject to this SQM, who obtains from a supplier or performs fuel sampling, analysis and consumption measurement, as required in section 2.D of GGQR, shall submit a fuel quantity, carbon content and higher heating value for all sampling and measurement periods.

(p) Annual CO_2 emissions from the use of sorbent calculated in accordance with ON.23(d).

ON.23 Calculation of CO_2 Emissions

The person shall calculate the annual CO_2 emissions from fuel combustion and flaring as follows:

(a) Any person subject to this SQM is not required to report fuels and their associated emissions when the sum of CO2, CH4 and N2O emissions (excluding CO2 from biomass combustion), in CO2e., from the combustion of one or more of the fuels does not exceed 0.5% of the total facility GHG emissions from all fuels combusted (excluding CO2 from biomass combustion).

(b) Calculate CO_2 emissions from fuel combustion using the GGQM in section 2.A of GGQR.

(c) Calculate CO_2 emissions from flares using the GGQM in section 2.C.1 of GGQR.

(d) Calculate CO_2 emissions where low Btu gases (e.g., coker flue gas, gases from vapour recovery systems, vents from storage tanks) are destroyed using methods other than flares using the GGQM in section 2.C.3 of GGQR.

(e) Calculation of CO_2 from the use of sorbent.

(1) Where the 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 CO_2 emissions using:

(i) Data from CEMS; or
(ii) Where CEMS is not available, using Equation 20-1 :

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

Equation 20-1

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_{CO2} = Molecular weight of carbon dioxide.
MW_S = Molecular weight of sorbent.

(f) Notwithstanding ON.23(a) through (c) the person is not required to calculate emissions from the combustion of process gas that is transferred from a facility where the amount of process gas that is transferred is included in (c)(14), (d)(8) or (i)14 of ON.152 in a report required to be submitted by the other facility under the Regulation.

(g) Where a quantity of natural gas is distributed by a natural gas distributor to a person's 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 facility; and

(2) Some or all of the natural gas that is recorded by the natural gas billing meter for the facility is used by another facility.

The person is required to include the quantity of natural gas used by the other facility in the value of: "fuel" in ON.23(a) through (c).

(h) The person that is required to quantify and, where applicable, report the GHG emissions from the other facility mentioned in paragraph (g) shall not include the quantity of natural gas received from the facility mentioned in paragraph (g) in the value of: "fuel" in calculations under ON.23(a) through (c).

(i) If a person referenced in paragraph (g) is quantifying emissions using CEMs, the person shall subtract emissions from the use of the fuel provided to them from the emissions calculated using CEMs. The emissions from the subtracted fuel shall be calculated using ON.23(a) through (c).

ON.24 Calculation of CH_4 and N_2O Emissions

The person shall calculate the annual CH_4 and N_2O emissions from fuel combustion and flaring as follows:

(a) Calculate CH4 and N_2O emissions from fuel combustion using the GGQM in section 2.B of GGQR.

(b) Calculate CH4 and N_2O emissions from fuel combustion flares using the GGQM in section 2.C.2 of GGQR.

(c) The person may elect to use engineering estimates to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in the tables in Section 2.B (e.g., Tables 2-7 through 2-11) of the GGQR.

(d) Where a quantity of natural gas is distributed by a natural gas distributor to a person’s 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 facility; and

  (2) Some or all of the natural gas that is recorded by the natural gas billing meter for the facility is used by another facility.

  The person is required to include the quantity of natural gas used by the other facility in the calculating of emission in ON.24(a) through (c).

(e) The person that is required to quantify and, where applicable, report GHG emissions from the other facility mentioned in paragraph (d) shall not include the quantity of natural gas received from the facility mentioned in calculating the emission in ON.24(a) through (c).

(f) If a person referenced in paragraph (d) is quantifying emissions using CEMs, the person shall subtract emissions from the use of the fuel provided to them from the emissions calculated using CEMs. The emissions from the subtracted fuel shall be calculated using ON.24(a) through (c).

ON.25 Sampling, Analysis, and Measurement Requirements

Fuel Sampling Frequency Requirements

(a) Where a calculation in this SQM requires obtaining fuel samples, the person shall obtain those samples in accordance with section 2.D.1 of GGQR.

Fuel Consumption Monitoring Requirements.

(b) Where a calculation in this SQM requires monitoring of fuel consumption the person shall monitor in accordance with section 2.D.2 of GGQR.

(c) 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 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.

(3) For natural gas, using methods and requirements in accordance with the requirements under the Weights and Measurement Act or the Electricity and Gas Inspection Actof Measurement Canada.

(4) 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.

$$HHV = LHV \times CF$$

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 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) A person that is required to use the weighted annual heat content of a fuel shall do so in accordance with section 2.D.3(6) of GGQR.

(g) A person that is required to monitor black liquor heat content shall do so in accordance with section 2.D.3(5) of GGQR.

Fuel Carbon Content Monitoring Requirements.

(h) A 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 or 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

(3) For natural gas, using methods and requirements in accordance with the requirements under the Weights and Measurement Act or the Electricity and Gas Inspection Act of Measurement Canada.

(i) A person that is 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 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) A person that is required to calculate the carbon content of refinery fuel gas and flexigas pursuant to this method shall do so in accordance with section 2.D.4(3) of GGQR.

(k) A person that is required to calculate the weighted annual average carbon content pursuant to this method shall do so in accordance with section 2.D.4(5) of GGQR.

Fuel Analytical Data Capture

(l) If the fuel analytical capture rate is between 80% and 100% for any emission source, use the methods in ON.26 to substitute for the missing value for the period of missing data.

On-site Transportation Consumption of Biofuel

(m) A person that is required to determine the fuel and emission factors pursuant to this method shall do so in accordance with section 2.D.6 of GGQR.

Flares and Other Control Devices

(n) A person that is required to monitor flow rates, carbon content or HHV for flares and other control devices pursuant to this method shall do so in accordance with section 2.D.7 of GGQR.

ON.26 Procedures for Estimating Missing Data

(a) Whenever HHV, carbon content, molecular weight, CO_2 concentration, stack gas flow, moisture percentage, fuel usage and sorbent usage data required for the calculation of emissions is missing, a person shall ensure the data is replaced using the missing data procedures in section 2.E(2) of GGQR.

(b) For all units that monitor and report emissions using a CEMS, use the missing data backfilling procedures in section 2.E(1) of GGQR.

ON.140 Glass Production

ON.141 Activity Definition

For the purposes of this standard quantification method (SQM):

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

(b) Total CO_2 process emissions from all glass melting furnaces (tonnes).

(c) If a CEMS is not used to determine CO_2 emissions from glass melting furnaces, and process CO_2 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.

ON.143 Calculation of CO_2 Emissions

The person shall calculate the annual CO_2 emissions from each glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) Calculate and report the process and combustion CO2 emissions by operating and maintaining CEMS according to ON.23 or using the GGQM in section 2.A.3 of the GGQR if a CEM is required under ON.23.

(b) For each glass melting furnace that is not reported under paragraph (a) of this section, use either the procedure in paragraph (b)(1) of this section or the procedure in paragraph (b)(2) of this section.

(1) Calculate the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to ON.23 or using GGQM in section 2.A.3 of the GGQR.

(2) Calculate the process and combustion CO_2 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 the carbonate-based mineral mass fraction from the supplier of the raw material.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor from Table 140-1 to the method for each carbonate-based raw material charged to the furnace.

(iv) Use Equation 140-1 of this section to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} (M_i \times MF_i \times EF_i \times F_i) \qquad \textbf{Equation 140-1}$$

Where:

E_{CO2} = Process emissions of CO_2 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 CO_2 per tonne carbonate-based mineral from Table 140-1.
F_i = Fraction of calcination achieved for carbonate-based mineral i, 1.0 for completed calcination(weight fraction).

(v) Calculate and report the total process CO_2 emissions from glass melting furnaces at the facility using Equation 140-2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i} \qquad \textbf{Equation 140-2}$$

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (tonnes).
E_{CO2i} = 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 of carbonate-based raw material 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 4), 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. 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.

(d) 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.

(e) The person shall measure the quantity of glass productionusing equiptment that is:

(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:

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

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 “Reference method for source testing quantification of carbon dioxide releases by continuous emission monitoring systems from thermal power generation” shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

Table 140-1 - CO_2 Emission Factors for Carbonate-Based Minerals

Carbonate-Based Raw Material – Mineral	**CO_2 Emission Factor[a]**

Limestone – $CaCO_3$	0.43971
Dolomite – $CaMg(CO_3)_2$	0.47732
Sodium carbonate/soda ash – Na_2CO_3	0.41492

[a] Emission factors in units of tonnes of CO_2 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 (SQM):

“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 SQM 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 (SQM):

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

Proposed activity definition in the regulation: *“hydrogen production”* means processes that produce hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. This activity may occur at bitumen upgraders; petroleum refineries; chemical plants; fertilizer plants; stand-alone industrial gas producers and, where needed, for purification or synthesis of substances.

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

ON.132 Greenhouse Gas Reporting Requirements

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

(b) Report the

(1) total annual quantity of CO2 emissions, expressed in tonnes (t);

(2) total annual quantity of CO2 recovered or captured, expressed in tonnes (t) and whether the CO2 is for downstream use, on-site production or for permanent storage

(3) total annual quantity of hydrogen production, expressed in tonnes (t); and

(4) total annual quantity of hydrogen purchased, expressed in tonnes (t).

(c) Indicate if the CO_2 under (a)(2) that is recovered or captured is for downstream use, on-site production or for permanent storage.

(d) Report the total annual quantity of feedstock charged, reported by feedstock type, expressed in:

(1) cubic metres (m3), for gaseous quantities;

(2) litres (l), for liquid quantities;

(3) tonnes (t), for non-biomass solid quantities; and

(4) bone-dry tonnes (t), for biomass-derived solid fuel quantities.

(e) For each feedstock type reported under section XX, report the annual weighted average carbon content expressed in

(1) kilograms (kg) of C/kilograms (kg) of feedstock, for gaseous quantities;

(2) kilograms (kg) of C/kilograms (kg) of feedstock or kilograms (kg) of C/cubic metres (m3) of feedstock, for liquid quantities; and

(3) kilograms (kg) of C/kilograms (kg) of feedstock, for solid quantities.

(f) Any person subject to this SQM who operates a facility with stacks monitored by CEMS may use the annual emissions data from CEMS to report the emissions under paragraphs (a)(1) and (2). This shall not include the emissions information specified for CEMS in ON.20. The person shall indicate where CEMS is being used to calculate emissions.

ON.133 Calculation of Greenhouse Gas Emissions

(a) The person shall calculate CO_2 process emissions using the greenhouse gas quantification methods (GGQM) in section 10.A of GGQR.

ON.134 Sampling, Analysis, and Measurement Requirements

(a) Persons using the feedstock methodology under section 10.A of GGQR shall follow the procedure under section 10.B of GGQR.

(b) Persons shall quantify the hydrogen produced daily using equipment for measuring the production qualitythat is :

(1) calibrated according to the manufacturer’s instructions and

(2) maintained to achieve an accuracy of plus or minus 5%.

(c) The calibration requirements under paragraph (b) 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.

(d) 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 4).

(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

Missing data requirements for this activity shall be estimated in accordance with section 10.C of the GGQR.

ON.150 Iron, Steel and Ferroalloy Production

ON.151 Activity Definition

For the purposes of this standard quantification method (SQM):

Proposed activity definition in the regulation “Iron and steel and ferroalloy production” means:

1) the production of iron or steel using one of the following primary iron and steel production processes, secondary steelmaking processes, iron production processes, coke oven battery production processes, iron ore pellet firing processes, or iron and steel powder processes.

2) the production of ferroalloy using pyrometallurgical techniques.

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

(b) Report the

(1) total annual quantity of biomass consumed, by biomass type, expressed in tonnes (t); and
(2) type of use for biomass (such as flux material, reducing agent).

(c) For an induration furnace, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of green pellets consumption, expressed in tonnes, if using equation 6-1;
(3) annual weighted average carbon content of green pellets consumption, expressed in tonnes of C/tonnes of green pellets, if using equation 6-1;
(4) total annual quantity of additive material consumption, by material type, expressed in tonnes, if using equation 6-2;
(5) annual weighted average carbon content of additive material consumption, expressed in tonnes of C/tonnes of additive material, if using equation 6-2;
(6) total annual quantity of iron ore concentrate fed to the furnace, expressed in tonnes, if using equation 6-2;
(7) annual weighted average carbon content of iron ore concentrate fed to the furnace, expressed in tonnes of C/tonnes of iron ore concentrate;
(8) total annual quantity of fired pellet production, expressed in tonnes (t);

(9) annual weighted average carbon content of fired pellet production, expressed in tonnes of C/tonnes of fired pellets;
(10) annual quantity of air pollution control residue collected, expressed in tonnes (t);
(11) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue; and
(12) method used to determine the quantities under paragraph (1) above.

(d) For a basic oxygen furnace, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of molten iron charged to the furnace, expressed in tonnes (t);
(3) annual weighted average carbon content of molten iron charged to the furnace, expressed in tonnes of C/tonnes of molten iron;
(4) total annual quantity of ferrous scrap charged to the furnace, expressed in tonnes (t);
(5) annual weighted average carbon content of ferrous scrap charged to the furnace, expressed in tonnes of C/tonnes of ferrous scrap;
(6) total annual quantity of carbonaceous material consumption, by material type, expressed in tonnes (t);
(7) annual weighted average carbon content of non-biomass carbonaceous material consumption, by material type, expressed in tonnes of C/tonnes of carbonaceous material;
(8) total annual quantity of non-biomass flux material charged to the furnace, by material type, expressed in tonnes (t);
(9) annual weighted average carbon content of non-biomass flux material charged to the furnace, expressed in tonnes of C/tonnes of flux;
(10) total annual quantity of molten raw steel production, expressed in tonnes (t);
(11) annual weighted average carbon content of molten raw steel production, expressed in tonnes of C/tonnes of molten raw steel;
(12) total annual quantity of slag production, expressed in tonnes (t);
(13) annual weighted average carbon content of slag production, expressed in tonnes of C/tonnes of slag;
(14) total annual quantity of furnace gas transferred off-site, expressed in tonnes of furnace gas (t) and tonnes of CO2 (t);
(15) annual weighted average carbon content of furnace gas transferred off-site, expressed in tonnes of C/tonnes of furnace gas transferred;
(16) total annual quantity of air pollution control residue collected, expressed in tonnes (t); and
(17) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue.

(e) For coke oven battery, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of coking coal charged to battery, expressed in tonnes (t);
(3) annual weighted average carbon content of non-biomass coking coal charged to battery, expressed in tonnes of C/tonnes of coking coal;
(4) total annual quantity of non-biomass carbonaceous material consumption, other than coking coal charged to battery, by material type, expressed in tonnes (t);
(5) annual weighted average carbon content of non-biomass carbonaceous material consumption, other than coking coal charged to battery, by material type, expressed in tonnes of C/tonnes of carbonaceous material;
(6) total annual quantity of coke produced, expressed in tonnes (t);
(7) annual weighted average carbon content of coke produced, expressed in tonnes of C/tonnes of coke;
(8) total annual quantity of coke oven gas transferred off-site, expressed in tonnes of coke oven gas (t) and tonnes of CO_2;
(9) annual weighted average carbon content of coke oven gas transferred off-site, expressed in tonnes of C/tonnes of coke oven gas;
(10) total annual quantity of by-product from coke oven battery, expressed in tonnes (t);
(11) annual weighted average carbon content of non-biomass by-product from coke oven battery, expressed in tonnes of C/tonnes of by-product;
(12) total annual quantity of air pollution control residue collected, expressed in tonnes (t); and
(13) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue.

(f) For sinter production, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of non-biomass carbonaceous material consumption, by material type, expressed in tonnes (t);
(3) annual weighted average carbon content of non-biomass carbonaceous material consumption, by material type, expressed in tonnes of C/tonnes of carbonaceous material;
(4) total annual quantity of sinter feed material, expressed in tonnes (t);
(5) annual weighted average carbon content of sinter feed material, expressed in tonnes of C/tonnes of sinter feed;
(6) total annual quantity of sinter production, expressed in tonnes (t);
(7) annual weighted average carbon content of sinter production, expressed in tonnes of C/tonnes of sinter production;
(8) total annual quantity air pollution control residue collected, expressed in tonnes (t); and
(9) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue.

(g) For an electric arc furnace, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of direct reduced iron charged to furnace, expressed in tonnes (t);
(3) annual weighted average carbon content of direct reduced iron charged to furnace, expressed in tonnes of C/tonnes of direct reduced iron;
(4) total annual quantity of ferrous scrap charged to furnace, expressed in tonnes (t);
(5) annual weighted average carbon content of ferrous scrap charged to furnace, expressed in tonnes of C/tonnes of ferrous scrap;
(6) total annual quantity of carbonaceous material consumption, by material type, expressed in tonnes (t);
(7) annual weighted average carbon content of non-biomass carbonaceous material consumption, by material type, expressed in tonnes of C/tonnes of carbonaceous material;
(8) total annual quantity of carbon electrode consumption, expressed in tonnes (t);
(9) annual weighted average carbon content of non-biomass carbon electrode consumption, expressed in tonnes of C/tonnes of carbon electrode;
(10) total annual quantity of flux material charged to the furnace, by material type, expressed in tonnes (t);
(11) annual weighted average carbon content of non-biomass flux material charged to the furnace, expressed in tonnes of C/tonnes of flux;
(12) total annual quantity of molten raw steel production or ferroalloys, expressed in tonnes (t);
(13) annual weighted average carbon content of molten raw steel production, expressed in tonnes of C/tonnes of molten raw steel;
(14) total annual quantity of slag production, expressed in tonnes (t);
(15) annual weighted average carbon content of slag production, expressed in tonnes of C/tonnes of slag;
(16) total annual quantity air pollution control residue collected, expressed in tonnes (t);
(17) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue; and
(18) Annual emissions of CH4 emissions from the production of ferroalloys in tonnes (t).

(h) For an argon-oxygen decarburization vessel, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of molten steel charged to the vessel, expressed in tonnes (t);
(3) annual weighted average carbon content of molten steel charged to the vessel, expressed in tonnes of C/tonnes of molten raw steel;

(4) annual weighted average carbon content of molten steel before decarburization, expressed in tonnes of C/tonnes of molten steel;
(5) annual weighted average carbon content of molten steel after decarburization, expressed in tonnes of C/tonnes of molten steel;
(6) total annual quantity of air pollution control residue collected, expressed in tonnes (t); and
(7) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue.

(i) For a direct reduction furnace, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of iron ore or iron ore pellets consumption, expressed in tonnes (t);
(3) annual weighted average carbon content of iron ore or iron ore pellets consumption, expressed in tonnes of C/tonnes of iron ore or iron ore pellets;
(4) total annual quantity of consumed raw material, other than carbonaceous material and ore, by material type, expressed in tonnes (t);
(5) annual weighted average carbon content of raw material, other than carbonaceous material and ore, by material type, expressed in tonnes of C/tonnes of raw material;
(6) total annual quantity of carbonaceous material consumption, by material type, expressed in tonnes (t);
(7) annual weighted average carbon content of non-biomass carbonaceous material consumption, by material type, expressed in tonnes of C/tonnes of carbonaceous material;
(8) total annual quantity of iron production, expressed in tonnes (t);
(9) annual weighted average carbon content of iron production, expressed in tonnes of C/tonnes of iron;
(10) total annual quantity of non-metallic material production, expressed in tonnes (t);
(11) annual weighted average carbon content of non-metallic material production, expressed in tonnes of C/tonnes of non-metallic material;
(12) total annual quantity of air pollution control residue collected, expressed in tonnes (t); and
(13) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue.

(j) For a blast furnace, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of iron ore or iron ore pellets consumption, expressed in tonnes (t);

(3) annual weighted average carbon content of iron ore or iron ore pellets consumption, expressed in tonnes of C/tonnes of iron ore or iron ore pellets;
(4) total annual quantity of consumed raw material, other than carbonaceous material and ore, by material type, expressed in tonnes (t);
(5) annual average carbon content of consumed raw material, other than carbonaceous material and ore, by material type, expressed in tonnes of C/tonnes of raw material;
(6) total annual quantity of carbonaceous material consumption, by material type, expressed in tonnes (t);
(7) annual weighted average carbon content of non-biomass carbonaceous material consumption, by material type, expressed in tonnes of C/tonnes of carbonaceous material;
(8) total annual quantity of flux material charged to the furnace, by material type, expressed in tonnes (t);
(9) annual weighted average carbon content of non-biomass flux material charged to the furnace, expressed in tonnes of C/tonnes of flux;
(10) total annual quantity of iron production, expressed in tonnes (t);
(11) annual weighted average carbon content of iron production, expressed in tonnes of C/tonnes of iron;
(12) total annual quantity of non-metallic material production, expressed in tonnes (t);
(13) annual weighted average carbon content of non-metallic material production, expressed in tonnes of C/tonnes of non-metallic material;
(14) total annual quantity of blast furnace gas transferred off-site, expressed in tonnes of blast furnace gas (t) and tonnes of CO_2;
(15) annual weighted average carbon content of blast furnace gas transferred off-site, expressed in tonnes of C/tonnes of blast furnace gas;
(16) total annual quantity of air pollution control residue collected, expressed in tonnes (t); and
(17) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue.

(k) For the ladle furnace, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of molten steel fed to the furnace, expressed in tonnes (t);
(3) annual weighted average carbon content of molten steel fed to the furnace, expressed in tonnes of C/tonnes of molten steel;
(4) total annual quantity of additive material consumed by the furnace, by material type, expressed in tonnes (t);

(5) annual weighted average carbon content of additive material consumed by the furnace, by material type, expressed in tonnes of C/tonnes of additive material;
(6) total annual carbon electrodes consumed by the furnace, expressed in tonnes (t);
(7) annual weighted average carbon content of carbon electrodes consumed by the furnace, expressed in tonnes of C/tonnes of carbon electrodes;
(8) total annual quantity of molten steel production, expressed in tonnes (t);
(9) annual weighted average carbon content of molten steel production, expressed in tonnes of C/tonnes of molten steel;
(10) total annual quantity of slag production, expressed in tonnes (t);
(11) annual weighted average carbon content of slag production, or a default value of 0, expressed in tonnes of C/tonnes of slag;
(12) total annual quantity of air pollution control residue collected, expressed in tonnes (t);
(13) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue;
(14) total annual quantity of other residue produced, expressed in tonnes (t); and
(15) annual weighted average carbon content of other residue produced or a default value of 0, expressed in tonnes of C/tonnes of residue.

(l) For the atomization of molten cast iron, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of molten cast iron fed into the process, expressed in tonnes (t);
(3) annual weighted average carbon content of molten cast iron fed into the process, expressed in tonnes of C/tonnes of molten cast iron;
(4) total annual quantity of other material used in the process, by material type, expressed in tonnes (t);
(5) annual weighted average carbon content of other material used in the process, by material type, expressed in tonnes of C/tonnes of other material;
(6) total annual quantity of atomized cast iron production, expressed in tonnes (t);
(7) annual weighted average carbon content of atomized cast iron production, expressed in tonnes of C/tonnes of atomized cast iron;
(8) total annual quantity of by-products, by by-product type, expressed in tonnes (t); and
(9) annual weighted average carbon content of by-products, reported by by-product type, expressed in tonnes of C/tonnes of by-product.

(m) For the decarburization of iron powder, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of iron powder fed into the process, expressed in tonnes (t);
(3) annual weighted average carbon content of iron powder fed into the process, expressed in tonnes of C/tonnes of iron powder;
(4) total annual quantity of decarburized iron powder production, expressed in tonnes (t);
(5) annual weighted average carbon content of decarburized iron powder production, expressed in tonnes of C/tonnes of decarburized iron powder production;
(6) total annual quantity of by-product, by by-product type, expressed in tonnes (t); and
(7) (g) annual weighted average carbon content of by-product, by by-product type, expressed in tonnes of C/tonnes of by-product.

(n) For steel grading, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) (b) total annual quantity of molten steel fed into the process, expressed in tonnes (t);
(3) annual weighted average carbon content of molten steel fed into the process, expressed in tonnes of C/tonnes of molten steel;
(4) total annual quantity of additive used in the process, expressed in tonnes (t);
(5) annual weighted average carbon content of additive used in the process, by additive type, expressed in tonnes of C/tonnes of additive;
(6) total annual quantity of carbon electrode consumption, expressed in tonnes (t);
(7) annual weighted average carbon content of carbon electrode consumption, expressed in tonnes of C/tonnes of carbon electrode consumption;
(8) total annual quantity of molten steel production, expressed in tonnes (t);
(9) annual weighted average carbon content of molten steel production, expressed in tonnes of C/tonnes of molten steel production;
(10) total annual quantity of slag production, expressed in tonnes (t);
(11) annual weighted average carbon content of slag production, expressed in tonnes of C/tonnes of slag production;
(12) total annual quantity of air pollution control residue collected, expressed in tonnes (t);
(13) annual weighted average carbon content of air pollution control residue collected, expressed in tonnes of C/tonnes of residue;
(14) total annual quantity of other residue production, expressed in tonnes (t); and
(15) annual weighted average carbon content of other residue production, expressed in tonnes of C/tonnes of other residue.

(o) For steel powder annealing, report the

(1) total annual quantity of CO_2 emissions, expressed in tonnes (t);
(2) total annual quantity of steel powder fed into the process, expressed in tonnes (t);
(3) annual weighted average carbon content of steel powder fed into the process, expressed in tonnes of C/tonnes of steel powder;
(4) total annual quantity of steel powder production, expressed in tonnes (t);
(5) annual weighted average carbon content of steel powder production, expressed in tonnes of C/tonnes of steel powder;
(6) total annual quantity of by-product, by by-product type, expressed in tonnes (t); and
(7) annual weighted average carbon content of by-product, by by-product type, expressed in tonnes of C/tonnes of by-product.

(p) Any person subject to this SQM who operates a facility with stacks monitored by CEMS shall use the GGQM in section 6.A of GGQR for iron and steel production to report

(1) CO_2 emissions information under sections (c) to (n) of this section separately from CO_2 emissions information specified for CEMS in Section ON.23; and
(2) production information specified under paragraphs (c)(8), (c)(10), (c)(12), f(3) ***(was d(4) under GHGRP, changed to d(6))***, (f)(6), (g)(12), (g)(15), (h)(2), (i)(8), (i)(10), (j)(10), (j)(12), (k)(8), (k)(10), (l)(6), (m)(4), (n)(8), (n)(10) and (o)(4).

(q) N_2O, and CH4 process emissions from waste water emissions in tonnes using method ON.203(g).

ON.153 Calculation of CO_2 Emissions

(a) Determine process CO_2 emissions as specified in one of the following:.

(1) Continuous emissions monitoring systems (CEMS) using the GGQM in section 6.A.10 of GGQR.

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

(b) Calculate CO_2 process emissions for each process 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 mass balances in paragraphs (b)(1) through (b)(8).

(1) Taconite indurating furnace CO_2 emissions using the GGQM in section 6.A.1 of GGQR.

(2) Basic oxygen process furnace CO_2 emissions using the GGQM in Section 6.A.2 of GGQR.

(3) Coke oven battery CO_2 emissions using the GGQM in Section 6.A.3 of GGQR.

(4) Sinter process CO_2 emissions using using the GGQM in section 6.A.4 of GGQR.

(5) Electric arc furnace (EAF) CO_2 emissions using the GGQM in section 6.A.5 of GGQR.

(6) Electric arc furnace CH_4 emissions from the production of any ferroalloy using equation 150-1:

$$E_{CH4-FeAlloy} = \sum_{j=1}^{m} \sum_{i=1}^{n} M_{i,j} \times EF_{i,j}$$

Equation 150-1

Where:

$E_{CH4-\text{ FeAlloy}}$ = Annual process CH4 emissions from EAF (tonnes).
Mi = Annual mass of alloy product i produced in the EAF (tonnes).
EF_i = CH4 emission factor for alloy product i from Table 150-1 (tonne CH4/ tonne of alloy product i).
i = ferroalloy product
n = number of ferroalloy products produced at the facility
j = EAF number
m = number of EAFs at the facility

Table 150-1- Electric Arc Furnace (EAF) CH4 Emission Factors

Alloy product produced in EAF	**CH_4 emission factor (tonne CH_4 per metric ton product) EAF Operation**		
	Batch-charging	**Sprinkle-charging[a]**	**Sprinkle-charging and >750 °C[b]**
Silicon metal	0.0015	0.0012	0.0007
Ferrosilicon 90%	0.0014	0.0011	0.0006
Ferrosilicon 75%	0.0013	0.0010	0.0005
Ferrosilicon 65%	0.0010		

[a] Sprinkle-charging is charging intermittently every minute.
[b] Temperature measured in off-gas channel downstream of the furnace hood

(7) Argon-oxygen decarburization vessel CO_2 emissions using the GGQM in section 6.A.6 of GGQR.

(8) Direct reduction furnace CO_2 emissions using using the GGQM in section 6.A.7 of GGQR.

(9) Blast furnace CO2 emissions using the GGQM in section 6.A.8 of GGQR.

(10) Ladle furnace CO_2 emissions using the GGQM in section 6.A.9 of GGQR.

(11) Molten cast iron CO_2 emissions using using the GGQM in section 6.B.1 of GGQR.

(12) Decarburization of iron powder CO_2 emissions using the GGQM in section 6.B.2 of GGQR.

(13) Steel grading CO_2 emissions using the GGQM in section 6.B.3 of GGQR.

(14) Steel powder annealing CO_2 emissions using the GGQM in section 6.B.3 of GGQR.

ON.154 Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in ON.153 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.

(a) The average carbon content of each material used shall be determined in accordance with section 6.C.1 and 6.C.2 of GGQR.

(b) 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.

(c) The person shall measure the quantity of production and material usage used in the calculation as follows.

(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

Missing data requirements for this activity shall be estimated in accordance with section 6.D of the GGQR.

ON.170 Lime Production

ON.171 Activity Definition

For the purposes of this standard quantification method (SQM):

“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) The person shall set out the following information, calculated for the calendar year using SQM ON.170 – ON.175, in an emission report prepared for a calendar year in respect of lime production at a facility.

(b) Total annual quantity of CO_2 emissions from lime production, expressed in tonnes.

(c) Total monthly quantity of lime, by lime type, expressed in tonnes (t);

(d) Monthly plant-specific emission factor, by lime type, expressed in tonnes of CO_2/tonnes of lime;

(e) Monthly calcium oxide (CaO) content of lime, by lime type, expressed in tonnes of CaO/tonnes of lime;

(f) Monthly magnesium oxide (MgO) content of lime, by lime type, expressed in tonnes of MgO/tonnes of lime;

(g) Total quarterly quantity of calcined by-products/wastes, by by-product/waste type, expressed in tonnes (t);

(h) Quarterly plant-specific emission factor of calcined by-products/wastes, by calcined by-product/waste type, expressed in tonnes of CO_2/tonnes of by-product/waste;

(i) Quarterly weighted average calcium oxide (CaO) content of calcined by-products/wastes, by calcined by-product/waste type, expressed in tonnes of CaO/tonnes of by-product/waste; and

(j) Quarterly weighted average magnesium oxide (MgO) content of calcined by-products/wastes, by calcined by-product/waste type, expressed in tonnes of MgO/ tonnes of by-product/waste.

(k) Any person subject to this SQM who operates a facility with stacks monitored by CEMS may use the annual emissions data from CEMS to report the emissions and production quantities under paragraphs (a), (c), and (g).

ON.173 Calculation of Greenhouse Gas Emissions from Kilns

(a) Calculate CO_2 emissions using using the greenhouse gas quantification methods (GGQM) in section 3.A of Canada's Greenhouse Gas Quantification Requirements (GGQR).

ON.174 Sampling, Analysis, and Measurement Requirements

(a) Sampling, analysis and measurement requirements for this activity shall be done in accordance with section 3B of the Greenhouse Gas Quantification. The chemical composition (CaO and MgO contents) of each type of lime and each type of calcined byproduct/waste may also be determine using

(1) Any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 4).

(2) 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) 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.175 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with section 3C of the GGQR.

ON.290 Magnesium Production

ON. 291 Activity Definition

For the purpose of this standard quantification method (SQM):

“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.

“Person” means a person who engages in magnesium production

“Magnesium production” has the same meaning as in Schedule 2 of the Regulation.

ON.292 Greenhouse Gas Reporting Requirements

(a) The person shall set out the following information, calculated for the calendar year using SQM ON.290- ON.295, in an emission report prepared for a calendar year in respect of magnesium production.

(b) The total annual emissions of each greenhouse gas listed in Schedule 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.

(c) Where applicable, an explanation of any change greater than 30 per cent in the facility’s cover gas usage rate from the previous calendar year.

(d) Where applicable, a description of any new melt protection technologies adopted to account for reduced or increased greenhouse gas emissions in the previous reporting period.

(e) 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:

$$E_x = \left(I_{B,x} - I_{E,x} + A_x - D_x\right) \times 0.001$$

Equation 290-1

Where:

E_x = Total GHG emissions from the consumption of cover or carrier gases expressed in tonnes

$I_{B,x}$ = 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:

$$E_x = \sum_{p=1}^{n} Q_p \times 0.001$$

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:

$$Q_p = M_B - M_E$$

Equation 290-3

Where:

Qp = 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) Notwithstandng (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 person 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 person 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 person 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 person 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 person 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 using equipmentthat is :

(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.

$$R_x = \left(\frac{C_x}{Mg} \right) \times 0.001$$

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.

This method is deleted since it will no longer be available in Environment and Climate Change Canada’s Single Window System.

ON.310 Nitric Acid Production

ON.311 Activity Definition

For the purposes of this standard quantification method (SQM):

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

Proposed activity definition in the regulation: “nitric acid production” means the production of weak nitric acid that is 30 to 70 per cent in strength using the catalytic oxidation of ammonia.

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

ON.312 Greenhouse Gas Reporting Requirements

(a) The person shall set out the following information, calculated for the calendar year using SQM ON.310 – ON.315, in an emission report prepared for a calendar year in respect of nitric acid production at a facility:

(b) Report the

(1) total annual quantity of N_2O emissions, expressed in tonnes (t); and

(2) total annual quantity of nitric acid produced, expressed in tonnes (t).

(c) Any person who operates a facility where there is abatement downtime shall report the

(1) annual weighted average N_2O emission factor, expressed in kilograms (kg) of N_2O/tonnes (t) of nitric acid (nitric acid as 100% acid basis);

(2) annual weighted average abatement factor of N_2O abatement technology per acid train, expressed as a fraction of annual nitric acid production per train in which abatement technology is operating; and

(3) destruction efficiency of N_2O abatement technology used on nitric acid train, expressed as per cent of N_2O removed from air stream, by type of abatement technology and shall includedocumentation demonstrating how process knowledge was used to estimate destruction efficiency, if not specified by the manufacturer or estimated using Equation 9-3 of Canada’s Greenhouse Gas Quantification Requirements (GGQR).

(d) Any person who operates a facility where the NOx abatement is integrated within the operating process and cannot be bypassed shall report the annual weighted average N_2O emission factor, expressed in kilograms (kg) of N_2O/tonnes (t) of nitric acid, 100% acid base.

(e) Any person who operates a facility with stacks monitored by CEMS may use the annual emissions data from CEMS to report the emissions under paragraph (a)(1). The person shall indicate where CEMS is being used to calculate emissions.

(f) Total CO_2 emissions from the reducing agents used in the non-selective catalytic reduction units (tonnes CO_2), calculated using ON.313(b).

(g) Total CH_4 emissions from unreacted methane in reducing agents used in the non-selective catalytic reduction unit (tonnes CH_4), calculate using ON.313(b).

ON.313 Calculation of GHG emissions

(a) Calculate nitric acid production emissions using the greenhouse gas quantification methods (GGQM) in section 9.A of GGQR.

(b) 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 310-1 and 310-2 of this section.

$$E_{ra\_CO2} = Q_a \times (1 - M_s) \times C_a \times 3.664$$

Equation 310-1

$$E_{ra\_CH4} = Q_a \times (M_s) \times C_{CH4}$$

Equation 310-2

Where:

E_{ra_CO2} = Annual CO_2 emissions from other reducing agents or material used (tonnes);

E_{ra_CH4} = 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_{CH4} = 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 NOx CEMS shall use the procedures in section 9.B(2) of GGQR.

(c) The person shall measure the N_2O 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 a non-dispersive infrared (NDIR) analyzer within a stack monitoring system where the method is equivalent to EPA method 320, or 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.

(d) 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).

(e) 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.

(f) The person shall determine the monthly nitric acid production quantity and the monthly nitric acid production quantity during which N_2O 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%.

(g) The person shall determine the annual nitric acid production quantity and the annual nitric acid production quantity during which N_2O 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

Missing data requirements for this activity shall be estimated in accordance with section 9.C of the GGQR.

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 (SQM):

"Automated mass-flow measurement" means the use of mass-flow meters attached to electrical power distribution equipment to directly measure the amount of SF_6 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 Schedule 2 of 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 SF_6 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 SF_6 or PFC added to the equipment.

ON.232 Greenhouse Gas Reporting Requirements

(a) A person shall set out the following information, calculated for the calendar year using SQM ON.230 – ON.235, in an emission report prepared for a calendar year in respect of electricity transmission and distribution at a facility:

(b) The SF_6 and PFC emissions from electricity transmission and distribution and distribution calculated in accordance with ON.233(a) and (b).

ON.233 Calculation of SF_6 and PFC Emissions

(a) A person shall use one of the following calculation methodologies to calculate SF_6 emissions

(1) Mass Balance Methodology.

(i) Calculate the change in inventory of SF_6 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 SF_6 in storage expressed in kilograms

$S_{Inv\text{-}Begin}$ = Quantity of SF_6 in storage at the beginning of the reporting period expressed in kilograms;

$S_{Inv\text{-}End}$ = Quantity of SF_6 in storage at the end of the reporting period expressed in kilograms

(ii) Calculate the amount of all SF_6 acquired during the year that is contained either in storage containers or in electrical power distribution equipment using Equation 230-2.

$$S_{PA} = S_{Cyl} + S_{Equip} + S_{\mathrm{Re}cyc-ret}$$ **Equation 230-2**

Where:

S_{PA} = Sum of all SF_6 acquired during the year that is contained either in storage containers or in electrical power distribution equipment expressed in kilograms;

S_{Cyl} = Quantity of SF_6 in storage containers obtained from producers or distributors expressed in kilograms;

S_{Equip} = Quantity of SF_6 stored or contained inside equipment provided by electrical power distribution equipment manufacturers expressed in kilograms;

$S_{Recyc\text{-}ret}$ = Quantity of SF_6 returned to site after off-site recycling expressed in kilograms.

(iii) Calculate the sum of all SF_6 transferred out of the facility during the year either in storage containers or in electrical power distribution equipment using Equation 230-3.

$$S_{SD} = S_{Sales} + S_{\mathrm{Re}turns} + S_{Destruct} + S_{\mathrm{Re}cyc-off}$$ **Equation 230-3**

Where:

S_{SD} = Sum of all SF_6 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 SF_6 sold or transferred to other facilities including SF_6 that is left in electrical power distribution equipment that is sold expressed in kilograms;

$S_{Returns}$ = Quantity of SF_6 returned to suppliers expressed in kilograms;

$S_{Destruct}$ = Quantity of SF_6 sent to destruction facilities expressed in kilograms;

$S_{Recyc\text{-}off}$ = Quantity of SF_6 sent off-site for recycling expressed in kilograms.

(iv) Calculate the net increase in total nameplate capacity of electrical power distribution equipment that uses SF_6 using Equation 230-4.

$$\Delta S_{Cap} = S_{Cap-new} - S_{Cap-retire}$$ **Equation 230-4**

Where:

ΔS_{Cap} = Net increase in total nameplate capacity of electrical power distribution equipment that uses SF_6 expressed in kilograms

$S_{Cap\text{-}new}$ = Total nameplate capacity of new electrical power distribution equipment at proper full charge expressed in kilograms;

$S_{Cap\text{-}retire}$ = 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.

$$S = \left(\Delta S_{Inv} + S_{PA} - S_{SD} - \Delta S_{Cap}\right) / 1{,}000$$ **Equation 230-5**

Where:

S = Total annual SF_6 emissions expressed in tonnes;

ΔS_{Inv} = Change in inventory of SF_6 in storage expressed in kilograms calculated in accordance with Equation 230-1;

S_{PA} = Sum of all SF_6 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 SF_6 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 SF_6 expressed in kilograms calculated in accordance with Equation 230-4

1,000 = Factor to convert kilograms to tonnes.

(2) Direct Measurement Methodology.

(i) SF_6 emissions from the operations phase shall be calculated by directly measuring the mass of SF_6 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.

$$S_O = \sum_{i}^{N} s_i$$

Equation 230-6

Where:

S_O = Annual SF_6 emissions during the operation phase expressed in kilograms;

N = Number of SF_6 additions in a given year;

s_i = SF_6 added to electrical power distribution equipment during addition *i*, expressed in kilograms

(ii) SF_6 emissions from the decommissioning phase shall be calculated by directly measuring the amount of SF_6 collected from any decommissioned electrical power distribution equipment calculated in accordance with Equation 230-7.

$$S_D = \sum_{i}^{N} (NC_i - S_i)$$

Equation 230-7

Where:

S_D = Annual SF_6 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 = SF_6 collected from decommissioned electrical power distribution equipment *i*, expressed in kilograms.

(iii) Total annual SF_6 emissions are calculated according to Equation 230-8.

$$S = \frac{S_O + S_D}{1{,}000}$$

Equation 230-8

Where:

S = Annual SF_6 emissions expressed in tonnes;
S_O = Annual SF_6 emissions during operation phase expressed in kilograms;
S_D = Annual SF_6 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 SF_6 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 annually 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:

$$R = \frac{QS_{Act}}{QS_{Required}}$$ **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 SF_6 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 (SQM):

“Blowdown vent stack emissions” mean natural gas and/or CO_2 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 CO_2 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 CO_2 from escaping to the atmosphere.

“Centrifugal compressor dry seals emissions” mean natural gas or CO_2 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 CO_2. 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/scraper 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 equiment 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 SQM ON.350 – ON.355, in an emission report prepared for a calendar year in respect of Operation of equipment related to natural gas:

(1) CO_2 and CH_4 (and N_2O, 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 CO_2, CH_4 and N_2O 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 CO_2, CH_4 and N_2O 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 CO_2, CH_4 and N_2O 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 CO_2, CH_4 and N_2O 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 CO_2, CH_4 and N_2O 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 CO_2, CH_4 and N_2O 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:

$$E_s = Q_j \quad \textbf{Equation 350-1}$$

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:

$$E_s = EF_j \times t_j$$ **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 (Sm^3/h/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:

$$EF_j = m \times SP_j$$ **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) <u>Natural gas pneumatic pump venting.</u> 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.

$$E_s = EF_j \times t_j$$ **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 (Sm^3/h/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 EFj parameter for pumps may be calculated using Equation 350-3a[1]

$$EF_j = \left(g \times SP_j\right) + \left(n \times DP_j\right) = \left(p \times SPM_j\right)$$ **Equation 350-3a**

Where:

EF_j = bleed rate, the volume of natural gas bled per hour for pneumatic pump (or equivalent pump),j (Sm^3NG/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 350-3b

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[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.

$$EF_j = Q_j \times R_j \qquad \textbf{Equation 350-3b}$$

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 (Sm^3NG/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.

$$E_s = EF_j \times t_j \qquad \textbf{Equation 350-4}$$

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 (Sm^3/h/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:

$$E_s = EF_j \times t_j$$ **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) (Sm^3/h/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.

$$EF_j = m \times SP_j$$ **Equation 350-5a**

Where:

m = The supply pressure coefficient in Table 350-6

SP_j = The supply pressure (kPa) of the pneumatic device.

(A) 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 (Sm^3/min/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:

$$E = V_j \left[\frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a) P_s Z_a} \right]$$ **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 (ºC).

T_a = Temperature at actual conditions in the equipment system (ºC).

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 ≥ 1.416 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

$$M = \sqrt{\frac{2\left[\left(\frac{P_a}{P_e}\right)^{\frac{K-1}{K}} - 1\right]}{K-1}}, (for\ M \leq 1)$$

Equation 350-9

Where:

M = 1, (for all other cases)

Q = natural gas venting volumetric flow rate (Sm^3/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-m^3/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:

Qs = natural gas venting volumetric flow rate (Sm3/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 CH_4 and CO_2 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 CO_2, CH_4, and N_2O 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.

$$E_{s,CH4}(noncombusted) = Q_s \times (1 - \eta) \times Y_{CH4}$$ **Equation 350-12**

$$E_{s,CO2}\ (noncombusted) = Q_s \times Y_{CO2}$$ **Equation 350-13**

$$E_{s,CO2}(combusted) = \sum_i \eta \times Q_s \times Y_i \times n_i$$ **Equation 350-14**

$$E_{s,CO2}(total) = E_{s,CO2}(combusted) + E_{s,CO2}(noncombusted)$$ **Equation 350-15**

Where:

$E_{s,CH4}$ (noncombusted) = Contribution of annual noncombusted volumetric CH_4 emissions from flare stack (Sm^3).

$E_{s,CO2}$ (noncombusted) = Contribution of annual volumetric CO_2 emissions from CO_2 in the inlet gas passing through the flare noncombusted (Sm^3).

$E_{s,CO2}$ (combusted) = Contribution of annual volumetric CO2 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_{CH4} = Mole fraction of CH_4 in gas to the flare.

Y_{CO2} = 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.

$$E_{N20} = Q_s \times HHV \times EF \times 0.001$$ **Equation 350-16**

Where:

E_{N2O} = 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 CO_2, and CH_4, and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing vent lines, but excluding dry seal 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.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF) \quad \textbf{Equation 350-17}$$

Where:

$E_{s,i}$ = Annual GHG *i* (either CH_4 or CO_2) volumetric emissions from all compressor venting modes (Sm^3).

$Q_{s,m}$ = Measured volumetric gas emissions during operating mode *m* described in paragraph (8)(v) of this section (Sm^3/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

$$E_{s,i,c} = E_{s,i} + E_{m,nf} \qquad \textbf{Equation 350-17a}$$

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) Not withstanding 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 CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 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 CH_4 and CO_2 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.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i(1 - CF)$$ **Equation 350-18**

Where:

$E_{s,i}$ = Annual volumetric emissions of GHG *i* (either CH_4 or CO_2) from all compressor venting modes (Sm^3/y).

$Q_{s,m}$ = Measured volumetric gas emissions during operating mode *m* described in paragraph (9)(v) (Sm^3/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.

$$E_{s,i,c} = E_{s,i} + E_{m,nf}$$ **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) Not withstanding 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 CH_4 and CO_2 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 Qs,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 CO_2e or greater shall use this calculation method. If the total emissions from the site are less than 10,000 tonnes CO_2e, 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 CH_4 plus CO_2 by weight. Emissions sources in streams with gas containing less than 10 percent CH_4 plus CO_2 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 [Sm^3/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.

$$E_i = EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001 \qquad \textbf{Equation 350-19}$$

$$E_{s,j} = EF_s \times Y_i \times t \qquad \textbf{Equation 350-20}$$

Where:

$E_{s,i}$ or $E_{s,j}$= Annual total mass emissions of GHG_i (CH_4 or CO_2) 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 (Sm^3/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 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; or use the experimentally determined gas composition for CO_2 and CH_4. For mass emissions in Equation 350-20, use mass fractions of CH_4 and CO_2 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/m^3 for CO_2 and 0.678 kg/m^3 for CH_4 at standard conditions of 15 ^oC 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 CH_4 plus CO_2 by weight. Emissions sources in streams with gas containing less than 10 percent CH_4 plus CO_2 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 [m^3/h/component]) or Equation 350-22 (for mass emission factors [kg/h/component]) of this section, as appropriate.

$$E_i = N \times EF_s \times Y_i \times t \times p_{s,i} \times 0.001 \qquad \textbf{Equation 350-21}$$

$$E_i = N \times EF_s \times X_i \times t \times 0.001 \qquad \textbf{Equation 350-22}$$

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 (Sm^3/component/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 x 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 x 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).

$p_{s,i}$ = 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 ºC 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 ºC and 1 atmosphere) using Equation 350-23 of this section.

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$ **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 º).

T_a = Temperature at actual emission conditions (ºC).

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.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$ **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 CH_4 and CO_2 emissions from natural gas emissions using Equation 350-25 of this section

$$E_{s,i} = E_s \times Y_i$$ **Equation 350-25**

Where:

$E_{s,i}$ = GHG$_i$ (either CH_4 or CO_2) 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 by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 350-26 of this section.

$$E_i = E_{s,i} \times \rho_{s,i} \times 0.001$$ **Equation 350-26**

Where:

E_i = GHG$_i$ (either CH_4, CO_2, or N_20) mass emissions (tonnes).

$E_{s,i}$ = GHG$_i$ (either CH_4, CO_2 or N_2O) volumetric emissions at standard conditions (Sm^3).

$\rho_{s,i}$ = 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 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 CH_4, CO_2 and N_2O (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 winstrument 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 CH_4 and CO_2 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 CH_4 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 CH_4 and CO_2 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 (Sm^3/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 SM^3). *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 (Sm^3/hour/component) Prasino Final Pneumatic Field Sampling Report* Direct conversion of EF's in EPA Subpart W Table* W-4 (scf to Sm^3)
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.

[1] Valves 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 (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-5 (scf to
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

[1] The "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 (Sm^3/hour/component) Direct conversion of EF's in EPA Subpart W Table W-6 (scf to Sm^3)
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 (Sm^3/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 (Sm^3/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 (Sm^3/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/m^3.

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 ^{o}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
P	Variable - density
η	Variable – efficiency (fractional)

ON.190 Other Emissions

ON.191 Activity Definition

For the purposes of this standard quantification method (SQM):

“Other Emissions” means emission not reported under other SQM, and excludes CO_2 from biomass decomposition.

“Person” means a person that engages in one or more activities listed in Column 1 of Schedule 2 of the Regulation and that is required by the regulation to report GHG emissions resulting from those activities

ON.192 Greenhouse Gas Reporting Requirements

(a) Where a person has GHG emissions resulting from engaging in one or more activities listed in Column 1 of Schedule 2 of the Regulation that are not quantified using the standard quantification method for that activity, the person shall set out the following information, calculated for the calendar year using this SQM ON.190 – ON.194, in an emission report prepared for a calendar year in respect of a facility:

(b) total annual quantity of CO2 emissions for each category of emission, expressed in tonnes (t);

(c) total annual CH4 emissions for each category of emission, expressed in tonnes (t);

(d) total annual N2O emissions for each catogory of emission, expressed in tonnes (t);

(e) total annual CO2 emissions from biomass combustion, expressed in tonnes (t)

(f) total annual CH4 and N2O emissions from biomass combustion, expressed in tonnes (t);

(g) Total annual emissions of SF6, and each HFC and PFC, expressed in tonnes (t);

(h) the source category of the emissions

(1) stationary fuel combustion,

(2) industrial process,

(3) industrial product use,

(4) venting,

(5) flaring,

(6) leakage,

(7) on-site transportation,

(8) waste, and

(9) waste water.

(i) The method used to calculate the emissions (e.g., monitoring or direct measurements, mass balance, emission factors, or engineering estimates)

ON.193 Calculation of GHG Emissions

The person shall quantify emissions from each source category listed in ON.192 (7) using one of the following:

(a) A method that is consistent with the 2008 Intergovernmental Panel on Climate Change (IPCC) Guideline;

(b) A method that is consistent with a calculation method(s) in another SQM in this Guideline.

ON.194 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance with the following:

(a) Direct measurements or estimates derived from direct measurements of the parameters required for the calculations;

(b) Quantities of material, energy, production or any other parameters from invoices, shipping records, purchase records, financial records, or data used for accounting purposes;

(c) Measurement and other data from suppliers;

(d) Engineering estimates of parameters required for the calculations;

(e) Literature values of parameters.

ON.300 Petrochemical Production

ON.301 Activity Definition

For the purposes of this standard quantification method (SQM):

“Petrochemical production” has the same meaning as in schedule 2 of the Regulation.

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

ON.302 Greenhouse Gas Reporting Requirements

(a) A person shall set out the following information, calculated for the calendar year using SQM ON.300 – ON.305, in an emission report prepared for a calendar year in respect of petrochemical production at a facility.

(b) CO_2, N_2O, and CH_4 emissions from flares or other combustion devices in tonnes using methods ON.303(a)(1), ON.303(a)(2) or ON.303(c).

(c) CO_2, N_2O, and CH_4 process emissions from vents in tonnes using method ON.303(a)(3).

(d) CO_2, N_2O, and CH_4 process emissions from equipment leaks in tonnes using method ON.303(a)(4).

(e) CO_2 process emissions in tonnes using method ON.303(b).

(f) CO_2, N_2O, and CH_4 process emissions from ethylene production facilities in tonnes using method ON.303(c).

(g) 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.

(h) N_2O, and CH_4 process emissions from waste water emissions in tonnes using method ON.203(g).

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 CO_2, CH_4 and N_2O emissions using the methods specified in ON.200.

  (2) For combustion devices other than flares, calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of fuels and process off-gas as specified in paragraphs (a)(2)(i) through (a)(2)(iii):

(i) Calculate CO_2 emissions from fuels and process off-gas in accordance with the methods in specified in ON.23.

(ii) Calculate CH_4 and N_2O emissions from combustion of fuels using the applicable methods in ON.24.

(iii) Calculate CH_4 and N_2O emissions from process off-gas using the applicable methods in ON.24 and the default emission factors of 2.8×10^{-3} kg/GJ for CH_4 and 5.7×10^{-4} kg/GJ for N_2O.

(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 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.

(4) Calculate the emissions from equipment leaks using the method specified in ON.203(i)(1).

(b) <u>Calculation Methodology 2:</u> Calculate the emissions of CO_2 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 CO_2 and the methods specified in ON.24 for CH_4 and N_2O.

(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 re-evaluate 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 CO_2 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.

$$C_g = \sum_{n=1}^{12} [\sum_{i=1}^{j\ or\ k} [\ (F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC}\ ]]$$

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” (Rm^3) 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 $(F_{gf})_{i,n}$ (Rm^3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

$(P_{gp})_{i,n}$ = Volume of gaseous product i produced in month “n” (Rm^3) 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 CO_2 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.

$$C_l = \sum_{n=1}^{12}[\sum_{i=1}^{j\,or\,k}[(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n}]] \qquad \textbf{Equation 300-2}$$

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” (m^3 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 m^3 of feedstock when feedstock usage is measured in m^3 , 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” (m^3). 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 m^3 of product when liquid product is measured in m^3, 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.

$$C_s = \sum_{n=1}^{12} \left\{ \sum_{i=1}^{j\,or\,k} \left[\left(F_{sf}\right)_{i,n} * \left(CC_{sf}\right)_{i,n} - \left(P_{sp}\right)_{i,n} * \left(CC_{sp}\right)_{i,n} \right] \right\}$$ **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 CO_2 emissions.

$$CO_2 = 0.001 * 3.664 * \left(C_g + C_l + C_s\right)$$ **Equation 300-4**

Where:

CO_2 = Annual CO_2 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 CO_2, CH_4, and N_2O emissions as specified in paragraphs (c)(1) and (c)(2):

(1) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology for flares specified in ON.203(e).

(2) For all other combustion units, calculate the CO_2 emissions from combustion of fuel that contains ethylene process off-gas using either Calculation Methodologies 3 or 4 in ON.23, respectively. Calculate CH_4 and N_2O emissions using the applicable method in ON.24 and the emission factors of 2.8×10^{-3} kg/GJ for CH_4 and 5.7×10^{-4} kg/GJ for N_2O. 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) Production Parameter. The person shall measure the production parameter quantities using the same plant instruments used for accounting purposes. Equipment used to measure the production parameter quantities 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 with 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 4 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:

$$R = Q_{S\ Act}/Q_{S\ Required} \qquad \textbf{Equation 300-5}$$

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.304

(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;

(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 “Reference method for source testing quantification of carbon dioxide releases by continuous emission monitoring systems from thermal power generation” shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

This method is deleted since it will no longer be available in Environment and Climate Change Canada’s Single Window System.

ON.200 Petroleum Refining

ON.201 Activity Definition

For the purposes of this standard quantification method (SQM):

“Petroleum refining” has the same meaning as in Schedule 2 of the Regulation.

Proposed activity definition in the regulation “Petroleum refining” means processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through the distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives. This includes catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (i.e. compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulphur recovery plants; and non-merchant hydrogen plants that are owned or under the direct control of the refinery owner and operator. This does not include facilities that distill only pipeline transmix.

“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) A person shall set out the following information, calculated for the calendar year using SQM ON.200 – ON.205, in an emission report prepared for a calendar year in respect of petroleum refining at a facility with the exception of information related to hydrogen production emissions, which the person shall report using ON.130 of this Guideline:

(b) Report the total annual quantity of CO_2, CH4, and N_2O emissions from catalyst regeneration, expressed in tonnes (t).

(c) Report the total annual quantity of CO_2, CH4, and N_2O emissions from process vents, expressed in tonnes (t).

(d) Report the total annual quantity of CO_2, CH4, and N_2O emissions from asphalt production, expressed in tonnes (t).

(e) Report the total annual quantity of CO_2 emissions from sulphur recovery units, expressed in tonnes (t) and shall provide documentation of the methodology if they are using a source-specific molar fraction of CO_2 in sour gas in ON.203(d).

(f) Report the total annual quantity of CH4 emissions from above-ground storage tanks, expressed in tonnes (t).

(g) Report the total annual quantity of CH4 and N_2O emissions from wastewater treatment plants, expressed in tonnes (t).

(h) Report the total annual quantity of CH4 emissions from oil-water separators, expressed in tonnes (t).

(i) Report the total annual quantity of CH4 emissions from equipment leaks at refineries, expressed in tonnes (t).

(j) Report the total annual quantity of CO_2, CH4, and N_2O emissions from coking calcining units, expressed in tonnes (t).

(k) Report the total annual quantity of CO_2, CH4, and N_2O emissions from uncontrolled blowdown systems, expressed in tonnes (t).

(l) Report the total annual quantity of CH4 emissions from loading operations, expressed in tonnes (t).

(m)Report the total annual quantity of CH4 emissions from delayed coking units, expressed in tonnes (t).

(n) Report, for each of crude oil, propane, butane and ethanol brought into the facility for input into the refining process, report the

(1) total annual quantities

(i) of crude oil and ethanol expressed in kilolitres (kl), and
(ii) of propane and butane expressed in cubic metres(m3);

(2) annual higher heating value of each, expressed in megajoules (MJ) per unit; and

(3) annual average carbon content of each, expressed in kilograms (kg)of carbon per unit.

(o) For each feedstock used under sections (b) to (m) report the total annual

(1) gaseous quantities, expressed in cubic metres (m3);

(2) solid quantities, expressed in tonnes (t);

(3) liquid quantities, expressed in kilolitres (kl); and

(4) biomass-derived solid quantities, expressed in bone-dry tonnes(t).

(p) Any person who operates a facility with stacks monitored by CEMS may use the annual emissions data from CEMS to report the emissions and production information under section (b) through section (m). This shall not include the emissions information specified for CEMS in ON.20 of this notice. The person shall indicate where emissions calculations use CEMS.

(q) The following Complexity weighted barrel (CWB) parameters:

(1) The Direct Only CAN-CWB$_{\text{(without cogeneration)}}$, 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, offsites and non-energy utilities, non-crude sensible heat, sales and exports of steam and electricity identified in the CAN-CWB Methodology.

(3) The Total CO_2e 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 if present inside the refinery and if the ratio of electricity output (in GJ) to the total energy input (in GJ) of the cogeneration unit is greater than 5%.

(4) The Direct-only CO_2 emissions in the calendar year from the petroleum refinery including Hydrogen Generation units emissions but excluding cogeneration emissions expressed in tonnes if present inside the refinery and if the ratio of electricity output (in GJ) to the total energy input (in GJ) of the cogeneration unit is greater than 5%.

(5) The Total Input Barrels described in the CAN-CWB Methodology expressed in barrels per calendar day.

(6) The Non-Crude Input Barrels described in the CAN-CWB Methodology (expressed in barrels per calendar day).

(7) The Imported Steam to the refinery, including steam originating from a cogeneration unit located inside the refinery expressed in million BTU per calendar day.

(8) The Imported Electricity to the refinery, including electricity originating from a cogeneration unit located inside the refinery expressed in megawatt hour per calendar day.

(9) 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.

(10) 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 GHG emissions using the methods in paragraphs (a) through (m) of this section. If a CEMS is used to measure CO_2 emissions from process vents, asphalt production, sulphur recovery, or other control devices then the person may calculate the CO_2 emissions from these processes using a continuous emissions monitoring system (CEMS) as specified in ON.23.

When the flue gas from two or more processes or fuel combustion sources are discharged through a common stack or duct before exiting to the atmosphere and if CEMS as specified in ON.23 are used to continuously monitor the CO_2 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) Calculate CO_2, CH4, and N_2O emissions from catalyst regeneration using the greenhouse gas quantification methods (GGQM) in section 11.A of Canada's Greenhouse Gas Quantification Requirements (GGQR).
(b) Calculate CO_2, CH4, and N_2O emissions from process vents using the GGQM in section 11.B of GGQR.
(c) Asphalt Production. Calculate CO_2 and CH_4 process emissions from asphalt production activities using the GGQM in section 11.C of GGQR.

(d) Calculate CO_2 and CH4 process emissions from sulphur recovery using the GGQM in section 11.D of GGQR.

(e) Calculate CO_2 and CH4 process emissions from flares and other control devices using the GGQM in section 11.E of GGQR.

(f) Calculate CH_4 emissions from storage tanks using the GGQM in section 11.F of GGQR.
(g) Calculate CH4 process emissions from industrial wastewater processing using the GGQM in section 11.G of GGQR.
(h) Calculate CH4 emissions from oil-water separators using the GGQM in section 11.H of GGQR.

(i) Calculate CH4 emissions from equipment leaks using the GGQM in section 11.I of GGQR.

(j) Calculate GHG emissions from petroleum coke calcining using the GGQM in section 11.J of GGQR.

(k) For uncontrolled blowdown systems, the person shall use the methods for process vents in paragraph (b) of this section.

(l) Calculate CH4 emissions from loading operations using the GGQM in section 11.L of GGQR.

(m) Calculate CH4 emissions from delayed coking units using the GGQM in section 11.M of GGQR.

(n) CAN-CWB(without cogeneration). Calculate CAN-CWB (without cogeneration) using the following steps.

(1) Calculate the CWBref using the CAN-CWB Methodology for all Standard Refining Process Units, including the hydrogen generated via Hydrogen Generation units expressed in CWBref per calendar day. The value of the "CWB factor" for hydrogen generation for all process types is 5.70. 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 and if the ratio of electricity output (in GJ) to the total energy input (in GJ) of the cogeneration unit is greater than 5%.

(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 if the cogeneration unit emissions were excluded from paragraph (n)(2) of this subsection. 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 if the cogeneration unit emissions were excluded from paragraph 2.

(4) Calculate the Direct Only CAN-CWB $_{\text{(without Cogeneration)}}$ 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, or calculated by using the value from paragraph (n)(1) times the value from paragraph (n)(2), divided by the sum of paragraph (n)(2) and (n)(3).

(5) Calculate the annual Direct Only CAN-CWB $_{\text{(without cogeneration)}}$ by multiplying (4) 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 parameters required in section 11.N.1 of GGQR.

(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 parameters required in section 11.N.2 of GGQR.

(c) Asphalt Production. The person shall measure the mass of asphalt blown, as required in section 11.N.3 of GGQR.

(d) Sulphur Recovery. The person shall measure the volumetric flow rate of acid gas to the SRU in accordance with section 11.N.4 of GGQR.

(e) Flares and Other Control Devices. The person shall measure the parameters in accordance with section 11.N.5 of GGQR (or ON.26.n).

(f) Storage Tanks. The person shall determine the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank in accordance with section 11.N.6 of GGQR.

(g) Wastewater Treatment. The person shall measure the parameters in accordance with section 11.N.7 of GGQR.

(h) Oil-Water Separators. The person shall measure the daily volume of waste water treated by the oil-water separators as required under section 11.N.8 of GGQR.

(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 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 4).

(5) The most appropriate method published by a consensus-based standards organization or, 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

Missing data requirements for this activity shall be estimated in accordance with section 11.OE of the GGQR.

ON.340 Phosphoric acid Production

ON.341 Activity Definition

For the purposes of this standard quantification method (SQM):

“Phosphoric acid production” has the same meaning as in Schedule 2 of 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 SQM ON.340 – ON.345, in an emission report prepared for a calendar year in respect of phosphoric acid production at a facility:

(a) CO_2 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.210 Pulp and Paper Production

ON.211 Activity Definition

For the purposes of this standard quantification method (SQM):

"Pulp and paper production" has the same meaning as in the Regulation.

Proposed activity definition in the regulation "Pulp and paper production" means the production of pulp, paper and paper products by separating cellulose fibres from other materials in fibre sources, including but not limited to the conversion of paper into paperboard products and the operation of coating and laminating processes.

"Person" means a person that engages in pulp and paper production.

ON.212 Greenhouse Gas Reporting Requirements

(a) The person shall set out the following information, calculated for the calendar year using SQM ON.210 – ON.215, in an emission report prepared for a calendar year in respect of pulp and paper production at a facility.

(b) Any person subject to this SQM shall report the following:

(1) total annual quantity of CO_2 emissions from the addition of carbonates in the chemical recovery of chemical pulp mills, expressed in tonnes (t);

(2) total annual CH_4 and N_2O emissions from on-site wastewater treatment plants, expressed in tonnes (t);

(3) total annual quantity of pulp, expressed in tonnes (t) of air dried pulp;

(4) total annual quantity of input carbonate material, by carbonate type, expressed in tonnes (t);

(5) annual weighted average carbon content of input carbonate material, by carbonate type, expressed in tonne of carbon per tonne of carbonate material, if using equation 12-2 in section 12 of Canada's Greenhouse Gas Quantification Requirements (GGQR);

(6) total annual quantity of carbon-containing process output material, by material type, expressed in tonnes (t), if using equation 12-2 in section 12 of GGQR;

(7) annual weighted average carbon content of carbon-containing process output material, by material type, expressed in tonne of carbon per tonne of material, if using equation 12-2 in section 12 of GGQR; and

(8) annual weighted average of fraction of calcination achieved, by type of carbonate used, if using equation 12-3 in section 12 of GGQR and if not using the default value, the method used must be provided.

(c) Any person subject to this SQM who operates a facility with stacks monitored by CEMS may use the annual emissions data from CEMS to report the emissions information under paragraphs (a)(1) and (a)(2). This shall not include the emissions information specified for CEMS in ON.20. The person shall indicate where CEMS is being used to calculate emissions.

(d) N_2O, and CH_4 process emissions from waste water emissions in tonnes using method ON.203(g).

ON.213 Calculation of GHG Emissions

(a) Calculate CO_2, CH_4 and N_2O 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 ON.20 or ON.40.

(b) For make-up chemical use, calculate CO_2 emissions by using the greenhouse gas quantification methods (GGQM) in section 12.A.2 of GGQR.

(c) For wastewater emissions, calculate CO_2 emissions by using the GGQM in section 12.A.3 of GGQR.

ON.214 Sampling, Analysis, and Measurement Requirements

(a) The person shall follow the sampling, analysis and measurement requirement in accordance with section 12.B of GGQR.

ON.215 Procedures for Estimating Missing Data

Missing data requirements for this activity shall be estimated in accordance with section 12.C of the GGQR.

ON.220 Soda Ash Production

ON.221 Activity Definition

For the purposes of this standard quantification method (SQM):

“Soda ash production” has the same meaning as in Schedule 2 of the Regulation.

“Person” means a person that engages in soda ash production.

ON.222 Greenhouse Gas Reporting Requirements

(a) A person shall set out the following information, calculated for the calendar year using SQM ON.220 – ON.225, in an emission report prepared for a calendar year in respect of soda ash production at a facility.

(b) CO_2 process emissions from soda ash manufacturing line (tonnes).

(c) 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.270 Wastewater Processing

ON.271 Activity Definition

For the purposes of this standard quantification method (SQM):

“Wastewater processing” means industry waste water processing from the facilities engaged in the industrial activity of industrial processing of potato or oilseed for human or animal consumption, producing ethanol by distillation for use in the production of alcoholic beverages, or processing corn through wet milling.

ON.272 Greenhouse Gas Reporting Requirements

(a) A person shall set out the following information, calculated for the calendar year using this SQM ON.273 – ON.274, in an emission report prepared for a calendar year in respect of a facility.

(b) Any person subject to this method shall report N_2O, and CH_4 process emissions from waste water emissions in tonnes using method ON.203(g).

ON.273 Calculation of GHG Emissions

(a) Quantify emissions using method ON.203(g) in this Guideline.

ON.274 Sampling, Analysis, and Measurement Requirements

Sampling, analysis and measurement requirements for this activity shall be done in accordance ON.204(g) in this Guideline.

ON.275 Procedures for Estimating Missing Data

The missing data procedures shall be done in accordance with ON.205.