National Greenhouse and Energy Reporting (Measurement) Determination 2008[1]

National Greenhouse and Energy Reporting Act 2007

I, PENELOPE YING YEN WONG, Minister for Climate Change and Water, make this Determination under subsection 10 (3) of the *National Greenhouse and Energy Reporting Act 2007*.

Dated 25 June 2008

PENNY WONG
Minister for Climate Change and Water

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Chapter 1 General

Part 1.1 Preliminary

1.1 Name of Determination

This Determination is the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*.

1.2 Commencement

This Determination commences on 1 July 2008.

Division 1.1.1 Overview

1.3 Overview — general

(1) This Determination is made under subsection 10 (3) of the *National Greenhouse and Energy Reporting Act 2007*. It provides for the measurement of the following arising from the operation of facilities:

(a) greenhouse gas emissions;

(b) the production of energy;

(c) the consumption of energy.

Note For the meaning of ***facility***, see section 9 of the Act.

(2) This Determination deals with scope 1 and scope 2 emissions.

Note Scope 1 and scope 2 emissions are defined in subregulation 2.23 (2) of the Regulations.

(3) There are 4 categories of scope 1 emissions dealt with in this Determination.

Note This Determination does not deal with emissions released directly from land management.

(4) The 4 categories of scope 1 emissions are:

(a) UNFCCC Category 1.A — Fuel combustion activities, which deals with emissions released from fuel combustion (Chapter 2); and

(b) UNFCCC Category 1.B — Fugitive emissions from fuels, which deals with emissions released from the extraction, production, flaring of fuels, processing and distribution of fossil fuels (Chapter 3); and

(c) UNFCCC Category 2 — Industrial processes emissions, which deals with emissions released from the calcining of carbonates and the use of fuels as feedstocks or as carbon reductants, and the emission of synthetic gases in particular cases (Chapter 4); and

(d) UNFCCC Category 6 — Waste emissions, which deals with emissions which are mainly released from the decomposition of organic material in landfill or wastewater handling facilities (Chapter 5).

Note The sources are categorised according to the classification system of the IPCC (see section 1.10).

(5) Each of the categories has various subcategories.

1.4 Overview — methods for measurement

(1) This Determination provides methods and criteria for the measurement of the matters mentioned in subsection 1.3 (1).

(2) Generally:

(a) method 1 (known as the default method) is derived from the National Greenhouse Accounts methods and is based on national average estimates; and

(b) method 2 is a facility specific method using industry practices for sampling and Australian or equivalent standards for analysis; and

(c) method 3 is the same as method 2 but is based on Australian or equivalent standards for both sampling and analysis; and

(d) method 4 provides for facility specific measurement of emissions by continuous or periodic emissions monitoring.

Note Method 4, that applies as indicated by provisions of this Determination, is as set out in Part 1.3.

1.5 Overview — energy

Chapter 6 deals with the estimation of the production and consumption of energy.

1.6 Overview — scope 2 emissions

Chapter 7 deals with scope 2 emissions.

1.7 Overview — assessment of uncertainty

Chapter 8 deals with the assessment of uncertainty.

Division 1.1.2 Definitions and interpretation

1.8 Definitions

In this Determination:

2006 IPCC Guidelines means the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* published by the IPCC.

accredited laboratory means a laboratory accredited by the National Association of Testing Authorities or an equivalent member of the International Laboratory Accreditation Cooperation in accordance with AS ISO/IEC 17025:2005, and for the production of calibration gases, accredited to ISO Guide 34:2000.

Act means the *National Greenhouse and Energy Reporting Act 2007*.

ANZSIC industry classification and code means an industry classification and code for that classification published in the Australian and New Zealand Standard Industrial Classification (ANZSIC), 2006.

APHA followed by a number means a method of that number issued by the American Public Health Association and, if a date is included, of that date.

API Compendium means the document known as the *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*, 2004, published by the American Petroleum Institute.

applicable State or Territory legislation, for an underground mine, means a law of a State or Territory in which the mine is located that relates to coal mining health and safety, as in force on 1 July 2008.

Note Applicable State or Territory legislation includes:

- *Coal Mine Health and Safety Act 2002* (NSW) and the *Coal Mine Health and Safety Regulation 2006* (NSW)
- *Coal Mining Safety and Health Act 1999* (Qld) and the *Coal Mining Safety and Health Regulation 2001* (Qld).

appropriate standard, for a matter or circumstance, means an Australian standard or an equivalent international standard that is appropriate for the matter or circumstance.

appropriate unit of measurement, in relation to a fuel type, means:

(a) for solid fuels — tonnes; and

(b) for gaseous fuels — metres cubed or gigajoules, except for liquefied natural gas which is kilolitres; and

(c) for liquid fuels other than those mentioned in paragraph (d) — kilolitres; and

(d) for liquid fuels of one of the following kinds — tonnes:

    (i) crude oil, including crude oil condensates, other natural gas liquids;

    (ii) petroleum coke;

(iii) refinery gas and liquids;
(iv) refinery coke;
(v) bitumen:
(vi) waxes;
(vii) carbon black if used as petrochemical feedstock;
(viii) ethylene if used as a petrochemical feedstock;
(ix) petrochemical feedstock mentioned in item 57 of Schedule 1 to the Regulations.

AS or ***Australian standard*** followed by a number (for example, AS 4323.1—1995) means a standard of that number issued by Standards Australia Limited and, if a date is included, of that date.

ASTM followed by a number (for example, ASTM D6347/D6347M-99) means a standard of that number issued by ASTM International and, if a date is included, of that date.

biogenic carbon fuel means energy that is:

(a) derived from plant and animal material, such as wood from forests, residues from agriculture and forestry processes and industrial, human or animal wastes; and
(b) not embedded in the earth for example, like coal oil or natural gas.

blended fuel means fuel that is a blend of fossil and biogenic carbon fuels.

calibrated to a measurement requirement, for measuring equipment, means calibrated to a specific characteristic, for example a unit of weight, with the characteristic being traceable to:

(a) a measurement requirement provided for under the *National Measurement Act 1960* or any instrument under that Act for that equipment; or
(b) a measurement requirement under an equivalent standard for that characteristic.

CEM or ***continuous emissions monitoring*** means continuous monitoring of emissions in accordance with Part 1.3.

CEN/TS followed by a number (for example, CEN/TS 15403) means a technical specification (TS) of that number issued by the European Committee for Standardization and, if a date is included, of that date.

CO_2-e means carbon dioxide equivalence.

COD or ***chemical oxygen demand*** means the total material available for chemical oxidation (both biodegradable and non-biodegradable) measured in tonnes.

compressed natural gas has the meaning given by the Regulations.

core sample means a cylindrical sample of the whole or part of a strata layer, or series of strata layers, obtained from drilling using a coring barrel with a diameter of between 50 mm and 2 000 mm.

crude oil condensates has the meaning given by the Regulations.

documentary standard means a published standard that sets out specifications and procedures designed to ensure that a material or other thing is fit for purpose and consistently performs in the way it was intended by the manufacturer of the material or thing.

dry wood has the meaning given by the Regulations.

efficiency method has the meaning given by subsection 2.70 (2).

EN followed by a number (for example, EN 15403) means a standard of that number issued by the European Committee for Standardization and, if a date is included, of that date.

energy content factor, for a fuel, means gigajoules of energy per unit of the fuel measured as gross calorific value.

extraction area, in relation to an open cut mine, is the area of the mine from which coal is extracted.

feedstock has the meaning given by the Regulations.

flaring means the combustion of fuel for a purpose other than producing energy.

Example

The combustion of methane for the purpose of complying with health, safety and environmental requirements.

fuel means a substance mentioned in column 2 of an item in Schedule 1 to the Regulations.

fuel oil has the meaning given by the Regulations.

fugitive emissions means the release of emissions that occur during the extraction, processing and delivery of fossil fuels.

gas bearing strata is a layer of rock that contains quantities of gas.

gas stream means the flow of gas subject to monitoring under Part 1.3.

gassy mine means an underground mine that has at least 0.1% methane in the mine's return ventilation.

Global Warming Potential means, in relation to a greenhouse gas mentioned in column 2 of an item in the table in regulation 2.02 of the Regulations, the value mentioned in column 4 for that item.

GPA followed by a number means a standard of that number issued by the Gas Processors Association and, if a date is included, of that date.

green and air dried wood has the meaning given by the Regulations.

higher-method has the meaning given by subsection 1.18 (5).

hydrofluorocarbons has the meaning given by section 4.99.

ideal gas law means the state of a hypothetical ideal gas in which the amount of gas is determined by its pressure, volume and temperature.

IEC followed by a number (for example, IEC 17025:2005) means a standard of that number issued by the International Electrotechnical Commission and, if a date is included, of that date.

incidental, for an emission, has the meaning given by subregulation 4.27 (5) of the Regulations.

integrated steelworks has the meaning given in subsection 4.64 (2).

invoice includes delivery record.

IPCC is short for Intergovernmental Panel on Climate Change established by the World Meteorological Organization and the United Nations Environment Programme.

ISO followed by a number (for example, ISO 10396:2007) means a standard of that number issued by the International Organization of Standardization and, if a date is included, of that date.

lower method has the meaning given by subsection 1.18 (6).

method, for a source, means a method specified in this Determination for estimating emissions released from the operation of a facility in relation to the source.

municipal materials has the meaning given by the Regulations.

N/A means not available.

National Greenhouse Accounts means the set of national greenhouse gas inventories, including the National Inventory Report 2005, submitted by the Australian government to meet its reporting commitments under the United Nations Framework Convention on Climate Change and the 1997 Kyoto Protocol to that Convention.

natural gas distribution is distribution of natural gas through low-pressure pipelines with pressure of 1 050 kilopascals or less.

natural gas liquids has the meaning given by the Regulations.

natural gas transmission is transmission of natural gas through high-pressure pipelines with pressure greater than 1 050 kilopascals.

non-gassy mine means an underground mine that has less than 0.1% methane in the mine's return ventilation.

open cut mine means a mine in which the overburden is removed from coal seams to allow extraction by mining that is not underground mining.

PEM or ***periodic emissions monitoring*** means periodic monitoring of emissions in accordance with Part 1.3.

Perfluorocarbon protocol means the *Protocol for Measurement of Tetrafluoromethane* (CF_4) *and Hexafluoroethane* (C_2F_6) *Emissions from Primary Aluminium Production* published by the United States Environmental Protection Agency and the International Aluminium Institute.

petroleum based oils has the meaning given by the Regulations.

petroleum coke has the meaning given by the Regulations.

post-mining activities, in relation to a mine, is the handling, stockpiling, processing and transportation of coal extracted from the mine.

principal activity, in relation to a facility, means the activity that:

(a) results in the production of a product or service that is produced for sale on the market; and

(b) produces the most value for the facility out of any of the activities forming part of the facility.

reductant means a fuel that is used for its chemical properties other than its property as a source of energy.

refinery gases and liquids has the meaning given by the Regulations.

Regulations means the *National Greenhouse and Energy Reporting Regulations 2008*.

run-of-mine coal means coal that is produced by mining operations before screening, crushing or preparation of the coal has occurred.

scope 1 emissions has the meaning given by paragraph 2.23 (2) (a) of the Regulations.

scope 2 emissions has the meaning given by paragraph 2.23 (2) (b) of the Regulations.

Note Regulation 2.23 provides that emissions of greenhouse gases, in relation to a facility, means releases of greenhouse gases as a result of:

(a) activities that constitute the facility (scope 1 emissions); and

(b) activities that generate electricity, heating, cooling or steam that are consumed by the facility but do not form part of the facility (scope 2 emissions).

sludge biogas means the gas derived from the anaerobic fermentation of biomass and solid waste from sewage and animal slurries and combusted to produce heat and electricity.

source means a source of emissions.

standard includes a protocol, technical specification or USEPA method.

standard conditions has the meaning given by subsection 2.32 (7).

sulphite lyes has the meaning given by the Regulations.

synthetic gas generating activities has the meaning given by subsections 4.100 (1) and (2).

underground mine means a coal mine that allows extraction of coal by mining at depth, after entry by shaft, adit or drift, without the removal of overburden.

UNFCCC or ***United Nations Framework Convention on Climate Change*** means the convention of that name done at New York on 9 May 1992.

USEPA followed by a reference to a method (for example, Method 3C) means a standard of that description issued by the United States Environmental Protection Agency.

waxes has the meaning given by the Regulations.

year means a financial year.

Note The following expressions in this Determination are defined in the Act:

- carbon dioxide equivalence
- consumption of energy (see also subregulation 2.23 (4) of the Regulations)
- emission of greenhouse gas (see also subregulation 2.23 (2) of the Regulations)
- energy
- facility
- group
- greenhouse gas
- industry sector
- operational control
- production of energy (see also subregulation 2.23 (3) of the Regulations)
- registered corporation.

1.9 Interpretation

(1) In this Determination, a reference to ***emissions*** is a reference to emissions of greenhouse gases.

(2) In this Determination, a reference to a ***gas type (j)*** is a reference to a greenhouse gas.

(3) In this Determination, a reference to a facility that is ***constituted*** by an activity is a reference to the facility being constituted in whole or in part by the activity.

Note Section 9 of the Act defines a facility as an activity or series of activities.

(4) In this Determination, a reference to a standard, instrument or other writing (other than a Commonwealth Act or Regulations) however described, is a reference to that standard, instrument or other writing as in force on 1 July 2008.

1.10 Description of sources

In this Determination, a description of a source by number followed by a letter, number or a combination of letters and numbers (for example, Source 1.A) is a reference to the source of a category of emissions corresponding to that description in the revised 1996 IPCC *Guidelines for National Greenhouse Gas Inventories* as adopted by the UNFCCC.

Part 1.2 General

1.11 Purpose of Part

This Part provides for general matters as follows:

(a) Division 1.2.1 provides for the measurement of emissions and also deals with standards;

(b) Division 1.2.2 provides for methods for measuring emissions.

Division 1.2.1 Measurement and standards

1.12 Measurement of emissions

The measurement of emissions released from the operation of a facility is to be done by estimating the emissions in accordance with this Determination.

1.13 General principles for measuring emissions

Estimates for this Determination must be prepared in accordance with the following principles:

(a) transparency — emission estimates must be documented and verifiable;

(b) comparability — emission estimates using a particular method and produced by a registered corporation in an industry sector must be comparable with emission estimates produced by similar corporations in that industry sector using the same method and consistent with the emission estimates published by the Department in the National Greenhouse Accounts;

(c) accuracy — having regard to the availability of reasonable resources by a registered corporation and the requirements of this Determination, uncertainties in emission estimates must be minimised and any estimates must neither be over nor under estimates of the true values at a 95% confidence level;

(d) completeness — all identifiable emission sources within the energy, industrial process and waste sectors as identified by the *National Inventory Report* must be accounted for.

1.14 Assessment of uncertainty

The estimate of emissions released from the operation of a facility must include assessment of uncertainty in accordance with Chapter 8.

1.15 Units of measurement

(1) For this Determination, measurements of fuel must be converted as follows:

(a) for solid fuel, to tonnes; and

(b) for liquid fuels, to kilolitres unless otherwise specified; and

(c) for gaseous fuels, to cubic metres, corrected to standard conditions, unless otherwise specified.

(2) For this Determination, emissions of greenhouses gases must be estimated in CO_2-e tonnes.

(3) Measurements of energy content must be converted to gigajoules.

(4) The *National Measurement Act 1960*, and any instrument made under that Act, must be used for conversions required under this section.

1.16 Rounding of amounts

(1) If:

(a) an amount is worked out under this Determination; and

(b) the number is not a whole number;

then:

(c) the number is to be rounded up to the next whole number if the number at the first decimal place equals or exceeds 5; and

(d) rounded down to the next whole number if the number at the first decimal place is less than 5.

(2) Subsection (1) applies to amounts that are measures of emissions or energy.

1.17 Status of standards

If there is an inconsistency between this Determination and a documentary standard, this Determination prevails to the extent of the inconsistency.

Division 1.2.2 Methods

1.18 Method to be used for a source

(1) This section deals with the number of methods that may be used to estimate emissions of a particular greenhouse gas released, in relation to a source, from the operation of a facility.

(2) Subject to subsection (3), one method for the source must be used for 4 reporting years unless another higher method is used.

(3) If:

(a) at a particular time, a method is being used to estimate emissions in relation to the source; and

(b) in the preceding 4 reporting years before that time, only that method has been used to estimate the emissions from the source;

then a lower method may be used to estimate emissions in relation to the source from that time.

(4) In this section, ***reporting year***, in relation to a source from the operation of a facility under the operational control of a registered corporation and entities that are members of the corporation's group, means a year that the registered corporation is required to provide a report under section 19 of the Act in relation to the facility

(5) ***Higher method***, in relation to a method (the ***original method***) being used to estimate emissions in relation to a source, is a method for the source with a higher number than the number of the original method.

(6) ***Lower method,*** in relation to a method (the ***original method***) being used to estimate emissions in relation to a source, is a method for the source with a lower number than the number of the original method.

1.19 Temporary unavailability of method

(1) The procedure provided for in this section applies if, during a year, a method for a source cannot be used because of a mechanical or technical failure of equipment during a period (the ***down time***).

(2) For each day or part of a day during the down time, emissions must be calculated based on the average daily emissions estimated for the year.

(3) Subsection (2) only applies for a maximum of 6 weeks in a year. This period does not include down time taken for the calibration of the equipment.

(4) Use of this procedure for a maximum of 6 weeks in a year is not a change of method for the purposes of section 1.18.

Part 1.3 Method 4 — Direct measurement of emissions

Division 1.3.1 Preliminary

1.20 Overview

(1) This Chapter provides for method 4 for a source.

Note Method 4 as provided for in this Part applies to a source as indicated in the Chapter, Part, Division or Subdivision dealing with the source.

(2) Method 4 requires the direct measurement of emissions released from the source from the operation of a facility during a year by monitoring the gas stream at a site within part of the area (for example, a duct or stack) occupied for the operation of the facility.

(3) Method 4 consists of the following:

(a) method 4 (CEM) as specified in section 1.21 that requires the measurement of emissions using continuous emissions monitoring (***CEM***);

(b) method 4 (PEM) as specified in section 1.27 that requires the measurement of emissions using periodic emissions monitoring (***PEM***).

Division 1.3.2 Operation of method 4 (CEM)

Subdivision 1.3.2.1 Method 4 (CEM)

1.21 Method 4 (CEM) — estimation of emissions

(1) To obtain an estimate of the mass of emissions of a gas type (***j***), being methane, carbon dioxide or nitrous oxide, released at the time of measurement at a monitoring site within the area occupied for the operation of a facility, the following formula must be applied:

$$M_{jct} = \frac{MM_j \times P_{ct} \times FR_{ct} \times C_{jct}}{8.314 T_{ct}}$$

where:

M_{jct} is the mass of emissions in tonnes of gas type (***j***) released per second.

MM_j is the molecular mass of gas type (***j***) measured in tonnes per kilomole which:

(a) for methane is 16.04×10^{-3}; or

(b) for carbon dioxide is 44.01×10^{-3}; or

(c) for nitrous oxide is 44.01×10^{-3}.

P_{ct} is the pressure of the gas stream in kilopascals at the time of measurement.

FR_{ct} is the flow rate of the gas stream in cubic metres per second at the time of measurement.

C_{jct} is the proportion of gas type (***j***) in the volume of the gas stream at the time of measurement.

T_{ct} is the temperature, in degrees kelvin, of the gas at the time of measurement.

(2) The mass of emissions estimated under subsection (1) must be converted into CO_2-e tonnes.

(3) Data on estimates of the mass emissions rates obtained under subsection (1) during an hour must be converted into a representative and unbiased estimate of mass emissions for that hour.

(4) The estimate of emissions of gas type (***j***) during a year is the sum of the estimates for each hour of the year worked out under subsection (3).

(5) The total mass of emissions for a gas from the source for the year calculated under this section must be reconciled against an estimate for that gas from the facility for the same period calculated using method 1 for that source.

Subdivision 1.3.2.2 Method 4 (CEM) — use of equipment

1.22 Overview

The following apply to the use of equipment for CEM:

(a) the requirements in section 1.23 about location of the sampling positions for the CEM equipment;

(b) the requirements in section 1.24 about measurement of volumetric flow rates in the gas stream;

(c) the requirements in section 1.25 about measurement of the concentrations of greenhouse gas in the gas stream;

(d) the requirements in section 1.26 about frequency of measurement.

1.23 Selection of sampling positions for CEM equipment

For paragraph 1.22 (a), the location of sampling positions for the CEM equipment in relation to the gas stream must be selected in accordance with an appropriate standard.

Note Appropriate standards include:

- AS 4323.1—1995 *Stationary source emissions - Selection of sampling positions*.
- AS 4323[1].1—1995 Amdt 1-1995 *Stationary source emissions - Selection of sampling positions*.
- ISO 10396:2007 *Stationary source emissions - Sampling for the automated determination of gas emission concentrations for permanently-installed monitoring systems*.
- ISO 10012:2003 *Measurement management systems - Requirements for measurement processes and measuring equipment*.
- USEPA – *Method 1 – Sample and Velocity Traverses for Stationary Sources* (2000).

1.24 Measurement of flow rates by CEM

For paragraph 1.22 (b), the measurement of the volumetric flow rates by CEM of the gas stream must be undertaken in accordance with an appropriate standard.

Note Appropriate standards include:

- ISO 10780:1994 *Stationary source emissions — Measurement of velocity and volume flowrate of gas streams in ducts*.
- ISO 14164:1999 *Stationary source emissions — Determination of the volume flowrate of gas streams in ducts - Automated method*.
- USEPA Method 2 *Determination of Stack Gas Velocity and Volumetric flowrate (Type S Pitot tube)* (2000).
- USEPA Method 2A *Direct Measurement of Gas Volume Through Pipes and Small Ducts* (2000).

1.25 Measurement of gas concentrations by CEM

For paragraph 1.22 (c), the measurement of the concentrations of gas in the gas stream by CEM must be undertaken in accordance with an appropriate standard.

Note Appropriate standards include:

- USEPA Method 3A *Determination of oxygen and carbon dioxide concentrations in emissions from stationary sources (instrumental analyzer procedure)* (2006).
- USEPA Method 3C *Determination of carbon dioxide, methane, nitrogen, and oxygen from stationary sources* (1996).
- ISO 12039:2001 *Stationary source emissions — Determination of carbon monoxide, carbon dioxide and oxygen — Performance characteristics and calibration of automated measuring system*.

1.26 Frequency of measurement by CEM

(1) For paragraph 1.22 (d), measurements by CEM must be taken frequently enough to produce data that is representative and unbiased.

(2) For subsection (1), if part of the CEM equipment is not operating for a period, readings taken during periods when the equipment was operating may be used to estimate data on a pro rata basis for the period that the equipment was not operating.

(3) Frequency of measurement will also be affected by the nature of the equipment.

Example

If the equipment is designed to measure only one substance, for example, carbon dioxide or methane, measurements might be made every minute. However, if the equipment is designed to measure different substances in alternate time periods, measurements might be made much less frequently, for example, every 15 minutes.

(4) The CEM equipment must operate for more than 90% of the period for which it is used to monitor an emission.

(5) In working out the period during which CEM equipment is being used to monitor for the purposes of subsection (4), exclude downtime taken for the calibration of equipment.

Division 1.3.3 Operation of method 4 (PEM)

Subdivision 1.3.3.1 Method 4 (PEM)

1.27 Method 4 (PEM) — estimation of emissions

(1) To obtain an estimate of the mass emissions rate of methane, carbon dioxide or nitrous oxide released at the time of measurement at a monitoring site within the area occupied for the operation of a facility, the formula in subsection 1.21 (1) must be applied.

(2) The mass of emissions estimated under the formula must be converted into CO_2-e tonnes.

(3) The average mass emissions rate for the gas measured in CO_2-e tonnes per hour for a year must be calculated from the estimates obtained under subsection (1).

(4) The total mass of emissions of the gas for the year is calculated by multiplying the average emissions rate obtained under subsection (3) by the number of hours during the year when the site was operating.

(5) The total mass of emissions of the gas for a year calculated under this section must be reconciled against an estimate for that gas from the site for the same period calculated using method 1 for that source.

1.28 Calculation of emission factors

(1) Data obtained from periodic emissions monitoring of a gas stream may be used to estimate the average emission factor for the gas per unit of fuel consumed or material produced.

(2) In this section, ***data*** means data about:
   (a) gas concentrations; or
   (b) volumetric flow rates; or
   (c) consumption of fuel; or
   (d) material produced.

Subdivision 1.3.3.2 Method 4 (PEM) — use of equipment

1.29 Overview

The following requirements apply to the use of equipment for PEM:
(a) the requirements in section 1.30 about location of the sampling positions for the PEM equipment;
(b) the requirements in section 1.31 about measurement of volumetric flow rates in a gas stream;
(c) the requirements in section 1.32 about measurement of the concentrations of greenhouse gas in the gas stream;
(d) the requirements in section 1.33 about representative data.

1.30 Selection of sampling positions for PEM equipment

For paragraph 1.29 (a), the location of sampling positions for PEM equipment must be selected in accordance with an appropriate standard.

Note Appropriate standards include:

- AS 4323.1—1995 *Stationary source emissions — Selection of sampling positions*.
- AS 4323.1-1995 Amdt 1-1995 *Stationary source emissions — Selection of sampling positions*.
- ISO 10396:2007 *Stationary source emissions — Sampling for the automated determination of gas emission concentrations for permanently-installed monitoring systems*.
- ISO 10012:2003 *Measurement management systems — Requirements for measurement processes and measuring equipment*.
- USEPA Method 1 *Sample and Velocity Traverses for Stationary Sources* (2000).

1.31 Measurement of flow rates by PEM equipment

For paragraph 1.29 (b), the measurement of the volumetric flow rates by PEM of the gas stream must be undertaken in accordance with an appropriate standard.

Note Appropriate standards include:

- ISO 10780:1994 *Stationary source emissions – Measurement of velocity and volume flowrate of gas streams in ducts*.
- ISO 14164:1999 *Stationary source emissions. Determination of the volume flow rate of gas streams in ducts - automated method*.
- USEPA Method 2 *Determination of stack velocity and volumetric flow rate (Type S Pitot tube) (2000)*.
- USEPA Method 2A *Direct measurement of gas volume through pipes and small ducts (2000)*.

1.32 Measurement of gas concentrations by PEM

For paragraph 1.29 (c), the measurement of the concentrations of greenhouse gas in the gas stream by PEM must be undertaken in accordance with an appropriate standard.

Note Appropriate standards include:

- USEPA Method 3A *Determination of oxygen and carbon dioxide concentrations in emissions from stationary sources (instrumental analyser procedure)* (2006).
- USEPA Method 3C *Determination of carbon dioxide, methane, nitrogen, and oxygen from stationary sources* (1996).
- ISO12039:2001 *Stationary source emissions – Determination of carbon monoxide, carbon dioxide and oxygen - Performance characteristics and calibration of an automated measuring method*.

1.33 Representative data for PEM

(1) For paragraph 1.29 (d), sampling by PEM must be undertaken during the year for a sufficient duration to produce representative data that may be reliably extrapolated to provide estimates of emissions across the full range of operating conditions for that year.

(2) Emission estimates using PEM equipment must also be consistent with the principles in section 1.13.

Division 1.3.4 Performance characteristics of equipment

1.34 Performance characteristics of CEM or PEM equipment

(1) The performance characteristics of CEM or PEM equipment must be measured in accordance with this section.

(2) The test procedure specified in an appropriate standard must be used for measuring the performance characteristics of CEM or PEM equipment.

(3) For the calibration of CEM or PEM equipment, the test procedure must be:

(a) undertaken by an accredited laboratory; or

(b) undertaken by a laboratory that meets requirements equivalent to ISO 17025; or

(c) undertaken in accordance with applicable State or Territory legislation.

(4) As a minimum requirement, a cylinder of calibration gas must be certified by an accredited laboratory accredited to ISO Guide 34:2000 as being within 2% of the concentration specified on the cylinder label.

Chapter 2 Fuel combustion (UNFCCC Category 1.A)

Part 2.1 Preliminary

2.1 Outline of Chapter

This Chapter provides for UNFCCC Category 1.A (fuel combustion) and related matters as follows:

(a) Part 2.2 provides for emissions released from the combustion of solid fuels — UNFCCC Category 1.A (solid fuels);

(b) Part 2.3 provides for emissions released from the combustion of gaseous fuels — UNFCCC Category 1.A (gaseous fuels);

(c) Part 2.4 provides for emissions released from the combustion of liquid fuels — UNFCCC Category 1.A (liquid fuels);

(d) Part 2.5 provides for emissions released from fuel use by certain industries — UNFCCC categories 1.A.1.b, 1.A.1.c and 1.A.2.c;

(e) Part 2.6 provides for measurement of fuels in blended fuels;

(f) Part 2.7 provides for the estimation of energy for certain purposes.

Part 2.2 Emissions released from the combustion of solid fuels

Division 2.2.1 Preliminary

2.2 Application

This Part applies to UNFCCC Category 1.A — solid fuels.

2.3 Available methods for estimating emissions of carbon dioxide, methane and nitrous oxide

(1) Subject to section 1.18, for estimating emissions released from the combustion of a solid fuel consumed from the operation of a facility during a year:

(a) one of the following methods must be used for estimating emissions of carbon dioxide:

(i) subject to subsection (3), method 1 under section 2.4;

(ii) method 2 using an oxidation factor under section 2.5 or an estimated oxidation factor under section 2.6;

(iii) method 3 using an oxidation factor or an estimated oxidation factor under of section 2.12;

(iv) method 4 under Part 1.3; and

(b) method 1 under section 2.4 must be used for estimating emissions of methane and nitrous oxide.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

(3) If the principal activity of the facility is electricity generation (ANZSIC industry classification and code 2611), method 1 must not be used.

Note There is no method 2, 3 or 4 for paragraph (1) (b).

Division 2.2.2 Method 1 — emissions of carbon dioxide, methane and nitrous oxide from solid fuels

2.4 Method 1 — solid fuels

For subparagraph 2.3 (1) (a) (i), method 1 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1\,000}$$

where:

E_{ij} is the emissions of gas type (***j***), being carbon dioxide, methane or nitrous oxide, released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type ***(i)*** measured in tonnes and estimated under Division 2.2.5.

EC_i is the energy content factor of the type of fuel measured in gigajoules per tonne according to source as mentioned in Schedule 1.

EF_{ijoxec} is the emission factor for each gas type (***j***) (which includes the effect of an oxidation factor) released from the combustion of fuel type (***i***) measured in kilograms of CO_2-e per gigajoule according to source as mentioned in Schedule 1.

Division 2.2.3 Method 2 — emissions from solid fuels

Subdivision 2.2.3.1 Method 2 — estimating carbon dioxide using default oxidation factor

2.5 Method 2 — estimating carbon dioxide using oxidation factor

(1) For subparagraph 2.3 (1) (a) (ii), method 2 is:

$$E_{ico_2} = \frac{Q_i \times EC_i \times EF_{ico_2oxec}}{1\ 000}$$

where:

E_{ico2} means the emissions of carbon dioxide released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) measured in tonnes and estimated under Division 2.2.5.

EC_i is the energy content factor of fuel type (***i***) measured in gigajoules per tonnes:

(a) estimated by analysis of the fuel in accordance with the standard indicated for that parameter in Schedule 2 or an equivalent standard; or

(b) according to source as mentioned in Schedule 1.

EF_{ico_2oxec} is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms of CO_2-e per gigajoule as worked out under subsection (2).

(2) For EF_{ico_2oxec} in subsection (1), estimate as follows:

$$EF_{ico_2oxec} = \frac{EF_{ico_2ox,kg}}{EC_i} \times 1\ 000$$

where:

$EF_{ico_2ox,kg}$ is the carbon dioxide emission factor for fuel type (*i*) measured in kilograms of CO_2-e per kilogram of fuel as worked out under subsection (3).

EC_i is the energy content factor of fuel type (*i*) as obtained under subsection (1).

(3) For $EF_{ico_2ox,kg}$ in subsection (2), work out as follows:

$$EF_{ico_2ox,kg} = \frac{C_{ar}}{100} \times OF_s \times 3.664$$

where:

C_{ar} is the percentage of carbon in fuel type (*i*), as received for the facility or as fired from the operation of the facility, worked out under subsection (4).

OF_s, or oxidation factor, is:

(a) if the principal activity of the facility is electricity generation — 0.99; or

(b) in any other case — 0.98.

(4) For C_{ar} in subsection (3), work out as follows:

$$C_{ar} = \frac{C_{daf} \times (100 - M_{ar} - A_{ar})}{100}$$

where:

C_{daf} is the amount of carbon in fuel type (*i*) as a percentage of the dry ash-free mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

M_{ar} is the amount of moisture in fuel type (*i*) as a percentage of the as received or as fired mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

A_{ar} is the amount of ash in fuel type (*i*) as a percentage of the as received or as fired mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

Subdivision 2.2.3.2 Method 2 — estimating carbon dioxide using an estimated oxidation factor

2.6 Method 2 — estimating carbon dioxide using an estimated oxidation factor

(1) For subparagraph 2.3 (1) (a) (ii), method 2 is:

$$E_{ico_2} = \frac{Q_i \times EC_i \times EF_{ico_2oxec}}{1\,000}$$

where:

E

E_{ico2} means the emissions of carbon dioxide released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) measured in tonnes and estimated under Division 2.2.5.

EC_i is the energy content factor of fuel type (***i***) measured in gigajoules per tonnes:

(a) estimated by analysis of the fuel in accordance with the standard indicated for that parameter in the table in Schedule 2 or an equivalent standard; or

(b) according to source as mentioned in Schedule 1.

EF_{ico_2oxec} is the amount worked out under subsection (2).

(2) For EF_{ico_2oxec} in subsection (1), work out as follows:

$$EF_{ico_2oxec} = \frac{EF_{ico_2ox,kg}}{EC_i} \times 1\,000$$

where:

$EF_{ico_2ox,kg}$ is the carbon dioxide emission factor for the type of fuel measured in kilograms of CO_2-e per kilogram of the type of fuel as worked out under subsection (3).

EC_i is the energy content factor of fuel type (***i***) as obtained under subsection (1).

(3) For $EF_{ico_2ox,kg}$ in subsection (2), estimate as follows:

$$EF_{ico_2ox,kg} = \left(\frac{C_{ar}}{100} - \frac{C_a \times A_{ar}}{(100 - C_a) \times 100}\right) \times 3.664$$

where:

C_{ar} is the percentage of carbon in fuel type (***i***), as received for the facility or as fired from the operation of the facility, worked out under subsection (4).

C_a is the amount of carbon in the ash estimated as a percentage of the as-sampled mass that is the weighted average of fly ash and ash by sampling and analysis in accordance with Subdivision 2.2.3.3.

A_{ar} is the amount of ash in fuel type (***i***) as a percentage of the as received or as fired mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

(4) For C_{ar}, in subsection (3), estimate as follows:

$$C_{ar} = \frac{C_{daf} \times (100 - M_{ar} - A_{ar})}{100}$$

where:

C_{daf} is the amount of carbon in fuel type (***i***) as a percentage of the dry ash-free mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

M_{ar} is the amount of moisture in fuel type (***i***) as a percentage of the as received or as fired mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

A_{ar} is the amount of ash in fuel type (***i***) as a percentage of the as received or as fired mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

Subdivision 2.2.3.3 Sampling and analysis for method 2 under sections 2.5 and 2.6

2.7 General requirements for sampling solid fuels

(1) A sample of the solid fuel must be derived from a composite of amounts of the solid fuel combusted.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard.

Note An appropriate standard is AS 4264.4—1996 *Coal and coke—Sampling – Determination of precision and bias.*

(5) The value obtained from the sample must only be used for the delivery period or consignment of the fuel for which it was intended to be representative.

2.8 General requirements for analysis of solid fuels

(1) A standard for analysis of a parameter of a solid fuel, and the minimum frequency of analysis of a solid fuel, is as set out in Schedule 2.

(2) A parameter of a solid fuel may also be analysed in accordance with a standard that is equivalent to a standard set out in Schedule 2.

(3) Analysis must be undertaken by an accredited laboratory or by a laboratory that meets requirements equivalent to those in AS ISO/IEC 17025:2005.

(4) If a delivery of fuel lasts for a month or less, analysis must be conducted on a delivery basis.

(5) However, if the properties of the fuel do not change significantly between deliveries over a period of a month, analysis may be conducted on a monthly basis.

(6) If a delivery of fuel lasts for more than a month, and the properties of the fuel do not change significantly before the next delivery, analysis of the fuel may be conducted on a delivery basis rather than monthly basis.

2.9 Requirements for analysis of furnace ash and fly ash

For furnace ash and fly ash, analysis of the carbon content must be undertaken in accordance with AS 3583.2—1991 *Determination of moisture content* and AS 3583.3—1991 *Determination of loss on ignition*.

2.10 Requirements for sampling for carbon in furnace ash

(1) This section applies to furnace ash sampled for its carbon content if the ash is produced from the operation of a facility that is constituted by a plant.

(2) A sample of the ash must be derived from representative operating conditions in the plant.

(3) A sample of ash may be collected:

(a) if contained in a wet extraction system — by using sampling ladles to collect it from sluiceways; or

(b) if contained in a dry extraction system — directly from the conveyor.

2.11 Sampling for carbon in fly ash

Fly ash must be sampled for its carbon content in accordance with a procedure set out in column 2 of an item in the following table, and at a frequency set out in column 3 for that item:

Item	Procedure	Frequency
1	At the outlet of a boiler air heater or the inlet to a flue gas cleaning plant using the isokinetic sampling method specified in AS 4323.1—1995 and AS 4323.2—1995	Every 2 years, and as a function of load
2	By using standard industry 'cegrit' extraction equipment	Every year, and as a function of load
3	By collecting fly ash from: (a) the fly ash collection hoppers of a flue gas cleaning plant; or (b) downstream of fly ash collection hoppers from ash silos or sluiceways	Once a year
4	From on-line carbon in ash analysers using sample extraction probes and infrared analysers	Every 2 years, and as a function of load

Division 2.2.4 Method 3 — Solid fuels

2.12 Method 3 — solid fuels using oxidation factor or an estimated oxidation factor

(1) For subparagraph 2.3 (1) (a) (iii) and subject to this section, method 3 is the same as method 2 whether using the oxidation factor under section 2.5 or using an estimated oxidation factor under section 2.6.

(2) In applying method 2 as mentioned in subsection (1), solid fuels must be sampled in accordance with the appropriate standard mentioned in the table in subsection (3).

(3) A standard for sampling a solid fuel mentioned in column 2 of an item in the following table is as set out in column 3 for that item:

Item	Fuel	Standard
1	Black coal (other than that used to produce coke)	AS 4264.1—1995
2	Brown coal	AS 4264.3—1996
3	Coking coal (metallurgical coal)	AS 4264.1—1995
4	Brown coal briquettes	AS 4264.3—1996
5	Coke oven coke	AS 4264.2—1996

Item	Fuel	Standard
6	Coal tar	
7	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	CEN/TS 14778 - 1:2006 CEN/TS 15442:2006
8	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006
9	Dry wood	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006
10	Green and air dried wood	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006
11	Sulphite lyes	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006
12	Bagasse	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006
13	Primary solid biomass other than items 9 to 12 and 14 to 15	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006
14	Charcoal	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006
15	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	CEN/TS 14778 - 1:2005 CEN/TS 15442:2006

(4) A solid fuel may also be sampled in accordance with a standard that is equivalent to a standard set out in the table in subsection (3).

Note The analysis is carried out in accordance with the same requirements as for method 2.

Division 2.2.5 Measurement of consumption of solid fuels

2.13 Purpose of Division

This Division sets out how quantities of solid fuels combusted from the operation of a facility are to be estimated for the purpose of working out the emissions released from the combustion of that fuel.

2.14 Criteria for measurement

For the purposes of calculating the amount of solid fuel combusted from the operation of a facility during a year and, in particular, for Q_i in sections 2.4, 2.5 and 2.6, the quantity of combustion must be estimated using one of the following criteria:

(a) the amount of the solid fuel delivered for the facility during the year as evidenced by invoices issued by the vendor of the fuel (***criterion A***);

(b) as provided in section 2.15 (***criterion AA***);

(c) as provided in section 2.16 (***criterion AAA***);

(d) as provided in section 2.17 (***criterion BBB***).

2.15 Indirect measurement at point of consumption — criterion AA

(1) For paragraph 2.14 (b), criterion AA is the amount of the solid fuel combusted from the operation of the facility during a year based on amounts delivered for the facility during the year as adjusted for the estimated change in the quantity of the stockpile of the fuel for the facility during the year.

(2) The volume of solid fuel in the stockpile may be measured using aerial or general survey in accordance with industry practice.

(3) The bulk density of the stockpile must be measured in accordance with:

(a) the procedure in ASTM D/6347/D 6347M-99; or

(b) the following procedure:

Step 1 If the mass of the stockpile:

(a) does not exceed 10% of the annual solid fuel combustion from the operation of a facility — extract a sample from the stockpile using a mechanical auger in accordance with ASTM D 4916-89; or

(b) exceeds 10% of the annual solid fuel combustion — extract a sample from the stockpile by coring.

Step 2 Weigh the mass of the sample extracted.

Step 3 Measure the volume of the hole from which the sample has been extracted.

Step 4 Divide the mass obtained in step 2 by the volume measured in step 3.

(4) Quantities of solid fuel delivered for the facility must be evidenced by invoices issued by the vendor of the fuel.

2.16 Direct measurement at point of consumption — criterion AAA

(1) For paragraph 2.14 (c), criterion AAA is the measurement during a year of the solid fuel combusted from the operation of the facility.

(2) The measurement must be carried out either:

(a) at the point of combustion using measuring equipment calibrated to a measurement requirement; or

(b) at the point of sale using measuring equipment calibrated to a measurement requirement.

(3) Paragraph (2) (b) only applies if:

(a) the change in the stockpile of the fuel for the facility for the year is less than 1% of total combustion on average for the facility during the year; and

(b) the stockpile of the fuel for the facility at the beginning of the year is less than 5% of total combustion for the year.

2.17 Simplified consumption measurements — criterion BBB

For paragraph 2.14 (d), criterion BBB is the estimation of the solid fuel combusted during a year from the operation of the facility in accordance with industry practice if:

(a) the acquisition of the fuel does not involve a commercial transaction; and

(b) the equipment used to measure combustion of the fuel is not calibrated to a measurement requirement.

Note An estimate obtained using industry practice must be consistent with the principles in section 1.13.

Part 2.3 Emissions released from the combustion of gaseous fuels

Division 2.3.1 Preliminary

2.18 Application

This Part applies to UNFCCC category 1.A — gaseous fuels.

2.19 Available methods

(1) Subject to section 1.18, for estimating emissions released from the combustion of a gaseous fuel consumed from the operation of a facility during a year:

(a) one of the following methods must be used for estimating emissions of carbon dioxide:
  (i) method 1 under section 2.20;
  (ii) method 2 under section 2.21;
  (iii) method 3 under section 2.26;
  (iv) method 4 under Part 1.3; and

(b) one of the following methods must be used for estimating emissions of methane:
  (i) method 1 under section 2.20;
  (ii) method 2 under section 2.27; and

(c) method 1 under section 2.20 must be used for estimating emissions of nitrous oxide.

Note The combustion of gaseous fuels releases emissions of carbon dioxide, methane and nitrous oxide. Method 1 is used to estimate emissions of each of these gases. There is no method 3 or 4 for emissions of methane and no method 2, 3 or 4 for emissions of nitrous oxide.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

(3) If the primary activity of the facility is electricity generation (ANZSIC industry classification and code 2611) method 1 must not be used for estimating carbon dioxide.

Division 2.3.2 Method 1 — emissions of carbon dioxide, methane and nitrous oxide

2.20 Method 1 — emissions of carbon dioxide, methane and nitrous oxide

(1) For subparagraphs 2.19 (1) (a) (i) and (b) (i) and paragraph 2.19 (1) (c), method 1 for estimating emissions of carbon dioxide, methane and nitrous oxide is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1\ 000}$$

where:

E$_{ij}$ is the emissions of gas type (***j***), being carbon dioxide, methane or nitrous oxide, from each gaseous fuel type (***i***) released from the operation of the facility during the year measured in CO_2-e tonnes.

Q$_i$ is the quantity of fuel type (***i***) combusted from the operation of the facility during the year measured in cubic metres or gigajoules and estimated under Division 2.3.6.

EC$_i$ is the energy content factor of fuel type (***i***) specified in Part 2 of Schedule 1 and measured in gigajoules per cubic metre.

EF$_{ijoxec}$ is the emission factor for each gas type (***j***) released during the year (which includes the effect of an oxidation factor) measured in kilograms CO_2-e per gigajoule of fuel type (***i***) according to source as mentioned in Part 2 of Schedule 1.

(2) If ***Q$_i$*** is measured in gigajoules, then ***EC$_i$*** is 1.

Note The combustion of gaseous fuels releases emissions of carbon dioxide, methane and nitrous oxide.

Division 2.3.3 Method 2 — emissions of carbon dioxide from the combustion of gaseous fuels

Subdivision 2.3.3.1 Method 2 — emissions of carbon dioxide from the combustion of gaseous fuels

2.21 Method 2 — emissions of carbon dioxide from the combustion of gaseous fuels

(1) For subparagraph 2.19 (1) (a) (ii), method 2 for estimating emissions of carbon dioxide is:

$$E_{i,\,CO2} = \frac{(Q_i \times EC_i \times EF_{i\,CO2ox,ec})}{1\,000}$$

where:

$E_{i,co2}$ is emissions of carbon dioxide released from fuel type (***i***) combusted from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) combusted from the operation of the facility during the year measured in cubic metres or gigajoules and estimated under Division 2.3.6.

EC_i is the energy content factor of fuel type (***i***) measured in gigajoules per cubic metre:

(a) estimated from analysis under Subdivision 2.3.3.2; or

(b) according to source as mentioned in Schedule 1.

$EF_{iCO2ox,ec}$ is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms CO_2-e per gigajoule and calculated in accordance with section 2.22.

(2) If Q_i is measured in gigajoules, then EC_i is 1.

(3) Method 2 requires gaseous fuels to be sampled and analysed in accordance with the requirements in sections 2.23, 2.24 and 2.25.

2.22 Calculation of emission factors from combustion of gaseous fuel

(1) For section 2.21, the emission factor **$EF_{i,CO2,ox,ec}$** from the combustion of fuel type (***i***) must be calculated from information on the composition of each component gas type (***y***) and must first estimate **$EF_{i,CO2,,ox,kg}$** in accordance with the following formula:

$$EF_{i,\,CO2,ox,kg} = \Sigma_y \left[\left(\frac{mol_y\% \times \left(\frac{mw_y}{V}\right) \times 100}{d_{y,\,total}} \right) \times \left(\frac{44.010 \times f_y \times OF_g}{(mw_y \times 100)} \right) \right]$$

where:

$EF_{i,CO2,ox,kg}$ is the carbon dioxide emission factor for fuel type (***i***), incorporating the effects of a default oxidation factor expressed as kilograms of carbon dioxide per kilogram of fuel.

$mol_y\%$, for each component gas type (***y***), is that gas type's share of 1 mole of fuel type (***i***), or that gas type's share of the total volume of fuel type (***i***), expressed as a percentage.

mw_y, for each component gas type (***y***), is the molecular weight of the component gas type (***y***) measured in kilograms per kilomole.

V is the volume of 1 kilomole of the gas at standard conditions-and equal to 23.6444 cubic metres.

$d_{y,\,total}$ is as set out in subsection (2).

f_y for each component gas type (***y***), is the number of carbon atoms in a molecule of the component gas type (***y***).

OF_g is the oxidation factor 0.995 applicable to gaseous fuels.

(2) For subsection (1), the factor **$d_{y,\,total}$** is worked out using the following formula:

$$d_{y,\,total} = \Sigma_y\, mol_y\% \times \left(\frac{mw_y}{V}\right)$$

where:

$mol_y\%$, for each component gas type (***y***), is that gas type's share of 1 mole of fuel type (***i***), or that gas type's share of the total volume of fuel type (***i***), expressed as a percentage.

mw_y, for each component gas type (***y***), is the molecular weight of the component gas type (***y***) measured in kilograms per kilomole.

(3) For subsection (1), the molecular weight and number of carbon atoms in a molecule of each component gas type (***y***) mentioned in column 2 of an item in the following table is as set out in columns 3 and 4, respectively, for the item:

Item	**Component gas y**	**Molecular Wt (kg/kmole)**	**Number of carbon atoms in component molecules**
1	Methane	16.043	1
2	Ethane	30.070	2
3	Propane	44.097	3
4	Butane	58.123	4
5	Pentane	72.150	5
6	Carbon monoxide	28.016	1
7	Hydrogen	2.016	0
8	Hydrogen sulphide	34.082	0
9	Oxygen	31.999	0
10	Water	18.015	0
11	Nitrogen	28.013	0
12	Argon	39.948	0
13	Carbon dioxide	44.010	1

(4) The carbon dioxide emission factor $EF_{i\,CO2,ox,ec}$ derived from the calculation in subsection (1) must be expressed in terms of kilograms of carbon dioxide per gigajoule calculated using the following formula:

$$EF_{i\,CO2,ox,ec} = EF_{i,\,CO2ox,\,kg} \div \left(\frac{EC_i}{C_i}\right)$$

where:

EC_i is the energy content factor of the fuel type (***i***) as obtained under section 2.21 and expressed in gigajoules per cubic metre.

C_i is the density of fuel type (***i***) expressed in kilograms of fuel per cubic metre.

Subdivision 2.3.3.2 Sampling and analysis

2.23 General requirements for sampling under method 2

(1) A sample of the gaseous fuel must be derived from a composite of amounts of the gaseous fuel combusted.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the samples must only be used for the delivery period, usage period or consignment of the gaseous fuel for which it was intended to be representative.

2.24 Standards for analysing samples of gaseous fuels

(1) Samples of gaseous fuels of a type mentioned in column 2 of an item in the following table must be analysed in accordance with one of the standards mentioned in:

(a) for analysis of energy content — column 3 for that item; and

(b) for analysis of gas composition — column 4 for that item.

Item	Fuel type	Energy content	Gas Composition
1	Natural gas if distributed in a pipeline	ASTM D 1826 — 94 (2003) ASTM D 7164 — 05 ASTM 3588 — 98 (2003) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00

Item	Fuel type	Energy content	Gas Composition
2	Coal seam methane that is captured for combustion	ASTM D 1826 — 94 (2003) ASTM D 7164 — 05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
3	Coal mine waste gas that is captured for combustion	ASTM D 1826 – 94 (2003) ASTM D 7164 – 05 ASTM 3588 — 98 (2003) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 – 03 ASTM D 1946 – 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
4	Compressed natural gas	ASTM 3588 — 98 (2003)	N/A
5	Unprocessed natural gas	ASTM D 1826 — 94 (2003) ASTM D 7164 — 05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00

Item	Fuel type	Energy content	Gas Composition
6	Ethane	ASTM D 3588 – 98 (2003) IS0 6976:1995	ASTM D 1945 – 03 ASTM D 1946 – 90 (2006)
7	Coke oven gas	ASTM D 3588 — 98 (2003) ISO 6976:1995	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006)
8	Blast furnace gas	ASTM D 3588 — 98 (2003) ISO 6976:1995	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006)
9	Town gas	ASTM D 1826 — 94 (2003) ASTM D 7164 — 05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
10	Liquefied natural gas	ISO 6976:1995	ASTM D 1945 – 03 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002)

Item	Fuel type	Energy content	Gas Composition
11	Landfill biogas that is captured for combustion	ASTM D 1826 — 94 (2003) ASTM D 7164 — 05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
12	Sludge biogas that is captured for combustion	ASTM D 1826 – 94 (2003) ASTM D 7164 – 05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 – 03 ASTM D 1946 – 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
13	A biogas that is captured for combustion, other than those mentioned in items 11 and 12	ASTM D 1826 — 94 (2003) ASTM D 7164 — 05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172 — 96	ASTM D 1945 — 03 ASTM D 1946 — 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00

(2) A gaseous fuel mentioned in column 2 of an item in the table in subsection (1) may also be analysed in accordance with a standard that is equivalent to a standard set out in column 3 and 4 of the item.

(3) The analysis must be undertaken by an accredited laboratory or by a laboratory that meets requirements that are equivalent to the requirements in AS ISO/IEC 17025:2005.

(4) The density of a gaseous fuel mentioned in column 2 of an item in the table in subsection (1) must be analysed in accordance with ISO 6976:1995 or in accordance with a standard that is equivalent to that standard.

2.25 Frequency of analysis

Gaseous fuel of a type mentioned in column 2 of an item in the following table must be analysed for the parameter mentioned in column 3 for that item at least at the frequency mentioned in column 4 for that item.

Item	Fuel	Parameter	Frequency
1	Pipeline quality gases	Gas composition	Monthly
		Energy content	Monthly — if category 1 or 2 gas measuring equipment is used Continuous — if category 3 or 4 gas measuring equipment is used
2	All other gases	Gas composition Energy content	Monthly, unless the reporting corporation certifies in writing that such frequency of analysis will cause significant hardship or expense in which case the analysis may be undertaken at a frequency that will allow an unbiased estimate to be obtained

Note The table in section 2.31 sets out the categories of gas measuring equipment.

Division 2.3.4 Method 3 — emissions of carbon dioxide released from the combustion of gaseous fuels

2.26 Method 3 — emissions of carbon dioxide from the combustion of gaseous fuels

(1) For subparagraph 2.19 (1) (a) (iii) and subject to subsection (2), method 3 for estimating emissions of carbon dioxide is the same as method 2 under section 2.21.

(2) In applying method 2 under section 2.21, gaseous fuels must be sampled in accordance with a standard specified in the table in subsection (3).

(3) A standard for sampling a gaseous fuel mentioned column 2 of an item in the following table is the standard specified in column 3 for that item.

Item	Gaseous fuel	Standard
1	Natural gas if distributed in a pipeline	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
2	Coal seam methane that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
3	Coal mine waste gas that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
4	Compressed natural gas	ASTM F 307–02 (2007)
5	Unprocessed natural gas	ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
6	Ethane	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003)
7	Coke oven gas	ISO 10715 -1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003)
8	Blast furnace gas	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003)
9	Town gas	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
10	Liquefied natural gas	ISO 8943:2007

Item	Gaseous fuel	Standard
11	Landfill biogas that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
12	Sludge biogas that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
13	A biogas that is captured for combustion, other than those mentioned in items 11 and 12	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05

(4) A gaseous fuel mentioned in column 2 of an item in the table in subsection (3) may also be sampled in accordance with a standard that is equivalent to a standard specified in column 3 for that item.

Division 2.3.5 Method 2 — emissions of methane from the combustion of gaseous fuels

2.27 Method 2 —emissions of methane from the combustion of gaseous fuels

(1) For subparagraph 2.19 (1) (b) (ii) and subject to subsection (2), method 2 for estimating emissions of methane is the same as method 1 under section 2.20.

(2) In applying method 1 under section 2.20, the emission factor EF_{ijoxec} is to be obtained by using the equipment type emission factors set out in Volume 2, section 2.3.2.3 of the 2006 IPCC Guidelines corrected to gross calorific values.

Division 2.3.6 Measurement of quantity of gaseous fuels

2.28 Purpose of Division

This Division sets out how quantities of gaseous fuels combusted from the operation of a facility are to be estimated for the purpose of working out the emissions released from the combustion of that fuel.

2.29 Criteria for measurement

(1) For the purposes of calculating the combustion of gaseous fuel from the operation of a facility for a year and, in particular, for ***Q_i*** in sections 2.20 and 2.21, the combustion must be estimated using one of the following criteria:

(a) the amount of gaseous fuel delivered for the facility during a year as evidenced by invoices issued by the vendor of the fuel (***criterion A***);

(b) as provided in section 2.30 (***criterion AA***);

(c) as provided in section 2.31 (***criterion AAA***);

(d) as provided in section 2.38 (***criterion BBB***).

(2) For paragraph (1) (a), the amount of gaseous fuel delivered must be expressed in cubic metres or gigajoules.

2.30 Indirect measurement at point of consumption — criterion AA

For paragraph 2.29 (1) (b), criterion AA is the amount of a gaseous fuel combusted from the operation of the facility during the year based on amounts delivered during the year (evidenced by invoices) as adjusted for the estimated change in the quantity of the stockpile of the fuel for the facility during the year.

2.31 Direct measurement at point of consumption — criterion AAA

(1) For paragraph 2.29 (1) (c), criterion AAA is the measurement during the year of a gaseous fuel combusted from the operation of the facility at the point of combustion.

(2) In measuring the quantity of gaseous fuel at the point of combustion, the quantities of gas must be measured:

(a) using volumetric measurement in accordance with:

  (i) for gases generally — section 2.32; and

  (ii) for supercompressed gases — section 2.33; and

(b) using gas measuring equipment that complies with section 2.34.

(3) The measurement must be either:

(a) carried out using measuring equipment that:

  (i) is in a category specified in column 2 of an item in the table in subsection (4) according to the maximum daily quantity of gas combusted specified in column 3 for that item from the operation of the facility; and

  (ii) is in a category specified in column 2 of an item in the table and complies with the transmitter and accuracy requirements for that equipment specified in column 4 for that item; or

(b) carried out at the point of sale of the gaseous fuels using measuring equipment that complies with paragraph (a).

(4) For subsection (3), the table is as follows:

Item	Gas measuring equipment category	Maximum daily quantity of gas combusted GJ/day	Transmitter and accuracy requirements (% of range)
1	1	0–1750	Pressure <±0.25% Diff. pressure <±0.25% Temperature <±0.50%
2	2	1751–3500	Pressure <±0.25% Diff. pressure <±0.25% Temperature <±0.50%
3	3	3501–17500	Smart transmitters: Pressure <±0.10% Diff. pressure <±0.10% Temperature <±0.25%
4	4	17501 or more	Smart transmitters: Pressure <±0.10% Diff. pressure <±0.10% Temperature <±0.25%

(5) Paragraph (3) (b) only applies if:

(a) the change in the stockpile of the fuel for the facility for the year is less than 1% of total consumption on average for the facility during the year; and

(b) the stockpile of the fuel for the facility at the beginning of the year is less than 5% of total consumption of the fuel from the operation of the facility during the year.

2.32 Volumetric measurement — general

(1) For paragraph 2.31 (2) (a), volumetric measurement must be in cubic metres at standard conditions.

(2) The volumetric measurement is to be calculated using a flow computer that measures and analyses flow signals, relative density and gas composition at the delivery location of the gaseous fuel.

(3) The volumetric flow rate must be continuously recorded and integrated using an integration device that is isolated from the flow computer in such a way that if the computer fails, the integration device will retain the last reading, or the previously stored information, that was on the computer immediately before the failure.

(4) Subject to subsection (5), all measurements, calculations and procedures used in determining volume (except for any correction for deviation from the ideal gas law) must be made in accordance with the instructions contained in the following:

(a) for orifice plate measuring systems — the publication entitled *American Gas Report No. 3* published by the American Gas Association or Parts 1 to 4 of the publication entitled *API 14.3* published by the American Petroleum Institute;

(b) for turbine measuring systems — the publication entitled *American Gas Association Transmission Measurement Committee Report No. 7* published by the American Gas Association;

(c) for positive displacement measuring systems — ANSI B109.3—1986.

(5) Measurements, calculations and procedures used in determining volume may also be made in accordance with an equivalent internationally recognised documentary standard or code.

Note New Zealand standard NZS 5259:1999 is an example of an appropriate internationally recognised code.

(6) Measurements must comply with units of measurement required by or under the *National Measurement Act 1960*.

(7) ***Standard conditions*** means:

(a) air pressure of 101.323 kilopascals; and

(b) air temperature of 15.0 degrees celsius; and

(c) air density of 1.225 kilograms per cubic metre.

2.33 Volumetric measurement — super-compressed gases

(1) This section applies for subparagraph 2.31 (2) (a) (ii).

(2) If, in determining volume in relation to super-compressed gases, it is necessary to correct for deviation from the ideal gas law, the correction must be determined using the relevant method contained in the publication entitled *American Gas Association Transmission Measurement Committee Report No. 8 (1992) Super-compressibility* published by the American Gas Association.

(3) The measuring equipment used must calculate super-compressibility by:

(a) if the measuring equipment is category 3 or 4 equipment in accordance with the table in section 2.31 — using composition data; or

(b) if the measuring equipment is category 1 or 2 equipment in accordance with the table in section 2.31 — using an alternative method set out in the publication entitled *American Gas Association Transmission Measurement Committee Report No. 8 (1992) Super-compressibility* published by the American Gas Association.

2.34 Gas measuring equipment — requirements

For paragraph 2.31 (2) (b), gas measuring equipment that is category 3 or 4 equipment in accordance with column 2 of the table in section 2.31 must comply with the following requirements:

(a) if the equipment uses flow devices — the requirements relating to flow devices set out in section 2.35;

(b) if the equipment uses flow computers — the requirement relating to flow computers set out in section 2.36;

(c) if the equipment uses gas chromatographs— the requirements relating to chromatographs set out in section 2.37.

2.35 Flow devices — requirements

(1) If the measuring equipment has flow devices that use orifice measuring systems, the flow devices must be constructed in a manner that ensures that the maximum uncertainty of the discharge coefficient is not greater than ±1.5%.

Note The publication entitled *American Gas Association Report No. 3*, published by the American Gas Association, sets out a manner that ensures that the maximum uncertainty of the discharge coefficient is not greater than ±1.5%.

(2) If the measuring equipment has flow devices that use turbine measuring systems, the flow devices must be installed in a manner that ensures that the maximum uncertainty of the flow measurement is not greater than ±1.5%.

Note The publication entitled *American Gas Association Transmission Measurement Committee Report No. 8 (1992) Super-compressibility*, published by the American Gas Association, sets out a manner that ensures that the maximum uncertainty of the flow measurement is not greater than ±1.5%.

(3) If the measuring equipment has flow devices that use positive displacement measuring systems, the flow devices must be installed in a manner that ensures that the maximum uncertainty of flow is ±1.5%.

Note ANSI B109.3—1986 sets out a manner for installation that ensures that the maximum uncertainty of flow is ±1.5%.

(4) If the measuring equipment uses any other type of flow device, the maximum uncertainty of flow measurement must not be greater than ±1.5%.

(5) All flow devices that are used by measuring equipment of a category specified in column 2 of the table in section 2.31 must, wherever possible, be calibrated for pressure, differential pressure and temperature in accordance with the requirements specified in column 4 for the category of equipment specified in column 2 for that item. The calibrations must take into account the effects of static pressure and ambient temperature.

2.36 Flow computers — requirements

For paragraph 2.34 (b), the requirement is that the flow computer that is used by the equipment for measuring purposes must record the instantaneous values for all primary measurement inputs and must also record the following outputs:

(a) instantaneous corrected volumetric flow;

(b) cumulative corrected volumetric flow;

(c) for turbine and positive displacement metering systems — instantaneous uncorrected volumetric flow;

(d) for turbine and positive displacement metering systems — cumulative uncorrected volumetric flow;

(e) super-compressibility factor.

2.37 Gas chromatographs

For paragraph 2.34 (c), the requirements are that gas chromatographs used by the measuring equipment must:

(a) be factory tested and calibrated using a measurement standard produced by gravimetric methods and traceable to Australian units of measurement required by or under the *National Measurement Act 1960*; and

(b) perform gas composition analysis with an accuracy of ±0.15% for use in calculation of gross calorific value and ±0.25% for calculation of relative density; and

(c) include a mechanism for re-calibration against a certified reference gas.

2.38 Simplified consumption measurements — criterion BBB

(1) For paragraph 2.29 (1) (d), criterion BBB is the estimation of gaseous fuel in accordance with industry practice if:

(a) the acquisition of the gaseous fuel does not involve a commercial transaction; and

(b) the measuring equipment used to estimate consumption of the fuel does not meet the requirements of criterion AAA.

(2) For sources of landfill gas captured for the purpose of combustion for the production of electricity:

(a) the energy content of the captured landfill gas may be estimated by assuming that measured electricity dispatched for sale (sent out generation) represents 36% of the energy content of all fuel used to produce electricity; and

(b) the quantity of landfill gas captured in cubic metres may be derived from the energy content of the relevant gas set out in Part 2 of Schedule 1.

Part 2.4 Emissions released from the combustion of liquid fuels

Division 2.4.1 Preliminary

2.39 Application

This Part applies to UNFCCC category 1.A — liquid fuels.

2.40 Available methods

(1) Subject to section 1.18, for estimating emissions released from the combustion of a liquid fuel consumed from the operation of a facility during a year:

(a) one of the following methods must be used for estimating emissions of carbon dioxide:

  (i) method 1 under section 2.41;
  (ii) method 2 under section 2.42;
  (iii) method 3 under section 2.47;
  (iv) method 4 under Part 1.3; and

(b) one of the following methods must be used for estimating emissions of methane and nitrous oxide:

  (i) method 1 under section 2.41;
  (ii) method 2 under section 2.48.

(2) Under paragraph (1) (b), the same method must be used for estimating emissions of methane and nitrous oxide.

(3) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Note The combustion of liquid fuels releases emissions of carbon dioxide, methane and nitrous oxide. Method 1 may be used to estimate emissions of each of these gases. There is no method 3 or 4 for emissions of methane or nitrous oxide.

Division 2.4.2 Method 1 — emissions of carbon dioxide, methane and nitrous oxide

2.41 Method 1 — emissions of carbon dioxide, methane and nitrous oxide

For subparagraphs 2.40 (1) (a) (i) and (b) (i), method 1 for estimating emissions of carbon dioxide, methane and nitrous oxide is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1\,000}$$

where:

E_{ij} is the emissions of gas type (***j***), being carbon dioxide, methane or nitrous oxide, released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) combusted from the operation of the facility for:

(a) stationary energy purposes; and

(b) transport energy purposes;

during the year measured in kilolitres and estimated under Division 2.4.6.

EC_i is the energy content factor of fuel type (***i***) measured as energy content in gigajoules per kilolitre according to source as mentioned in:

(a) for stationary energy purposes — Part 3 of Schedule 1; and

(b) for transport energy purposes — Division 4.1 of Schedule 1.

EF_{ijoxec} is the emission factor for each gas type (***j***) released from the operation of the facility during the year (which includes the effect of an oxidation factor) measured in kilograms CO_2-e per gigajoule of fuel type (***i***) according to source as mentioned in:

(a) for stationary energy purposes — Part 3 of Schedule 1; and

(b) for transport energy purposes — Division 4.1 of Schedule 1.

Note The combustion of liquid fuels produces emissions of carbon dioxide, methane and nitrous oxide.

Division 2.4.3 Method 2 — emissions of carbon dioxide released from the combustion of liquid fuels

Subdivision 2.4.3.1 Method 2 — emissions of carbon dioxide released from the combustion of liquid fuels

2.42 Method 2 — emissions of carbon dioxide from the combustion of liquid fuels

(1) For subparagraph 2.40 (1) (a) (ii), method 2 for estimating emissions of carbon dioxide is:

$$E_{i,\,CO2} = \frac{(Q_i \times EC_i \times EF_{i\,CO2ox,ec})}{1000}$$

where:

$E_{i,CO2}$ is the emissions of carbon dioxide released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) combusted from the operation of the facility during the year measured in kilolitres .

EC_i is the energy content of fuel type (***i***) measured in gigajoules per kilolitre:

(a) estimated from analysis under Subdivision 2.3.3.2; or

(b) according to source as mentioned in Schedule 1.

$EF_{iCO2ox,ec}$ is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms of CO_2-e per gigajoule.

(2) Method 2 requires liquid fuels to be sampled and analysed in accordance with the requirements in sections 2.44, 2.45 and 2.46.

2.43 Calculation of emission factors from combustion of liquid fuel

(1) For section 2.42, the emission factor $EF_{iCO2ox,ec}$ from the combustion of fuel type (***i***) must allow for oxidation effects and must first estimate $EF_{i,co2,ox,kg}$ in accordance with the following formula:

$$EF_{i,\,co2,ox,kg} = \frac{C_a}{100} \times OF_i \times 3.664$$

where:

C_a is the carbon in the fuel expressed as a percentage of the mass of the fuel as received, as sampled, or as fired, as the case may be.

OF_i is the oxidation factor 0.99 applicable to liquid fuels.

Note 3.664 converts tonnes of carbon to tonnes of carbon dioxide.

(2) The emission factor derived from the calculation in subsection (1), must be expressed in kilograms of carbon dioxide per gigajoule calculated using the following formula:

$$EF_{i,\ co2,ox,ec} = EF_{i,\ co2,ox,kg} \div \left(\frac{EC_i}{C_i} \right)$$

where:

EC_i is the energy content factor of fuel type (***i***) as obtained under subsection 2.42 (1) and expressed in gigajoules per kilolitre.

C_i is the density of the fuel expressed in kilograms of fuel per thousand litres.

Subdivision 2.4.3.2 Sampling and analysis

2.44 General requirements for sampling under method 2

(1) A sample of the liquid fuel must be derived from a composite of amounts of the liquid fuel.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the samples must only be used for the delivery period or consignment of the liquid fuel for which it was intended to be representative.

2.45 Standards for analysing samples of liquid fuels

(1) Samples of liquid fuel of a type mentioned in column 2 of an item in the following table must be analysed in accordance with a standard (if any) mentioned in:

(a) for energy content analysis — column 3 for that item; and
(b) for carbon analysis — column 4 for that item; and
(c) density analysis — column 5 for that item.

Item	Fuel	Energy Content	Carbon	Density
1	Petroleum based oils (other than petroleum based oils used as fuel)	N/A	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
2	Petroleum based greases	N/A	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
3	Crude oil including crude oil condensates	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
4	Other natural gas liquids	N/A	N/A	ASTM D 1298 – 99 (2005)
5	Gasoline (other than for use as fuel in an aircraft)	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005)
6	Gasoline for use as fuel in an aircraft	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005)
7	Kerosene (other than for use as fuel in an aircraft)	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005)
8	Kerosene for use as fuel in an aircraft	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005)
9	Heating oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
10	Diesel oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)

Item	Fuel	Energy Content	Carbon	Density
11	Fuel oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
12	Liquefied aromatic hydrocarbons	N/A	N/A	ASTM D 1298 – 99 (2005)
13	Solvents if mineral turpentine or white spirits	N/A	N/A	N/A
14	Liquefied Petroleum Gas	N/A	ISO 7941:1988	ISO 6578:1991 ISO 8973:1997
15	Naphtha	N/A	N/A	N/A
16	Petroleum coke	N/A	N/A	N/A
17	Refinery gas and liquids	N/A	N/A	N/A
18	Refinery coke	N/A	N/A	N/A
19	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 1and 2 (b) the petroleum based products mentioned in items 3 to 18	N/A	N/A	N/A
20	Biodiesel	N/A	N/A	N/A
21	Ethanol for use as a fuel in an internal combustion engine	N/A	N/A	N/A

Item	Fuel	Energy Content	Carbon	Density
22	Biofuels other than those mentioned in items 20 and 21	N/A	N/A	N/A

(2) A liquid fuel of a type mentioned in column 2 of an item in the table in subsection (1) may also be analysed for energy content, carbon and density in accordance with a standard that is equivalent to a standard mentioned in columns 3, 4 and 5 for that item.

(3) Analysis must be undertaken by an accredited laboratory or by a laboratory that meets requirements equivalent to those in AS ISO/IEC 17025:2005.

2.46 Frequency of analysis

Liquid fuel of a type mentioned in column 2 of an item in the following table must be analysed for the parameter mentioned in column 3 for that item at least at the frequency mentioned in column 4 for that item.

Item	Fuel	Parameter	Frequency
1	All types of liquid fuel	Carbon	Quarterly or by delivery of the fuel
2	All types of liquid fuel	Energy	Quarterly or by delivery of the fuel

Division 2.4.4 Method 3 — emissions of carbon dioxide released from the combustion of liquid fuels

2.47 Method 3 — emissions of carbon dioxide from the combustion of liquid fuels

(1) For subparagraph 2.40 (1) (a) (iii) and subject to this section, method 3 for estimating emissions of carbon dioxide is the same as method 2 under section 2.42.

(2) In applying method 2 under section 2.42, liquid fuels must be sampled in accordance with a standard specified in the table in subsection (3).

(3) A standard for sampling a liquid fuel of a type mentioned in column 2 of an item in the following table is specified in column 3 for that item.

item	Liquid Fuel	Standard
1	Petroleum based oils (other than petroleum based oils used as fuel)	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06
2	Petroleum based greases	
3	Crude oil including crude oil condensates	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
4	Other natural gas liquids	ASTM D1265 - 05
5	Gasoline (other than for use as fuel in an aircraft)	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
6	Gasoline for use as fuel in an aircraft	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
7	Kerosene (other than for use as fuel in an aircraft)	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
8	Kerosene for use as fuel in an aircraft	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
9	Heating oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
10	Diesel oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
11	Fuel oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
12	Liquefied aromatic hydrocarbons	ASTM D 4057 – 06
13	Solvents if mineral turpentine or white spirits	ASTM D 4057 – 06
14	Liquefied Petroleum Gas	ASTM D1265 - 05) ISO 4257:2001

item	Liquid Fuel	Standard
15	Naphtha	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06
16	Petroleum coke	ASTM D 4057 – 06
17	Refinery gas and liquids	ASTM D 4057 – 06
18	Refinery coke	ASTM D 4057 – 06
19	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 1 and 2; and (b) the petroleum based products mentioned in items 3 to 18	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06
20	Biodiesel	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
21	Ethanol for use as a fuel in an internal combustion engine	ASTM D 4057 – 06
22	Biofuels other than those mentioned in items 20 and 21	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)

(4) A liquid fuel may also be sampled in accordance with a standard that is equivalent to a standard set out in the table in subsection (3) in relation to that liquid fuel.

Division 2.4.5 Method 2 — emissions of methane and nitrous oxide from the combustion of liquid fuels

2.48 Method 2 — emissions of methane and nitrous oxide from the combustion of liquid fuels

(1) For subparagraph 2.40 (1) (b) (ii) and subject to subsection (2), method 2 for estimating emissions of methane and nitrous oxide is the same as method 1 under section 2.41.

(2) In applying method 1 in section 2.41, the emission factor $\boldsymbol{EF_{ijoxec}}$ is taken to be the emission factor set out in:

(a) for combustion of fuel by vehicles manufactured after 2004 — column 4 of the table in Division 4.2 of Part 4 of Schedule 1; and

(b) for combustion of fuel by trucks that meet the design standards mentioned in column 2 of the table in Division 4.3 of Part 4 of Schedule 1 — column 4 of the table in that Division.

Division 2.4.6 Measurement of quantity of liquid fuels

2.49 Purpose of Division

This Division sets out how quantities of liquid fuels combusted from the operation of a facility are to be estimated for the purpose of working out the emissions released from the combustion of that fuel.

2.50 Criteria for measurement

For the purposes of calculating the combustion of a liquid fuel from the operation of a facility for a year and, in particular, for $\boldsymbol{Q_i}$ in sections 2.41 and 2.42 the combustion must be estimated using one of the following criteria:

(a) the amount of liquid fuel delivered for the facility during a year as evidenced by invoices issued by the vendor of the fuel (***criterion A***);

(b) as provided in section 2.51 (***criterion AA***);

(c) as provided in section 2.52 (***criterion AAA***);

(d) as provided in section 2.53 (***criterion BBB***).

2.51 Indirect measurement at point of consumption — criterion AA

For paragraph 2.50 (b), criterion AA is the amount of the liquid fuel combusted from the operation of the facility during the year based on amounts delivered during the year (evidenced by invoices) as adjusted for the estimated change in the quantity of the stockpile of the fuel for the facility during the year.

2.52 Direct measurement at point of consumption — criterion AAA

(1) For paragraph 2.50 (c), criterion AAA is the measurement during the year of the liquid fuel combusted from the operation of the facility at the point of combustion.

(2) The measurement must be carried out:

(a) at the point of combustion at ambient temperatures and converted to standard temperatures, using measuring equipment calibrated to a measurement requirement; or

(b) at ambient temperatures and converted to standard temperatures, at the point of sale of the liquid fuel, using measuring equipment calibrated to a measurement requirement.

(3) Paragraph (2) (b) only applies if:

(a) the change in the stockpile of fuel for the facility for the year is less than 1% of total combustion on average for the facility during the year; and

(b) the stockpile of the fuel for the facility at the beginning of the year is less than 5% of total combustion from the operation of the facility for the year.

2.53 Simplified consumption measurements — criterion BBB

For paragraph 2.50 (d), criterion BBB is the estimation of the combustion of a liquid fuel for the year using accepted industry measuring devices or, in the absence of such measuring devices, in accordance with industry practice if:

(a) the acquisition of the fuel does not involve a commercial transaction; and

(b) the equipment used to measure consumption of the fuel is not calibrated to a measurement requirement.

Part 2.5 Emissions released from fuel use by certain industries

2.54 Application

This Part applies to UNFCCC Categories 1A.1.b, 1A.1.c and 1A.2.c — petroleum refining, solid fuel transformation (coke ovens) and petrochemical production.

Division 2.5.1 Energy — petroleum refining

2.55 Application

This Division applies to UNFCCC Category 1A.1.b — petroleum refining.

2.56 Methods

(1) If:

(a) the operation of a facility is constituted by petroleum refining; and

(b) the refinery combusts fuels for energy;

then the methods for estimating emissions during a year from that combustion are as provided in Parts 2.2, 2.3 and 2.4.

(2) The method for estimating emissions from the production of hydrogen by the petroleum refinery must be in accordance with the method set out in section 5 of the API Compendium.

(3) Fugitive emissions released from the petroleum refinery must be estimated using methods provided for in Chapter 3.

Division 2.5.2 Energy — manufacture of solid fuels (coke ovens)

2.57 Application

This Division applies to UNFCCC Category 1A.1.c — solid fuel transformation (coke ovens).

2.58 Methods

(1) If:

(a) a facility is constituted by the manufacture of solid fuel using coke ovens; and

(b) in the manufacture, fuels are combusted for energy;

then the methods for estimating emissions during a year from that combustion are provided in Part 4.3.

(2) These emissions are to be reported under this UNFCCC Category.

Division 2.5.3 Energy — petrochemical production

2.59 Application

This Division applies to Source UNFCCC Category 1A.2.c — petrochemical production (where fuel is consumed as a feedstock).

2.60 Available methods

(1) Subject to section 1.18 one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by an activity that is petrochemical production:

(a) method 1 under section 2.61;

(b) method 2 under section 2.62;

(c) method 3 under section 2.63;

(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

2.61 Method 1 — petrochemical production

Method 1, based on a carbon mass balance approach, is:

Step 1 Calculate the carbon content in all fuel types (***i***) delivered for the activity during the year as follows:

$$\Sigma_i \, CCF_i \times Q_i$$

where:

$\boldsymbol{\Sigma_i}$ means sum the carbon content values obtained for all fuel types (***i***).

$\boldsymbol{CCF_i}$ is the carbon content factor measured in tonnes of carbon for each tonne of fuel type (***i***) as mentioned in Schedule 3 consumed in the operation of the activity.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) delivered for the activity during the year measured in tonnes and estimated in accordance with criterion A in Divisions 2.2.5, 2.3.6 and 2.4.6.

Step 2 Calculate the carbon content in products (***p***) leaving the activity during the year as follows:

$$\Sigma_p \, CCF_p \times A_p$$

where:

Σ_p means sum the carbon content values obtained for all product types (***p***).

CCF_p is the carbon content factor measured in tonnes of carbon for each tonne of product (***p***).

A_p is the quantity of products produced (***p***) leaving the activity during the year measured in tonnes.

Step3 Calculate the carbon content in waste by-products ***(r)*** leaving the activity, other than as an emission of greenhouse gas, during the year as follows:

$$\Sigma_r \, CCF_r \times Y_r$$

where:

Σ_r means sum the carbon content values obtained for all waste by-product types (***r***).

CCF_r is the carbon content factor measured in tonnes of carbon for each tonne of waste by-product (***r***).

Y_r is the quantity of waste by-product (***r***) leaving the activity during the year measured in tonnes.

Step 4 Calculate the carbon content in the amount of the increase in stocks of inputs, products and waste by-products held within the boundary of the activity during the year as follows:

$$\Sigma_i \, CCF_i \times \Delta S_{qi} + \Sigma_p \, CCF_p \times \Delta S_{ap} + \Sigma_r \, CCF_r \times \Delta S_{yr}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

ΔS_{qi} is the increase in stocks of fuel type (***i***) for the activity and held within the boundary of the activity during the year measured in tonnes.

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

ΔS_{ap} is the increase in stocks of products produced ***(p)*** by the activity and held within the boundary of the activity during the year measured in tonnes.

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the increase in stocks of waste by-products (***r***) produced by the activity and held within the boundary of the activity during the year measured in tonnes.

Step 5 Calculate the emissions of carbon dioxide released from the activity during the year measured in CO_2-e tonnes as follows:

(a) add the amounts worked out under steps 2, 3 and 4 to work out a new amount (***amount A***)

(b) subtract amount A from the amount worked out under step 1 to work out a new amount (***amount B***);

(c) multiply amount B by 3.664 to work out the amount of emissions released from the activity during a year.

2.62 Method 2 — petrochemical production

(1) Method 2 is the same as method 1 but sampling and analysis of fuel types ***(i)*** is used to determine carbon content of the fuel.

(2) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, liquid or gaseous fuels.

2.63 Method 3— petrochemical production

(1) Method 3 is the same as method 1 but the sampling and analysis of fuel types ***(i)*** is used to determine carbon content of the fuel.

(2) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, liquid or gaseous fuels.

Part 2.6 Blended fuels

2.64 Purpose

This Part sets out how to determine the amounts of each kind of fuel that is in a blended fuel.

2.65 Application

This Part sets out how to determine the amount of each fuel type (***i***) that is in a blended fuel if that blended fuel is a solid fuel or a liquid fuel.

2.66 Blended solid fuels

(1) In determining the amounts of each kind of fuel that is in a blended solid fuel, a person may adopt the outcome of the sampling and analysis done by the manufacturer of the fuel if:

(a) the sampling has been done in accordance with subsections 2.12 (3) and (4); and

(b) the analysis has been done in accordance with one of the following standards or a standard that is equivalent to one of those standards:

(i) CEN/TS15440:2006;

(ii) ASTM D 6866-06a.

(2) The person may use his or her own sampling and analysis of the fuel if the sampling and analysis complies with the requirements of paragraphs (1) (a) and (b).

2.67 Blended liquid fuels

The person may adopt the manufacturer's determination of each kind of fuel that is in a blended liquid fuel or adopt the analysis arrived at after doing both of the following:

(a) sampling the fuel in accordance with a standard mentioned in subsections 2.47 (3) and (4);

(b) analysing the fuel in accordance with ASTM: D6866-06a or a standard that is equivalent to that standard.

Part 2.7 Estimation of energy for certain purposes

2.68 Amount of fuel consumed without combustion

For paragraph 4.22 (1) (b) of the Regulations:

(a) the energy is to be measured :

(i) for solid fuel — in tonnes estimated under Division 2.2.5; or

(ii) for gaseous fuel — in cubic metres estimated under Division 2.3.6; or

(iii) for liquid fuel — in kilolitres estimated under Division 2.4.6; and

(b) the reporting threshold is:

(i) for solid fuel —20 tonnes; or

(ii) for gaseous fuel —13 000 cubic metres; or

(iii) for liquid fuel —15 kilolitres.

Example

A fuel is consumed without combustion when it is used as a solvent or a flocculent, or as an ingredient in the manufacture of products such as paints, solvents or explosives.

2.69 Apportionment of fuel consumed as carbon reductant or feedstock and energy

(1) This section applies, other than for Division 2.5.3, if:

(a) a fuel type as provided for in a method is consumed from the operation of a facility as either a reductant or a feedstock; and

(b) the fuel is combusted for energy; and

(c) the equipment used to measure the amount of the fuel for the relevant purpose was not calibrated to a measurement requirement.

Note Division 2.5.3 deals with petrochemicals. For petrochemicals, all fuels, whether used as a feedstock, a reductant or combusted as energy are reported as energy.

(2) The amount of the fuel type consumed as a reductant or a feedstock may be estimated:

(a) in accordance with industry measuring devices or industry practice; or

(b) if it is not practicable to estimate as provided for in paragraph (a) — to be the whole of the amount of the consumption of that fuel type from the operation of the facility.

(3) The amount of the fuel type combusted for energy may be estimated as the difference between the total amount of the fuel type consumed from the operation of the facility and the estimated amount worked out under subsection (2).

2.70 Amount of energy consumed in a cogeneration process

(1) For subregulation 4.23 (3) of the Regulations and subject to subsection (3), the method is the efficiency method.

(2) The ***efficiency method*** is as described in the publication entitled *Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0* issued by the World Resource Institute and World Business Council for Sustainable Development.

(3) Where heat is to be used mainly for producing mechanical work, the work potential method may be used.

(4) The ***work potential method*** is as described in the publication entitled *Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0* issued by the World Resource Institute and World Business Council for Sustainable Development.

2.71 Apportionment of energy consumed for electricity, transport and for stationary energy

Subject to section 2.70, the amount of fuel type (***i***) consumed by a reporting corporation that is apportioned between electricity generation, transport (excluding international bunker fuels) and other stationary energy purposes may be determined using the corporation's records if the records are based on the measurement equipment used by the corporation to measure consumption of the fuel types.

Chapter 3 Fugitive emissions from fuels (UNFCCC Category 1.B)

Part 3.1 Preliminary

3.1 Outline of Chapter

This Chapter provides for UNFCCC Category 1.B — fugitive emissions from fuels, as follows:

(a) Part 3.2 provides for fugitive emissions from coal mining — UNFCCC Category 1.B.1;

(b) Part 3.3 provides for fugitive emissions from oil and natural gas activities — UNFCCC Category 1.B.2.

Note The above UNFCCC categories include emissions from flaring and other combustion of fuels for a purpose other than producing energy.

Part 3.2 Coal mining

Division 3.2.1 Preliminary

3.2 Outline of Part

This Part provides for UNFCCC Category 1.B.1 — fugitive emissions from coal mining, as follows:

(a) UNFCCC Category 1.B.1.a.i — underground mining activities (see Division 3.2.2);

(b) UNFCCC Category 1.B.1.a.ii — open cut mining activities (see Division 3.2.3);

(c) UNFCCC Category 1.B.1.c — decommissioned underground mines (see Division 3.2.4).

Division 3.2.2 Underground mines

Subdivision 3.2.2.1 Preliminary

3.3 Application

This Division applies to UNFCCC Category 1.B.1.a.i — fugitive emissions from underground mining activities (other than decommissioned underground mines).

3.4 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by underground mining activities (other than decommissioned underground mines) the methods as set out in this section must be used.

Methane from extraction of coal

(2) One of the following methods must be used for estimating fugitive emissions of methane that result from the extraction of coal from the underground mine:

(a) subject to subsection (8), method 1 under section 3.5;

(b) method 4 under section 3.6.

Note There is no method 2 or 3 for subsection (2).

Carbon dioxide from extraction of coal

(3) If method 4 under section 3.6 is used under subsection (2), that method must be used for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from the underground mine.

Note There is no method 1, 2 or 3 for subsection (3).

Flaring

(4) For estimating emissions released from coal mine waste gas flared from the underground mine:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.14;

(ii) method 2 under section 3.15;

(iii) method 3 under section 3.16; and

(b) method 1 under section 3.14 must be used for estimating emissions of methane released;

(c) method 1 under section 3.14 must be used for estimating emissions of nitrous oxide released.

Note The flaring of coal mine waste gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 under section 3.14 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide, no method 2, 3 or 4 for emissions of methane and no method 2, 3 or 4 for emissions of nitrous oxide.

Venting or other fugitive release before extraction of coal

(5) Method 4 under Part 1.3 must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, that result from venting or other fugitive release of gas from the underground mine before coal is extracted from the mine.

Note There is no method 1, 2 or 3 for subsection (5).

Post-mining activities

(6) Method 1 under section 3.17 must be used for estimating fugitive emissions of methane that result from post-mining activities related to a gassy mine.

Note There is no method 2, 3 or 4 for subsection (6).

(7) However, for incidental emission source streams, another method may be used that is consistent with the principles in section 1.13.

(8) If coal mine waste gas from the mine is captured for combustion during the year, method 1 in subsection (2) must not be used.

Subdivision 3.2.2.2 Fugitive emissions from extraction of coal

3.5 Method 1 — extraction of coal

For paragraph 3.4 (2) (a), method 1 is:

$$E_j = Q \times EF_j$$

where:

E

E_j is the fugitive emissions of methane (***j***) that result from the extraction of coal from the mine during the year measured in CO_2-e tonnes.

Q is the quantity of run-of-mine coal extracted from the mine during the year measured in tonnes.

EF_j is the emission factor for methane (***j***), measured in CO_2-e tonnes per tonne of run-of-mine coal extracted from the mine, as follows:

(a) for a gassy mine — 0.305;

(b) for a non-gassy mine — 0.008.

3.6 Method 4 — extraction of coal

(1) For paragraph 3.4 (2) (b) and subsection 3.4 (3), method 4 is:

$$E_j = CO_{2\text{-}e_{j\text{ gen, total}}} - \gamma_j \left(Q_{ij,cap} + Q_{ij,flared} + Q_{ijtr}\right)$$

where:

E_j is the fugitive emissions of gas type (***j***) that result from the extraction of coal from the mine during the year, measured in CO_2-e tonnes.

$CO_2\text{-}e_{j\text{ gen, total}}$ is the total mass of gas type (***j***) generated from the mine during the year before capture and flaring is undertaken at the mine, measured in CO_2-e tonnes and estimated using the direct measurement of emissions in accordance with subsection (2).

γ_j is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, being:

(a) for methane — $6.784 \times 10^{-4} \times 21$; and

(b) for carbon dioxide — 1.861×10^{-3}.

$Q_{ij,cap}$ is the quantity of gas type (***j***) in coal mine waste gas type (***i***) captured for combustion from the mine and used during the year, measured in cubic metres and estimated in accordance with Division 2.3.6.

$Q_{ij,flared}$ is the quantity of gas type (***j***) in coal mine waste gas type (***i***) flared from the mine during the year, measured in cubic metres and estimated in accordance with Division 2.3.6.

Q_{ijtr} is the quantity of gas type (***j***) in coal mine waste gas type (***i***) transferred out of the mining activities during the year measured in cubic metres.

(2) The direct measurement of emissions released from the extraction of coal from an underground mine during a year by monitoring the gas stream at the underground mine may be undertaken by one of the following:

(a) continuous emissions monitoring (***CEM***) in accordance with Part 1.3;

(b) periodic emissions monitoring (***PEM***) in accordance with sections 3.7 to 3.12.

(3) For $\boldsymbol{Q_{ijtr}}$ in subsection (1), the quantity of gas type (***j***) must be estimated in accordance with Division 2.3.6 as if a reference in that Division to quantities of gaseous fuels combusted from the operation of a facility was a reference to quantities of gaseous fuels transferred out of the operation of a facility.

3.7 Estimation of emissions

(1) To obtain an estimate of the mass emissions rate of gas (***j***), being methane and carbon dioxide, at the time of measurement at the underground mine, the formula in subsection 1.21 (1) must be applied.

(2) The mass of emissions estimated under the formula must be converted into CO_2-e tonnes.

(3) The average mass emission rate for gas type (***j***) measured in CO_2–e tonnes per hour for a year must be calculated from the estimates obtained under subsections (1) and (2).

(4) The total mass of emissions of gas type (***j***) from the underground mine for the year is calculated by multiplying the average emissions rate obtained under subsection (3) by the number of hours during the year.

3.8 Overview — use of equipment

The following requirements apply to the use of PEM equipment:

(a) the requirements in section 3.9 about location of the sampling positions for the PEM equipment;

(b) the requirements in section 3.10 about measurement of volumetric flow rates in a gas stream;

(c) the requirements in section 3.11 about measurement of the concentrations of gas type (***j***) in the gas stream;

(d) the requirements in section 3.12 about representative data.

(e) the requirements in section 3.13 about performance characteristics of equipment.

3.9 Selection of sampling positions for PEM

For paragraph 3.8 (a), an appropriate standard or applicable State or Territory legislation must be complied with for the location of sampling positions for PEM equipment.

Note Appropriate standards include:

- AS 4323.1—1995/Amdt 1-1995, *Stationary source emissions — Selection of sampling positions*
- USEPA Method 1 — *Sample and velocity traverses for stationary sources (2000)*

3.10 Measurement of volumetric flow rates by PEM

For paragraph 3.8 (b), the measurement of the volumetric flow rates by PEM of the gas stream must be undertaken in accordance with an appropriate standard or applicable State or Territory legislation.

Note Appropriate standards include:

- ISO 14164:1999 *Stationary source emissions. Determination of the volume flowrate of gas streams in ducts - automated method*
- ISO 10780:1994 *Stationary source emissions. Measurement of velocity and volume flowrate of gas streams in ducts*
- USEPA Method 2 — *Determination of stack gas velocity and volumetric flow rate (Type S Pitot tube) (2000)*
- USEPA Method 2A — *Direct measurement of gas volume through pipes and small ducts (2000).*

3.11 Measurement of concentrations by PEM

For paragraph 3.8 (c), the measurement of the concentrations of gas type (***j***) in the gas stream by PEM must be undertaken in accordance with an appropriate standard or applicable State or Territory legislation.

Note Appropriate standards include USEPA — Method 3C — *Determination of carbon dioxide, methane, nitrogen and oxygen from stationary sources (1996).*

3.12 Representative data for PEM

(1) For paragraph 3.8 (d), sampling by PEM must be undertaken during the year for a sufficient duration to produce representative data that may be reliably extrapolated to provide estimates of emissions across the full range of operating conditions for that year.

(2) Emission estimates of PEM equipment must also be consistent with the principles in section 1.13.

3.13 Performance characteristics of equipment

For paragraph 3.8 (e), the performance characteristics of PEM equipment must be measured in accordance with section 1.34.

Subdivision 3.2.2.3 Emissions released from coal mine waste gas flared

3.14 Method 1 — coal mine waste gas flared

For subparagraph 3.4 (4) (a) (i) and paragraphs 3.4 (4) (b) and (c), method 1 is:

$$E_{(fl)ij} = \frac{Q_{i,flared} \times EC_i \times EF_{ij}}{1000} \times OF_{if}$$

where:

$E_{(fl)ij}$ is the emissions of gas type (***j***) released from coal mine waste gas (***i***) flared from the mine during the year, measured in CO_2-e tonnes.

$Q_{i,flared}$ is the quantity of coal mine waste gas (***i***) flared from the mine during the year, measured in cubic metres and estimated under Division 2.3.6.

EC_i is the energy content factor of coal mine waste gas (***i***) mentioned in item 19 of Schedule 1, measured in gigajoules per cubic metre.

EF_{ij} is the emission factor for gas type (***j***) and coal mine waste gas (***i***) mentioned in item 19 of Schedule 1, measured in CO_2-e tonnes per gigajoule.

OF_{if} is 0.98/0.995, which is the correction factor for the oxidation of coal mine waste gas (***i***) flared.

3.15 Method 2 — coal mine waste gas flared

(1) For subparagraph 3.4 (4) (a) (ii), method 2 is the same as method 1 under section 3.14.

(2) In applying method 1 under section 3.14, the facility specific emission factor (EF_{ij}) must be determined in accordance with the procedure for determining $EF_{i\,CO2ox,ec}$ in Division 2.3.3.

3.16 Method 3 — coal mine waste gas flared

(1) For subparagraph 3.4 (4) (a) (iii), method 3 is the same as method 1 under section 3.14.

(2) In applying method 1 under section 3.14, the facility specific emission factor EF_{ij} must be determined in accordance with the procedure for determining $EF_{i\,CO2ox,ec}$ in Division 2.3.4.

Subdivision 3.2.2.4 Fugitive emissions from post-mining activities

3.17 Method 1 — post-mining activities related to gassy mines

(1) For subsection 3.4 (6), method 1 is the same as method 1 under section 3.5.

(2) In applying method 1 under section 3.5, $\boldsymbol{EF_j}$ is taken to be 0.014, which is the emission factor for methane (***j***), measured in CO_2-e tonnes per tonne of run-of-mine coal extracted from the mine.

Division 3.2.3 Open cut mines

Subdivision 3.2.3.1 Preliminary

3.18 Application

This Division applies to UNFCCC Category 1.B.1.a.ii — fugitive emissions from open cut mining activities.

3.19 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by an open cut mine the methods as set out in this section must be used.

Methane from extraction of coal

(2) Subject to subsection (7), one of the following methods must be used for estimating fugitive emissions of methane that result from the extraction of coal from the mine:
  (a) method 1 under section 3.20;
  (b) method 2 under section 3.21;
  (c) method 3 under section 3.26.

Note There is no method 4 for subsection (2).

Carbon dioxide from extraction of coal

(3) If method 2 under section 3.21 is used under subsection (2), that method must be used for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from the open cut mine.

(4) If method 3 under section 3.26 is used under subsection (2), that method must be used for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from the open cut mine.

Note There is no method 1 or 4 for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from an open cut mine.

Flaring

(5) For estimating emissions released from coal mine waste gas flared from the open cut mine:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.27;

(ii) method 2 under section 3.28;

(iii) method 3 under section 3.29; and

(b) method 1 under section 3.27 must be used for estimating emissions of methane released; and

(c) method 1 under section 3.27 must be used for estimating emissions of nitrous oxide released.

Note The flaring of coal mine waste gas releases emissions of carbon dioxide, methane and nitrous oxide. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide, no method 2, 3 or 4 for emissions of methane and no method 2, 3 or 4 for emissions of nitrous oxide.

Venting or other fugitive release before extraction of coal

(6) Method 4 under Part 1.3 must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, that result from venting or other fugitive release of gas from the mine before coal is extracted from the mine.

Note There is no method 1, 2 or 3 for subsection (6).

(7) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.2.3.2 Fugitive emissions from extraction of coal

3.20 Method 1 — extraction of coal

For paragraph 3.19 (2) (a), method 1 is:

$$E_j = Q \times EF_j$$

where:

$\boldsymbol{E_j}$ is the fugitive emissions of methane (***j***) that result from the extraction of coal from the mine during the year measured in CO_2-e tonnes.

Q is the quantity of run-of-mine coal extracted from the mine during the year measured in tonnes.

EF_j is the emission factor for methane (***j***), measured in CO_2-e tonnes per tonne of run-of-mine coal extracted from the mine, taken to be the following:

(a) for a mine in New South Wales — 0.045;
(b) for a mine in Victoria — 0.0007;
(c) for a mine in Queensland — 0.017;
(d) for a mine in Western Australia — 0.017;
(e) for a mine in South Australia — 0.0007;
(f) for a mine in Tasmania — 0.014.

3.21 Method 2 — extraction of coal

(1) For paragraph 3.19 (2) (b) and subsection 3.19 (3), method 2 is:

$$E_j = \gamma_j \; \Sigma_z \left(S_{j,z} \right)$$

where:

E_j is the fugitive emissions of gas type (***j***) that result from the extraction of coal from the mine during the year, measured in CO_2-e tonnes.

γ_j is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, as follows:

(a) for methane — $6.784 \times 10^{-4} \times 21$;
(b) for carbon dioxide — 1.861×10^{-3}.

$\sum_z (S_{j,z})$ is the total of gas type (***j***) in all gas bearing strata (***z***) under the extraction area of the mine during the year, measured in cubic metres, where the gas in each strata is estimated under section 3.22.

(2) Method 2 requires each gas in a gas bearing strata to be sampled and analysed in accordance with the requirements in sections 3.24 and 3.25.

3.22 Total gas contained by gas bearing strata

(1) For method 2 under subsection 3.21 (1), ***$S_{j,z}$*** for gas type (***j***) contained in a gas bearing strata (***z***) under the extraction area of the mine during the year, measured in cubic metres, is:

$$S_{jz} = M_z \times \beta \times GC_{jz} - \Sigma_t Q_{ij,\,cap,z} - \Sigma_t Q_{ij,flared,z} - \Sigma_t Q_{ijtr} - \Sigma_t E_{j,vented,z}$$

where:

M_z is the mass of the gas bearing strata (***z***) under the extraction area of the mine during the year, measured in tonnes.

β is the proportion of the gas content of the gas bearing strata (z) that is released by extracting coal from the extraction area of the mine during the year, as follows:

(a) if the gas bearing strata is at or above the pit floor — 1;

(b) in any other case — as estimated under section 3.23.

GC_{jz} is the content of gas type (j) contained by the gas bearing strata (z) before gas capture, flaring or venting is undertaken at the extraction area of the mine during the year, measured in cubic metres per tonne of gas bearing strata at standard conditions.

$\sum Q_{ij,cap,z}$ is the total quantity of gas type (j) in coal mine waste gas (i) captured for combustion from the gas bearing strata (z) at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres.

$\sum Q_{ij,flared,z}$ is the total quantity of gas type (j) in coal mine waste gas (i) flared from the gas bearing strata (z) at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres.

$\sum Q_{ijtr}$ is the total quantity of gas type (j) in coal mine waste gas (i) transferred out of the mining activities at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres.

$\sum E_{j,vented,z}$ is the total emissions of gas type (j) vented from the gas bearing strata (z) at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres and estimated under subsection 3.19 (6).

(2) For $\sum Q_{ij,cap,z}$, $\sum Q_{ij,flared,z}$ and $\sum Q_{ijtr}$ in subsection (1), the quantity of gas type (j) must be estimated in accordance with Division 2.3.6 as if a reference in that Division to quantities of gaseous fuels combusted from the operation of a facility was a reference to the following:

(a) for $\sum Q_{ij,cap,z}$ — quantities of gaseous fuels captured from the operation of a facility;

(b) for $\sum_t Q_{ij,flared,z}$ — quantities of gaseous fuels flared from the operation of a facility;

(c) for $\sum Q_{ijtr}$ — quantities of gaseous fuels transferred out of the operation of a facility.

3.23 Estimate of proportion of gas content released below pit floor

For paragraph (b) of the factor β in subsection 3.22 (1):

$$\beta = 1 - \frac{x - h}{dh}$$

where:

x is the depth in metres of the floor of the gas bearing strata (*z*) measured from ground level.

h is the depth in metres of the pit floor of the mine measured from ground level.

dh is 20, being representative of the depth in metres of the gas bearing strata below the pit floor that releases gas.

3.24 General requirements for sampling

(1) Core samples of a gas bearing strata must be collected to produce estimates of gas content that are representative of the gas bearing strata in the extraction area of the mine during the year.

(2) The sampling process must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(3) Bias must be tested in accordance with an appropriate standard (if any).

(4) The value obtained from the samples must only be used for the open cut mine from which it was intended to be representative.

3.25 General requirements for analysis of gas and gas bearing strata

Analysis of a gas and a gas bearing strata, including the mass and gas content of the strata, must be done in accordance with an appropriate standard.

Note 1 An appropriate standard for analysis of a gas includes AS 3980—1999 *Guide to the determination of gas content of coal—Direct desorption method*.

Note 2 An appropriate standard for analysis of a gas bearing strata includes AS 2519—1993 *Guide to the technical evaluation of higher rank coal deposits*.

3.26 Method 3 — extraction of coal

(1) For paragraph 3.19 (2) (c) and subsection 3.19 (4), method 3 is the same as method 2 under section 3.21

(2) In applying method 2 under section 3.21 a sample of gas bearing strata must be collected in accordance with an appropriate standard, including:

(a) AS 2617—1996 *Sampling from coal seams* or an equivalent standard; and

(b) AS 2519—1993 *Guide to the technical evaluation of higher rank coal deposits* or an equivalent standard.

Subdivision 3.2.3.3 Emissions released from coal mine waste gas flared

3.27 Method 1 — coal mine waste gas flared

(1) For subparagraph 3.19 (5) (a) (i) and paragraph 3.19 (5) (b) and paragraph (5) (c), method 1 is the same as method 1 under section 3.14.

(2) In applying method 1 under section 3.14, a reference to an underground mine is taken to be a reference to an open cut mine.

3.28 Method 2 — coal mine waste gas flared

For subparagraph 3.19 (5) (a) (ii), method 2 is the same as method 2 under section 3.15.

3.29 Method 3 — coal mine waste gas flared

For subparagraph 3.19 (5) (a) (iii), method 3 is the same as method 3 under section 3.16.

Division 3.2.4 Decommissioned underground mines

Subdivision 3.2.4.1 Preliminary

3.30 Application

This Division applies to UNFCCC Category 1.B.1.c — fugitive emissions from decommissioned underground mines that have been closed for a continuous period of at least 1 year but less than 20 years.

3.31 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by a decommissioned underground mine that has been closed for a continuous period of at least 1 year but less than 20 years the methods as set out in this section must be used.

Methane from decommissioned mines

(2) One of the following methods must be used for estimating fugitive emissions of methane that result from the mine:

(a) subject to subsection (6), method 1 under section 3.32;

(b) method 4 under section 3.37.

Note There is no method 2 or 3 for subsection (2).

Carbon dioxide from decommissioned mines

(3) If method 4 under section 3.37 is used under subsection (2), that method must be used for estimating fugitive emissions of carbon dioxide that result from the mine.

Note There is no method 1, 2 or 3 for subsection (3).

Flaring

(4) For estimating emissions released from coal mine waste gas flared from the mine:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.38;

(ii) method 2 under section 3.39;

(iii) method 3 under section 3.40; and

(b) method 1 under section 3.38 must be used for estimating emissions of methane released.

(c) method 1 under section 3.38 must be used for estimating emissions of nitrous oxide released.

Note The flaring of coal mine waste gas releases emissions of carbon dioxide, methane and nitrous oxide. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide, no method 2, 3 or 4 for emissions of methane and no method 2, 3 or 4 for nitrous oxide.

(5) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

(6) If coal mine waste gas from the decommissioned underground mine is captured for combustion during the year, method 1 in subsection (2) must not be used.

Subdivision 3.2.4.2 Fugitive emissions from decommissioned underground mines

3.32 Method 1 — decommissioned underground mines

(1) For paragraph 3.31 (2) (a), method 1 is:

$$E_{dm} = [E_{tdm} \times EF_{dm} \times (1 - F_{dm})]$$

where:

***E*$_{dm}$** is the fugitive emissions of methane from the mine during the year measured in CO_2-e tonnes.

E_{tdm} is the emissions from the mine for the last full year that the mine was in operation measured in CO_2-e tonnes and estimated under section 3.5 or 3.6.

EF_{dm} is the emission factor for the mine calculated under section 3.33.

F_{dm} is the fraction of the mine flooded during the year, as estimated under section 3.34.

(2) However, if, under subsection (1), the estimated emissions in CO_2-e tonnes for the mine during the year is less than $0.02 \times E_{tdm}$, the estimated emissions for the mine during the year is taken to be $0.02 \times E_{tdm}$.

3.33 Emission factor for decommissioned underground mines

For section 3.32, EF_{dm} is the integral under the curve of:

$$(1 + A \times T)^b - C$$

for the period between T and T-1,
where:

A is:
(a) for a gassy mine — 0.23; or
(b) for a non-gassy mine — 0.35.

T is the number of years since the mine was decommissioned.

b is:
(a) for a gassy mine — -1.45; or
(b) for a non-gassy mine — -1.01.

C is:
(a) for a gassy mine — 0.024; or
(b) for a non-gassy mine — 0.088.

3.34 Measurement of proportion of mine that is flooded

For section 3.32, F_{dm} is:

$$\frac{M_{WI}}{M_{VV}}$$

where:

M_{WI} is the rate of water flow into the mine in cubic metres per year as measured under section 3.35.

M_{VV} is the mine void volume in cubic metres as measured under section 3.36.

3.35 Water flow into mine

For M_{WI} in section 3.34, the rate of water flow into the mine must be measured by:

(a) using water flow rates for the mine estimated in accordance with an appropriate standard; or

(b) using the following average water flow rates:

  (i) for a mine in the southern coalfield of New South Wales — 913 000 cubic metres per year; or

  (ii) for a mine in the Newcastle, Hunter, Western or Gunnedah coalfields in New South Wales — 450 000 cubic metres per year; or

  (iii) for a mine in Queensland — 74 000 cubic metres per year.

Note An appropriate standard includes AS 2519—1993 *Guide to the technical evaluation of higher rank coal deposits*.

3.36 Size of mine void volume

For M_{VV} in section 3.34, the size of the mine void volume must be measured by:

(a) using mine void volumes for the mine estimated in accordance with industry practice; or

(b) dividing the total amount of run-of-mine coal extracted from the mine before the mine was decommissioned by 1.425.

3.37 Method 4 — decommissioned underground mines

(1) For paragraph 3.31 (2) (b) and subsection 3.31 (3), method 4 is the same as method 4 in section 3.6.

(2) In applying method 4 under section 3.6, a reference to an underground mine is taken to be a reference to a decommissioned underground mine.

Subdivision 3.2.4.3 Fugitive emissions from coal mine waste gas flared

3.38 Method 1 — coal mine waste gas flared

(1) For subparagraph 3.31 (4) (a) (i) and paragraphs 3.31 (4) (b) and (4) (c), method 1 is the same as method 1 under section 3.14.

(2) In applying method 1 under section 3.14, a reference to an underground mine is taken to be a reference to a decommissioned underground mine.

3.39 Method 2 — coal mine waste gas flared

For subparagraph 3.31 (4) (a) (ii), method 2 is the same as method 2 under section 3.15.

3.40 Method 3 — coal mine waste gas flared

For subparagraph 3.31 (4) (a) (iii), method 3 is the same as method 3 under section 3.16.

Part 3.3 Oil and natural gas — fugitive emissions

Division 3.3.1 Preliminary

3.41 Outline of Part

This Part provides for UNFCCC Category 1.B.2 — fugitive emissions as follows:

(a) UNFCCC Category 1.B.2.a.i — oil exploration (see Division 3.3.2);

(b) UNFCCC Category 1.B.2.b.i — gas exploration (see Division 3.3.2);

(c) UNFCCC Category 1.B.2.a.ii — crude oil production (see Division 3.3.3);

(d) UNFCCC Category 1.B.2.a.iii — crude oil transport (see Division 3.3.4);

(e) UNFCCC Category 1.B.2.a.iv — crude oil refining (see Division 3.3.5);

(f) UNFCCC Category 1.B.2.b.ii — natural gas production and processing other than emissions that are vented or flared (see Division 3.3.6);

(g) UNFCCC Category 1.B.2.b.iii — natural gas transmission (see Division 3.3.7);

(h) UNFCCC Category 1.B.2.b.iv — natural gas distribution (see Division 3.3.8);

(i) UNFCCC Category 1.B.2.c. — natural gas production and processing (emissions that are vented or flared) (see Division 3.3.9).

Division 3.3.2 Oil and gas exploration

3.42 Application

This Division applies to fugitive emissions from oil and gas exploration, UNFCCC Category 1.B.2a.i (oil) and UNFCCC Category 1.B.2.b.i (gas).

3.43 Available methods

(1) Subject to section 1.18, for estimating emissions released by oil or gas flaring during a year from the operation of a facility that is constituted by crude oil production:

(a) if estimating emissions of carbon dioxide released — one of the following methods must be used:

(i) method 1 under section 3.44;

(ii) method 2 under section 3.45;

(iii) method 3 under section 3.46; and

(b) if estimating emissions of methane released — one of the following methods must be used:

(i) method 1 under section 3.44;

(ii) method 2 under section 3.45; and

(c) if estimating emissions of nitrous oxide released — method 1 under section 3.44 must be used.

Note There is no method 4 under paragraph (a), no methods 3 or 4 under paragraph (b) and no methods 2, 3 or 4 under paragraph (c).

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

3.44 Method 1 — oil and gas exploration

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the fugitive emissions of gas type (***j***) from a fuel type (***i***) flared in the oil and gas exploration during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) flared in the oil and gas exploration during the year measured in tonnes.

EF_{ij} is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of the fuel type (***i***) flared.

(2) For ***EF_{ij}*** in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor, for gas type (***j***), for each fuel type (***i***) specified in column 2 of that item.

Item	**Fuel type (*i*)**	**Emission factor for gas type (*j*) (tonnes CO_2-e/tonnes of fuel flared)**		
		CO_2	**CH_4**	**N_2O**
1	Unprocessed gas flared	2.8	0.7	0.03
2	Crude oil	3.2	0.007	0.07

3.45 Method 2 — oil and gas exploration

(1) Method 2 is the same as method 1 but the carbon dioxide emission factor ***EF_{ij}*** must be determined in accordance with:

(a) for the combustion of gaseous fuels — method 2 specified in Division 2.3.3;

(b) for the combustion of liquid fuels — method 2 specified in Division 2.4.3.

(2) The methane emission factor must be determined with section 4.4 of the API Compendium.

3.46 Method 3 — oil and gas exploration

Method 3 is the same as method 1 but the carbon dioxide emission factor EF_{ij} must be determined in accordance with:

(a) for the combustion of gaseous fuels — method 3 specified in Division 2.3.4;

(b) for the combustion of liquid fuels — method 3 specified in Division 2.4.4.

Division 3.3.3 Crude oil production

Subdivision 3.3.3.1 Preliminary

3.47 Application

This Division applies to UNFCCC Category 1.B.2.a.ii — fugitive emissions from crude oil production.

Subdivision 3.3.3.2 Crude oil production (non-flared) — fugitive emissions of methane

3.48 Available methods

(1) Subject to section 1.18, for estimating fugitive emissions of methane, other than from oil or gas flaring, during a year from the operation of a facility that is constituted by crude oil production, one of the following methods must be used:

(a) method 1 under section 3.49;

(b) method 2 under section 3.50;

Note There is no method 3 or 4 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

3.49 Method 1 — crude oil production (non-flared) emissions of methane

(1) Method 1 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)\ ij}$$

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil production during the year measured in CO_2-e tonnes.

Σ_k is the emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from all of the equipment of type (***k***) specified in column 2 of the table in subsection (2), if the equipment is used in the crude oil production.

Q_{ik} is the total of the quantities of crude oil measured in tonnes that pass through each equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the crude oil production.

EF_{ijk} is the emission factor for methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the crude oil production.

Q_i is the total quantity of crude oil (***i***) measured in tonnes that passes through the crude oil production.

$EF_{(l)\ ij}$ is 1.2 x 10^{-3}, which is the emission factor for methane (***j***) from general leaks in the crude oil production, measured in CO_2-e tonnes per tonne of crude oil that passes through the crude oil production.

(2) For EF_{ijk} mentioned in subsection (1), column 3 of an item in the following table specifies the emission factor for an equipment of type (***k***) specified in column 2 of that item:

Item	**Equipment type (*k*)**	**Emission factor for gas type (*j*) (tonnes CO_2-e/tonnes fuel throughput)**
		CH_4
1	Internal floating tank	8.4×10^{-7}
2	Fixed roof tank	4.2×10^{-6}
3	Floating tank	3.2×10^{-6}

3.50 Method 2 — crude oil production (non-flared) emissions of methane

(1) Method 2 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil production during the year measured in CO_2-e tonnes.

Σ_k is the emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment type is used in the crude oil production.

Q_{ik} is the total of the quantities of crude oil that pass through each equipment type (***k***), or the number of equipment units of type (***k***), listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production, measured in tonnes.

EF_{ijk} is the emission factor of methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production.

(2) For EF_{ijk}, the emission factors for methane (***j***), as crude oil passes through an equipment type (***k***), are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type — those factors.

Subdivision 3.3.3.3 Crude oil production (flared) — fugitive emissions of carbon dioxide, methane and nitrous oxide

3.51 Available methods

(1) Subject to section 1.18, for estimating emissions released by oil or gas flaring during a year from the operation of a facility that is constituted by crude oil production:

(a) if estimating emissions of carbon dioxide released — one of the following methods must be used:

(i) method 1 under section 3.52;

(ii) method 2 under section 3.53;

(iii) method 3 under section 3.54; and

(b) if estimating emissions of methane released — one of the following methods must be used:
  (i) method 1 under section 3.55;
  (ii) method 2 under section 3.56; and

(c) if estimating emissions of nitrous oxide released — method 1 under section 3.55 must be used.

Note There is no method 4 under paragraph (a), no methods 3 or 4 under paragraph (b) and no methods 2, 3 or 4 under paragraph (c).

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

3.52 Method 1 — crude oil production (flared) emissions

(1) For subparagraph 3.51 (a) (i), method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions of gas type (***j***) measured in CO_2-e tonnes from a fuel type (***i***) flared in crude oil production during the year.

Q_i is the quantity of fuel type (***i***) measured in tonnes flared in crude oil production during the year.

EF_{ij} is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of the fuel type (***i***) flared.

(2) For EF_{ij} mentioned in subsection (1), columns 3, 4 and 5 of an item in following table specify the emission factor for each fuel type (***i***) specified in column 2 of that item.

Item	**Fuel type *(i)***	**Emission factor for gas type (*j*) (tonnes CO_2-e/tonnes of fuel flared)**		
		CO_2	**CH_4**	**N_2O**
1	Unprocessed gas flared	2.8	0.7	0.03
2	Crude oil	3.2	0.007	0.07

3.53 Method 2 — crude oil production (flared) emissions of carbon dioxide

For subparagraph 3.51 (a) (ii), method 2 is the same as method 1 but the emission factor EF_{ij} must be determined in accordance with:

(a) for the combustion of gaseous fuels — method 2 specified in Division 2.3.3; and

(b) for the combustion of liquid fuels — method 2 specified in Division 2.4.3.

3.54 Method 3 — crude oil production (flared) emissions of carbon dioxide

For subparagraph 3.51 (a) (iii), method 3 is the same as method 1 but the emission factor EF_{ij} must be determined in accordance with:

(a) for the combustion of gaseous fuels — method 3 specified in Division 2.3.4; and

(b) for the combustion of liquid fuels — method 3 specified in Division 2.4.4.

3.55 Method 1 — crude oil production (flared) emissions of methane and nitrous oxide

For subparagraph 3.51 (b) (i) and paragraph 3.51 (c), method 1 is as provided for section 3.52.

3.56 Method 2 — crude oil production (flared) emissions of methane and nitrous oxide

For subparagraph 3.51 (b) (ii), method 2 is the same as method 1 in section 3.55, but the emission factor EF_{ij} must be determined in accordance with section 4.4 of the API Compendium.

Division 3.3.4 Crude oil transport

3.57 Application

This Division applies to UNFCCC category 1.B.2.a.iii. — fugitive emissions from crude oil transport.

3.58 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating fugitive emissions of methane released during a year from the operation of a facility that is constituted by crude oil transport:

(a) method 1 under section 3.59;

(b) method 2 under section 3.60.

Note There is no method 3 or 4 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

3.59 Method 1 — crude oil transport

Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from the crude oil transport during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of crude oil (***i***) measured in tonnes and transported during the year.

$\boldsymbol{EF_{ij}}$ is the emission factor for methane (***j***), which is 7.3×10^{-4} tonnes CO_2-e per tonnes of crude oil transported during the year.

3.60 Method 2 — fugitive emissions from crude oil transport

(1) Method 2 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from the crude oil transport during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport .

$\boldsymbol{Q}_{ik}$ is the total of the quantities of crude oil measured in tonnes that pass through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport.

$\boldsymbol{EF_{ijk}}$ is the emission factor of methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes though each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport.

(2) For $\boldsymbol{EF_{ijk}}$**,** the emission factors for methane (***j***), as crude oil passes through equipment type (***k***), are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type — those factors.

Division 3.3.5 Crude oil refining

3.61 Application

This Division applies to UNFCCC Category 1.B.2.a.iv — fugitive emissions from crude oil refining.

3.62 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by crude oil refining the methods as set out in this section must be used.

Crude oil refining and storage tanks

(2) One of the following methods must be used for estimating fugitive emissions of methane that result from crude oil refining and from storage tanks for crude oil:

(a) method 1 under section 3.63;

(b) method 2 under section 3.64.

Note There is no method 3 or 4 for subsection (2).

Process vents, system upsets and accidents

(3) One of the following methods must be used for estimating fugitive emissions of each type of gas, being carbon dioxide, methane and nitrous oxide, that result from deliberate releases from process vents, system upsets and accidents:

(a) method 1 under section 3.65;

(b) method 4 under section 3.66.

Note There is no method 2 or 3 for subsection (3).

Flaring

(4) For estimating emissions released from gas flared from crude oil refining:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

  (i) method 1 under section 3.67;

  (ii) method 2 under section 3.68;

  (iii) method 3 under section 3.69; and

(b) one of the following methods must be used for estimating emissions of methane released:

  (i) method 1 under section 3.67;

  (ii) method 2 under section 3.68; and

(c) method 1 under section 3.67 must be used for estimating emissions of nitrous oxide released.

Note The flaring of gas from crude oil refining releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 under section 3.67 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide, no method 3 or 4 for emissions of methane and no method 2, 3 or 4 for emissions of nitrous oxide.

(5) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.3.5.1 Fugitive emissions from crude oil refining and from storage tanks for crude oil

3.63 Method 1 — crude oil refining and storage tanks for crude oil

Method 1 is:

$$E_{ij} = \Sigma_i\ Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from fuel type (***i***) being crude oil refined or stored in tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\sum_I}$ is the sum of emissions of methane (***j***) released during refining and from storage tanks during the year.

$\boldsymbol{Q}_i$ is the quantity of crude oil (***i***) refined or stored in tanks during the year measured in tonnes.

$\boldsymbol{EF_{ij}}$ is the emission factor for methane (***j***) being 7.1 x 10^{-4} tonnes CO_2-e per tonne of crude oil refined and 1.3 x 10^{-4} tonnes CO_2-e per tonne of crude oil stored in tanks.

3.64 Method 2 — crude oil refining and storage tanks for crude oil

(1) Method 2 is:

$$E_{ij} = \Sigma_k\ (Q_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from the crude oil refining and from storage tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the emissions of methane (***j***) measured in tonnes of CO_2-e estimated by summing up the emissions released from each equipment types (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

Q_{ik} is the total of the quantities of crude oil measured in tonnes that pass through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

EF_{ijk} is the emission factor for methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes though each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

(2) For ***EF_{ijk}***, the emission factors for methane (***j***) as the crude oil passes through an equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type — those factors.

Subdivision 3.3.5.2 Fugitive emissions from deliberate releases from process vents, system upsets and accidents

3.65 Method 1 — fugitive emissions from deliberate releases from process vents, system upsets and accidents

Method 1 is:

$$E_i = Q_i \times CCF_i \times 3.664$$

where:

E_i is the fugitive emissions during the year from deliberate releases from process vents, system upsets and accidents in the crude oil refining measured in CO_2-e tonnes.

Q_i is the quantity of refinery coke (***i***) burnt to restore the activity of the catalyst of the crude oil refinery (and not used for energy) during the year measured in tonnes.

CCF_i is the carbon content factor for refinery coke (***i***) as mentioned in Schedule 3.

3.664 is the conversion factor to convert an amount of carbon in tonnes to an amount of carbon dioxide in tonnes.

3.66 Method 4 — deliberate releases from process vents, system upsets and accidents

(1) Method 4 is:

(a) is as set out in Part 1.3; or

(b) uses the process calculation approach in section 5.2 of the API Compendium.

(2) For paragraph (1) (b), all carbon monoxide is taken to fully oxidise to carbon dioxide and must be included in the calculation.

Subdivision 3.3.5.3 Fugitive emissions released from gas flared from the oil refinery

3.67 Method 1 — gas flared from crude oil refining

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of gas type (***j***) released from the gas flared in the crude oil refining during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of gas type (***i***) flared during the year measured in tonnes.

$\boldsymbol{EF_{ij}}$ is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of gas type (***i***) flared in the crude oil refining during the year.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for gas type (***j***) for the fuel type (***i***) specified in column 2 of that item:

Item	**fuel type (*i*)**	**Emission factor of gas type (*j*) (tonnes CO_2-e/tonnes fuel flared)**		
		CO_2	**CH_4**	**N_2O**
1	gas	2.7	0.1	0.03

3.68 Method 2 — gas flared from crude oil refining

(1) Method 2 is the same as method 1 under section 3.67 but the carbon dioxide emission factor $\boldsymbol{EF_{ij}}$ must be determined in accordance with method 2 for the consumption of gaseous fuels as specified in Division 2.3.3.

(2) The methane emission factor must be determined with section 4.4 of the API Compendium.

3.69 Method 3 — gas flared from crude oil refining

Method 3 is the same as method 1 under section 3.67 but the emission factor $\boldsymbol{EF_{ij}}$ must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

Division 3.3.6 Natural gas production and processing (other than emissions that are vented or flared)

3.70 Application

This Division applies to UNFCCC category 1.B.2.b.ii — natural gas production and processing (other than emissions that are vented or flared).

3.71 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating fugitive emissions of methane (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas production and processing:

(a) method 1 under section 3.72;

(b) method 2 under section 3.73.

Note There is no method 3 or 4 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

3.72 Method 1 — natural gas production and processing (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \Sigma_k \ (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)\,ij}$$

where:

E

E_{ij} is the fugitive emissions of methane (***j***) (other than emissions that are vented or flared) from the natural gas production and processing during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane (***j***), measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in the natural gas production and processing.

Q_{ik} is the total of the quantities of natural gas that pass through each equipment type (***k***), or the number of equipment units of type (***k***) specified in column 2 of the table in subsection (2), measured in tonnes.

EF_{ijk} is the emission factor for methane (***j***) measured in CO_2-e tonnes per tonne of natural gas that passes through each equipment type (***k***) during the year if the equipment is used in the natural gas production and processing.

Q_i is the total quantity of natural gas (*i*) that passes through the natural gas production and processing measured in tonnes.

$EF_{(l)\,ij}$ is 1.2×10^{-3}, which is the emission factor for methane (*j*) from general leaks in the natural gas production and processing, measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas production and processing.

(2) For EF_{ijk} in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (*j*) for an equipment type (*k*) specified in column 2 of that item:

Item	Equipment type (*k*)	Emission factor for methane (*j*) (tonnes CO_2-e/tonnes fuel throughput)
1	Internal floating tank	8.4×10^{-7}
2	Fixed roof tank	4.2×10^{-6}
3	Floating tank	3.2×10^{-6}

3.73 Method 2— natural gas production and processing (other than venting and flaring)

(1) Method 2 is:

$$E_{ij} = \Sigma_k \left(Q_{ik} \times EF_{ijk}\right)$$

where:

E_{ij} is the fugitive emissions of methane (*j*) from the natural gas production and processing during the year measured in CO_2-e tonnes.

Σ_k is the emissions of methane (*j*) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (*k*) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas production and processing.

Q_{ik} is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (*k*) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas production and processing.

EF_{ijk} is the emission factor of methane (*j*) measured in tonnes of CO_2-e per tonne of natural gas that passes through each equipment type (*k*) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas production and processing.

(2) For EF_{ijk}, the emission factors for methane (*j*) as the natural gas passes through the equipment types (*k*) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type — those factors.

Division 3.3.7 Natural gas transmission

3.74 Application

This Division applies to UNFCCC category 1.B.2.b.iii — natural gas transmission.

3.75 Available methods

(1) Subject to section 1.18 and subsection (2), one of the following methods must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, released from the operation of a facility that is constituted by natural gas transmission through a system of pipelines during a year:

(a) method 1 under section 3.76;

(b) method 2 under section 3.77.

Note There is no method 3 or 4 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

3.76 Method 1 — natural gas transmission

Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the fugitive emissions of gas type (***j***) from natural gas transmission through a system of pipelines of length (***i***) during the year measured in CO_2-e tonnes.

Q_i is the length of the system of pipelines (***i***) measured in kilometres.

EF_{ij} is the emission factor for gas type (***j***), which is 0.02 for carbon dioxide and 8.7 for methane, measured in tonnes of CO_2-e emissions per kilometre of pipeline (***i***).

3.77 Method 2 — natural gas transmission

(1) Method 2 is:

$$E_j = \Sigma_k \ (Q_k \times EF_{jk})$$

where:

E_j is the fugitive emissions of gas type (***j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.

Σ_k is the total of emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission.

Q_k is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (***k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission.

EF_{jk} is the emission factor of gas type (***j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, where the equipment is used in the natural gas transmission.

(2) For EF_{jk}, the emission factors for a gas type (***j***) as the natural gas passes through the equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's sections 5 and 6.1.2, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material estimated in accordance with the results of published research for the crude oil industry and the principles of section 1.13; or

(d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type — those factors.

Division 3.3.8 Natural gas distribution

3.78 Application

This Division applies to UNFCCC Category 1.B.2.b.iv — natural gas distribution.

3.79 Available methods

(1) Subject to section 1.18 and subsection (2), one of the following methods must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, released during a year from the operation of a facility that is constituted by natural gas distribution through a system of pipelines:

(a) method 1 under section 3.80;

(b) method 2 under section 3.81.

Note There is no method 3 or 4 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

3.80 Method 1 — natural gas distribution

(1) Method 1 is:

$$E_{ij} = S_p \times \%UAG_p \times 0.55 \times C_{i,p,j}$$

where:

E_{ij} is the fugitive emissions of gas type (***j***) that result from natural gas distribution through a system of pipelines with sales of gas (***S_p***) during the year, measured in CO_2-e tonnes.

S_p is the total gas sales during the year from the pipeline system measured in terajoules.

$\%UAG_p$ is the percentage of unaccounted for gas in the pipeline system in a State or Territory, relative to the amount of gas issued annually by gas utilities in that State or Territory.

Note The value 0.55 following the variable ***$\%UAG_p$*** in method 1 represents the proportion of gas that is unaccounted for and released as emissions.

$C_{i,p,j}$ is the natural gas composition factor for gas type (***j***) for the natural gas supplied from the pipeline system in a State or Territory measured in CO_2-e tonnes per terajoule.

(2) For ***$\%UAG_p$*** in subsection (1), column 3 of an item in the following table specifies the percentage of unaccounted for gas in the pipeline system in a State or Territory specified in column 2 of that item.

(3) For ***$C_{i,p,j}$*** in subsection (1), columns 4 and 5 of an item in the following table specify the natural gas composition factor for carbon dioxide and methane for a pipeline system in a State or Territory specified in column 2.

Item	**State**	**Unaccounted for gas (a)%**	**Natural gas composition factor (a)(tonnes CO_2-e/TJ)**	
		UAG_p	**CO_2**	**CH_4**
1	NSW and ACT	2.40	0.8	328
2	VIC	2.75	0.9	326
3	QLD	2.63	0.8	317
4	WA	2.55	1.1	306
5	SA	4.00	0.8	328

Item	State	Unaccounted for gas (a)%	Natural gas composition factor (a)(tonnes CO_2-e/TJ)	
		UAG_p	CO_2	CH_4
6	TAS	0.40	0.9	326
7	NT	0.10	0.0	264

3.81 Method 2 — natural gas distribution

(1) Method 2 is:

$$E_j = \Sigma_k \ (Q_k \times EF_{jk})$$

where:

E_j is the fugitive emissions of gas type (***j***) that result from the natural gas distribution during the year measured in CO_2-e tonnes.

Σ_k is the total of emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

Q_k is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (***k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

EF_{jk} is the emission factor for gas type (***j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

(2) For EF_{jk}, the emission factors for gas type (***j***) as the natural gas passes through the equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium; or

(b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Sections 5 and 6.1.2, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material estimated in accordance with the results of published research for the crude oil industry and the principles of section 1.13; or

(d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type — those factors.

Division 3.3.9 Natural gas production and processing (emissions that are vented or flared)

3.82 Application

This Division applies to UNFCCC Category 1.B.2.c — natural gas production and processing (emissions that are vented or flared).

3.83 Available methods

(1) Subject to section 1.18, for estimating emissions (emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas production and processing the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions of methane that result from deliberate releases from process vents, system upsets and accidents:

  (i) method 1 under section 3.84; and
  (ii) method 4 under Part 1.3.

Note There is no method 2 or 3 for subsection (2).

(3) For estimating emissions released from gas flared from natural gas production and processing:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:
  (i) method 1 under section 3.85;
  (ii) method 2 under section 3.86;
  (iii) method 3 under section 3.87; and

(b) one of the following methods must be used for estimating emissions of methane released:
  (i) method 1 under section 3.85;
  (ii) method 2 under section 3.86; and

(c) method 1 under section 3.85 must be used for estimating emissions of nitrous oxide released.

Note The flaring of gas from natural gas production and processing releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.85 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide, no method 3 or 4 for emissions of methane and no method 2, 3 or 4 for emissions of nitrous oxide.

(4) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.3.9.1 Fugitive emissions that result from deliberate releases from process vents, system upsets and accidents

3.84 Method 1 — deliberate releases from process vents, system upsets and accidents

Method 1 is as described in section 5 of the API Compendium.

Subdivision 3.3.9.2 Emissions released from gas flared from natural gas production and processing

3.85 Method 1 — gas flared from natural gas production and processing

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions of gas type (***j***) measured in CO_2-e tonnes that result from a fuel type (***i***) flared in the natural gas production and processing during the year.

Q_i is the quantity measured in tonnes of gas flared during the year.

EF_{ij} is the emission factor for gas type (***j***) measured in CO_2-e tonnes of emissions per tonne of gas flared (***i***) in the natural gas production and processing during the year.

(2) For EF_{ij} mentioned in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for fuel type (***i***) specified in column 2 of that item.

Item	fuel type (*i*)	Emission factor of gas type (*j*) (tonnes CO_2-e/tonnes fuel flared)		
		CO_2	CH_4	N_2O
1	gas	2.7	0.1	0.03

3.86 Method 2 — gas flared from natural gas production and processing

(1) Method 2 is the same as method 1 but the carbon dioxide emission factor (EF_{ij}) must be determined in accordance with method 2 for the consumption of gaseous fuels as specified in Division 2.3.3.

(2) The methane emission factor must be determined with section 4.4 of the API Compendium.

3.87 Method 3 — gas flared from natural gas production and processing

Method 3 is the same as method 1 but the emission factor ($\boldsymbol{EF_{ij}}$) must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

Chapter 4 Industrial processes emissions (UNFCCC Category 2)

Part 4.1 Preliminary

4.1 Outline of Chapter

(1) This Chapter provides for UNFCCC Category 2 — industrial processes emissions that are released by industries mentioned in subsection (2) that need for their operation:

- (a) the calcination of carbonates; or
- (b) the use of fuels as:
  - (i) feedstock; or
  - (ii) carbon reductants.

(2) For subsection (1), the industries are as follows:

- (a) in Part 4.2 — mineral industries:
  - (i) producing cement clinker (Division 4.2.1); or
  - (ii) producing lime (Division 4.2.2); or
  - (iii) other than an industry mentioned in subparagraph (i) or (ii) which involve the calcination of carbonates (Division 4.2.3); or
  - (iv) using and producing soda ash (Division 4.2.4);
- (b) in Part 4.3 — chemical industries producing:
  - (i) ammonia (Division 4.3.1); or
  - (ii) nitric acid (Division 4.3.2); or
  - (iii) adipic acid (Division 4.3.3); or
  - (iv) carbide (Division 4.3.4); or
  - (v) titanium dioxide (Division 4.3.5); or
  - (vi) synthetic rutile (Division 4.3.6);
- (c) in Part 4.4 — metal industries producing:
  - (i) iron and steel (Division 4.4.1); or
  - (ii) ferroalloy metal (Division 4.4.2); or
  - (iii) aluminium (Divisions 4.4.3 and 4.4.4); or
  - (iv) other metals (Division 4.4.5);

(3) This Chapter, in Part 4.5, also applies to emissions released from the consumption of the following synthetic gases:

(a) hydrofluorocarbons;

(b) sulphur hexafluoride.

Part 4.2 Industrial processes — mineral products

Division 4.2.1 Cement clinker production

4.2 Application

This Division applies to UNFCCC Category 2.A.1 — cement clinker production.

4.3 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of cement clinker:

(a) method 1 under section 4.4;
(b) method 2 under section 4.5;
(c) method 3 under section 4.8;
(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams, another method may be used that is consistent with the principles in section 1.13.

4.4 Method 1 — cement clinker production

Method 1 is:

$$E_{ij} = \left(EF_{ij} + EF_{toc,j}\right) \times \left(A_i + A_{ckd} \times F_{ckd}\right)$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from the production of cement clinker (***i***) during the year measured in CO_2-e tonnes.

EF_{ij} is 0.534, which is the carbon dioxide (***j***) emission factor for cement clinker (***i***), measured in tonnes of emissions of carbon dioxide per tonne of cement clinker produced.

$EF_{toc,j}$ is 0.010, which is the carbon dioxide (***j***) emission factor for carbon-bearing non-fuel raw material, measured in tonnes of emissions of carbon dioxide per tonne of cement clinker produced.

A_i is the quantity of cement clinker (***i***) produced during the year measured in tonnes and estimated under Division 4.2.5.

A_{ckd} is the quantity of cement kiln dust produced as a result of the production of cement clinker during the year, measured in tonnes and estimated under Division 4.2.5.

F_{ckd} is:

(a) the degree of calcination of cement kiln dust produced as a result of the production of cement clinker during the year, expressed as a decimal fraction; or

(b) if the information mentioned in paragraph (a) is not available — the value 1.

4.5 Method 2 — cement clinker production

(1) Subject to this section, method 2 is the same as method 1 under section 4.4.

(2) In applying method 1 under section 4.4, EF_{ij} is taken to be:

$$F_{CaO} \times 0.785 + F_{MgO} \times 1.092$$

where:

F_{CaO} is the estimated fraction of cement clinker that is calcium oxide.

F_{MgO} is the estimated fraction of cement clinker that is magnesium oxide.

Note The molecular weight ratio of carbon dioxide to calcium oxide is 0.785, and the molecular weight ratio of carbon dioxide to magnesium oxide is 1.092.

(3) Method 2 requires cement clinker to be sampled and analysed in accordance with sections 4.6 and 4.7.

4.6 General requirements for sampling cement clinker

(1) A sample of cement clinker must be derived from a composite of amounts of the cement clinker produced.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard.

Note An appropriate standard is AS 4264.4—1996, *Coal and coke – Sampling* Part 4: *Determination of precision and bias.*

(5) The value obtained from the sample must only be used for the production period for which it was intended to be representative.

4.7 General requirements for analysing cement clinker

(1) Analysis of a sample of cement clinker, including determining the fraction of the sample that is calcium oxide or magnesium oxide, must be done in accordance with industry practice and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of cement clinker must be in accordance with the Tier 3 method for cement clinker in section 2.2.1.1 in Part 1 of Volume 3 of the 2006 IPCC Guidelines.

4.8 Method 3 — cement clinker production

(1) Method 3 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each pure carbonate calcined in the production of cement clinker during the year as follows:

$$E_{ij} = \left(EF_{ij} \times Q_i \times F_{cal}\right) - A_{ckd} \times EF_{ckd} \times \left(1 - F_{ckd}\right) + Q_{toc} \times EF_{toc}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from the carbonate (***i***) calcined in the production of cement clinker during the year measured in CO_2-e tonnes.

EF_{ij} is the carbon dioxide (***j***) emission factor for the carbonate (***i***) measured in tonnes of emissions of carbon dioxide per tonne of pure carbonate, as follows:

(a) for calcium carbonate — 0.440; and
(b) for magnesium carbonate — 0.522; and
(c) for dolomite — 0.477; and
(d) for any other pure carbonate — the factor for the carbonate in accordance with section 2.1 of Part 1 of Volume 3 of the 2006 IPCC Guidelines.

Q_i is the quantity of the pure carbonate (***i***) consumed in the calcining process for the production of cement clinker during the year measured in tonnes and estimated under Division 4.2.5.

F_{cal} is:

(a) the amount of the carbonate calcined in the production of cement clinker during the year, expressed as a decimal fraction; or
(b) if the information mentioned in paragraph (a) is not available — the value 1.

A_{ckd} is the quantity of cement kiln dust lost from the kiln in the production of cement clinker during the year measured in tonnes and estimated under Division 4.2.5.

EF_{ckd} is 0.440, which is the carbon dioxide emission factor for calcined cement kiln dust lost from the kiln.

F_{ckd} is:

(a) the fraction of calcination achieved for cement kiln dust lost from the kiln in the production of cement clinker during the year; or

(b) if the information mentioned in paragraph (a) is not available — the value 1.

Q_{toc} is the quantity of total carbon-bearing non-fuel raw material consumed in the production of cement clinker during the year measured in tonnes and estimated under Division 4.2.5.

EF_{toc} is 0.010, which is the emission factor for carbon-bearing non-fuel raw material, measured in tonnes of carbon dioxide produced per tonne of carbon.

Step 2 Add together the amount of emissions of carbon dioxide as measured in CO_2-e tonnes released for each pure carbonate calcined in the production of cement clinker during the year.

(2) For the factor EF_{ckd} in subsection (1), the carbon dioxide emission factor for calcined cement kiln dust is assumed to be the same as the emission factor for calcium carbonate.

(3) For the factor Q_{toc} in subsection (1), the quantity of carbon-bearing non-fuel raw material must be estimated in accordance with Division 4.2.5 as if a reference to carbonates consumed from the activity was a reference to carbon-bearing non-fuel raw material consumed from the activity.

(4) Method 3 requires carbonates to be sampled and analysed in accordance with sections 4.9 and 4.10.

4.9 General requirements for sampling carbonates

(1) Method 3 requires carbonates to be sampled in accordance with the procedure for sampling cement clinker specified under section 4.6 for method 2.

(2) In applying section 4.6, a reference in that section to cement clinker is taken to be a reference to a carbonate.

4.10 General requirements for analysing carbonates

(1) Analysis of samples of carbonates, including determining the quantity (in tonnes) of pure carbonate, must be done in accordance with industry practice or standards, and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of carbonates must be in accordance with the Tier 3 method in section 2.2.1.1 of Part 1 of Volume 3 of the 2006 IPCC Guidelines.

Division 4.2.2 Lime production

4.11 Application

This Division applies to UNFCCC Category 2.A.2 — lime production (other than the in-house production of lime in the ferrous metals industry).

4.12 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of lime (other than the in-house production of lime in the ferrous metals industry):

(a) method 1 under section 4.13;
(b) method 2 under section 4.14;
(c) method 3 under section 4.17;
(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.13 Method 1 — lime production

Method 1 is:

$$E_{ij} = A_i \times EF_{ij}$$

where:

E

E_{ij} is the emissions of carbon dioxide (***j***) released from the production of lime (***i***) during the year measured in CO_2-e tonnes.

A_i is the quantity of lime produced during the year measured in tonnes and estimated under Division 4.2.5.

EF_{ij} is the carbon dioxide (***j***) emission factor for lime measured in tonnes of emission of carbon dioxide per tonne of lime produced, as follows:

(a) for commercial lime production — 0.675;
(b) for non-commercial lime production — 0.730.

4.14 Method 2 — lime production

(1) Subject to this section, method 2 is the same as method 1 under section 4.13.

(2) In applying method 1 under section 4.13, $\boldsymbol{EF_{ij}}$ is taken to be:

$$\mathrm{EF_{ij}} = \mathrm{F_i} \times \frac{44.01}{56.08}$$

where:

$\boldsymbol{F_i}$ is the estimated fractional purity of lime.

Note 44.01 is the molecular weight of carbon dioxide, and 56.08 is the molecular weight of calcium oxide.

(3) Method 2 requires lime to be sampled and analysed in accordance with sections 4.15 and 4.16.

4.15 General requirements for sampling

(1) A sample of lime must be derived from a composite of amounts of the lime produced.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard.

Note An appropriate standard is AS 4264.4—1996 – *Coal and coke – sampling – Determination of precision and bias.*

(5) The value obtained from the sample must only be used for the production period for which it was intended to be representative.

4.16 General requirements for analysis of lime

(1) Analysis of a sample of lime, including determining the fractional purity of the sample, must be done in accordance with industry practice and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of lime must be in accordance with the Tier 3 method in section 2.2.1.1 of Part 1 of Volume 3 of the 2006 IPCC Guidelines.

4.17 Method 3 — lime production

(1) Method 3 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each pure carbonate calcined in the production of lime during the year as follows:

$$E_{ij} = (EF_{ij} \times Q_i \times F_{cal}) - A_{lkd} \times EF_{lkd} \times (1 - F_{lkd})$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from a carbonate (***i***) calcined in the production of lime during the year measured in CO_2-e tonnes.

EF_{ij} is the carbon dioxide (***j***) emission factor for the carbonate (***i***), measured in tonnes of emissions of carbon dioxide per tonne of pure carbonate as follows:

(a) for calcium carbonate — 0.440;
(b) for magnesium carbonate — 0.522;
(c) for dolomite — 0.477;
(d) for any other carbonate — the factor for the carbonate in accordance with Tier 3 of Part 1 of Volume 3 of the 2006 IPCC Guidelines.

Q_i is the quantity of the pure carbonate (***i***) entering the calcining process in the production of lime during the year measured in tonnes and estimated under Division 4.2.5.

F_{cal} is:

(a) the amount of the carbonate calcined in the production of lime during the year expressed as a decimal fraction; or
(b) if the information mentioned in paragraph (a) is not available — the value 1.

A_{lkd} is the quantity of lime kiln dust lost in the production of lime during the year, measured in tonnes and estimated under Division 4.2.5.

EF_{lkd} is 0.440, which is the emission factor for calcined lime kiln dust lost from the kiln.

F_{lkd} is:

(a) the fraction of calcination achieved for lime kiln dust in the production of lime during the year; or
(b) if the data in paragraph (a) is not available — the value 1.

Step 2 Add together the amount of emissions of carbon dioxide for each pure carbonate calcined in the production of lime during the year.

(2) For the factor $\boldsymbol{EF_{lkd}}$ in subsection (1), the emission factor for calcined lime kiln dust is assumed to be the same as the emission factor for calcium carbonate.

(3) Method 3 requires each carbonate to be sampled and analysed in accordance with sections 4.18 and 4.19.

4.18 General requirements for sampling

(1) For section 4.17, carbonates must be sampled in accordance with the procedure for sampling lime specified under section 4.15 for method 2.

(2) In applying section 4.15, a reference in that section to lime is taken to be a reference to carbonates.

4.19 General requirements for analysis of carbonates

(1) For section 4.17, samples must be analysed in accordance with the procedure for analysing lime specified under section 4.16 for method 2.

(2) In applying section 4.16, a reference in that section to lime is taken to be a reference to carbonates.

Division 4.2.3 Other uses of carbonates

4.20 Application

This Division applies to UNFCCC Category 2.A.3 — industrial processes (other than cement clinker production or lime production) involving the calcination of carbonates, including the in-house production of lime in the ferrous metals industry.

Note Examples of industrial processes involving the calcination of carbonates include the following:

- metallurgy
- glass manufacture, including fibreglass and mineral wools
- magnesia production
- agriculture
- construction
- environment pollution control.

4.21 Available methods

(1) Subject to section 1.18 one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility constituted by the calcination of carbonates (the ***industrial process***) in an industrial process (other than cement clinker production or lime production):

(a) method 1 under section 4.22;
(b) method 3 under section 4.23;
(c) method 4 under Part 1.3.

Note There is no method 2 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.22 Method 1 — industrial processes involving calcination of carbonates

Method 1 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each raw carbonate material calcined in the industrial process during the year as follows:

$$E_{ij} = Q_i \times EF_{ij} \times F_{cal}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from raw carbonate material (***i***) calcined in the industrial process during the year measured in CO_2-e tonnes.

Q_i is the quantity of the raw carbonate material (***i***) consumed in the calcining process for the industrial process during the year measured in tonnes and estimated under Division 4.2.5.

EF_{ij} is the carbon dioxide (***j***) emission factor for the raw carbonate material (***i***) measured in tonnes of emissions of carbon dioxide per tonne of carbonate, that is:

(a) for calcium carbonate — 0.396; and
(b) for magnesium carbonate — 0.522; and
(c) for dolomite — 0.453; and
(d) for any other raw carbonate material — the factor for the raw carbonate material in accordance with section 2.1 of Part 1 of Volume 3 of the 2006 IPCC Guidelines.

F_{cal} is:

(a) the fraction of the raw carbonate material calcined in the industrial process during the year; or

(b) if the information in paragraph (a) is not available — the value 1.

Step 2 Add together the amount of emissions of carbon dioxide for each carbonate calcined in the industrial process during the year.

Note For the factor ***EFij*** in step 1, the emission factor value given for a raw carbonate material is based on a method of calculation that ascribed the following content to the material:

(a) for calcium carbonate — at least 90% calcium carbonate;

(b) for magnesium carbonate — 100% magnesium carbonate;

(c) for dolomite — at least 95% dolomite.

4.23 Method 3 — industrial processes involving calcination of carbonates

(1) Method 3 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each pure carbonate calcined in the industrial process during the year as follows:

$$E_{ij} = EF_{ij} \times Q_i \times F_{cal}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) from a pure carbonate (***i***) calcined in the industrial process during the year measured in CO_2-e tonnes.

EF_{ij} is the carbon dioxide (***j***) emission factor for the pure carbonate (***i***) in tonnes of emissions of carbon dioxide per tonne of pure carbonate, that is:

(a) for calcium carbonate — 0.440;

(b) for magnesium carbonate — 0.522;

(c) for dolomite — 0.477;

(d) for any other pure carbonate — the factor for the carbonate in accordance with Part 1 of Volume 3 of the 2006 IPCC Guidelines.

Q_i is the quantity of the pure carbonate (***i***) entering the calcination process for the industrial process during the year measured in tonnes and estimated under Division 4.2.5.

F_{cal} is:

(a) the fraction of the pure carbonate calcined in the industrial process during the year; or

(b) if the information in paragraph (a) is not available — the value 1.

Step 2 Add together the amount of emissions of carbon dioxide for each pure carbonate calcined in the industrial process during the year.

(2) Method 3 requires each carbonate to be sampled and analysed in accordance with sections 4.24 and 4.25.

4.24 General requirements for sampling carbonates

(1) A sample of a carbonate must be derived from a composite of amounts of the carbonate consumed.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard.

Note An example of an appropriate standard is AS 4264.4—1996 – *Coal and coke – sampling – Determination of precision and bias.*

(5) The value obtained from the samples must only be used for the delivery period or consignment of the carbonate for which it was intended to be representative.

4.25 General requirements for analysis of carbonates

(1) Analysis of samples of carbonates must be in accordance with industry practice and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of carbonates must be in accordance with the Tier 3 method of section 2.2.1.1 of Part 1 of Volume 3 of the 2006 IPCC Guidelines.

Division 4.2.4 Soda ash use and production

4.26 Application

This Division applies to UNFCCC Category 2.A.4 — the use and production of soda ash.

Note Examples of uses of soda ash in industrial processes include the following:

- glass production

- soap and detergent production
- flue gas desulphurisation
- pulp and paper production.

4.27 Outline of Division

Emissions released from the use and production of soda ash must be estimated in accordance with:

(a) for the use of soda ash in production processes — Subdivision 4.2.4.1; or

(b) for the production of soda ash — Subdivision 4.2.4.2.

Subdivision 4.2.4.1 Soda ash use

4.28 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility constituted by the use of soda ash in a production process:

(a) method 1 under section 4.29;

(b) method 4 under Part 1.3.

Note There is no method 2 or 3 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.29 Method 1 — use of soda ash

Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) from soda ash (***i***) consumed in the production process during the year measured in CO_2-e tonnes.

Q_i is the quantity of soda ash (***i***) consumed in the production process during the year measured in tonnes and estimated under Division 4.2.5.

EF_{ij} is 0.415, which is the carbon dioxide (***j***) emission factor for soda ash (***i***) measured in tonnes of carbon dioxide emissions per tonne of soda ash.

Subdivision 4.2.4.2 Soda ash production

4.30 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a year from the operation of a facility constituted by the production of soda ash:

(a) method 1 under section 4.31;

(b) method 2 under section 4.32;

(c) method 3 under section 4.33;

(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.31 Method 1 — production of soda ash

(1) Method 1 is:

$$E_{ij} = Q_i \times EC_i \times \left(\frac{EF_{ij}}{1000} \right)$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of each gas type (***j***), that is carbon dioxide, methane and nitrous oxide, released from the feedstock type (***i***) consumed from the production of soda ash during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of the feedstock type (***i***) consumed from the production of soda ash during the year measured in the appropriate unit and estimated under Division 2.2.5, 2.3.6 or 2.4.6.

$\boldsymbol{EC_i}$ is the energy content factor for the feedstock type (***i***), as mentioned in Schedule 1 measured in gigajoules per the appropriate unit.

$\boldsymbol{EF_{ij}}$ is the gas type (***j***) emission factor for the feedstock type (***i***), including the effects of oxidation, as mentioned in Schedule 1, measured in CO_2-e kilograms per gigajoule.

Note Emissions of carbon dioxide, methane and nitrous oxide are released from the production of soda ash.

(2) If $\boldsymbol{Q_i}$ is measured in gigajoules, then $\boldsymbol{EC_i}$ is 1.

4.32 Method 2 — production of soda ash

(1) Subject to this section, method 2 is the same as method 1 under section 4.31.

(2) In applying method 1 under section 4.31, the facility specific emission factor (EF_{ij}) must be determined in accordance with the following:

(a) for estimating emissions released from the production of soda ash using solid fuels — the procedure for determining EF_{ico_2oxec} in method 2 under Division 2.2.3;

(b) for estimating emissions released from the production of soda ash using gaseous fuels — the procedure for determining EF_{ico_2oxec} in method 2 under Division 2.3.3;

(c) for estimating emissions released from the production of soda ash using liquid fuels — the procedure for determining EF_{ico_2oxec} in method 2 under Division 2.4.3.

4.33 Method 3 — production of soda ash

(1) Subject to this section, method 3 is the same as method 1 under section 4.31.

(2) In applying method 1 under section 4.31, the facility specific emission factor EF_i must be determined in accordance with the following:

(a) for estimating emissions released from the production of soda ash using solid fuels — the procedure for determining EF_{ico_2oxec} in method 3 under Division 2.2.4;

(b) for estimating emissions released from the production of soda ash using gaseous fuels — the procedure for determining EF_{ico_2oxec} in method 3 under Division 2.3.4;

(c) for estimating emissions released from the production of soda ash using liquid fuels — the procedure for determining EF_{ico_2oxec} in method 3 under Division 2.4.4.

Division 4.2.5 Measurement of quantity of carbonates consumed and products derived from carbonates

4.34 Purpose of Division

(1) This Division applies to the operation of a facility (the ***activity***) that is constituted by:

(a) the production of cement clinker; or

(b) the production of lime; or

(c) the calcination of carbonates in an industrial process; or

(d) the use and production of soda ash.

(2) This Division sets out how the quantities of carbonates consumed from the operation of the activity, and the quantities of products derived from carbonates produced from the operation of the activity, are to be estimated for the following:

(a) A_i and A_{ckd} in section 4.4;

(b) Q_i and Q_{toc} in section 4.8;

(c) A_i in section 4.13;

(d) Q_i and A_{lkd} in section 4.17;

(e) Q_i in sections 4.22, 4.23, and 4.29.

4.35 Criteria for measurement

Quantities of carbonates consumed from the operation of the activity, or quantities of products derived from carbonates produced from the operation of the activity, must be estimated using one of the following criteria:

(a) the amount of carbonates delivered for the activity, or the amount of products derived from carbonates dispatched from the activity, during the year as evidenced by invoices issued by the vendor of the carbonates or the products derived from carbonates (***criterion A***);

(b) as provided in section 4.36 (***criterion AA***);

(c) as provided in section 4.37 (***criterion AAA***);

(d) as provided in section 4.38 (***criterion BBB***).

4.36 Indirect measurement at point of consumption or production — criterion AA

(1) For paragraph 4.35(b), criterion AA is the amount of carbonates consumed from the operation of the activity, or the amount of products derived from carbonates produced from the operation of the activity, during the year based on amounts delivered or dispatched during the year:

(a) as evidenced by invoices; and

(b) as adjusted for the estimated change in the quantity of the stockpiles of carbonates or the quantity of the stockpiles of products derived from carbonates during the year.

(2) The volume of carbonates, or products derived from carbonates, in the stockpile for the activity must be measured in accordance with industry practice.

4.37 Direct measurement at point of consumption or production — criterion AAA

(1) For paragraph 4.35 (c), criterion AAA is the direct measurement during the year of:

(a) the quantities of carbonates consumed from the operation of the activity; or

(b) the quantities of products derived from carbonates produced from the operation of the activity.

(2) The measurement must be:

(a) carried out using measuring equipment calibrated to a measurement requirement; or

(b) for measurement of the quantities of carbonates consumed from the operation of the activity — carried out at the point of sale using measuring equipment calibrated to a measurement requirement.

(3) Paragraph (2) (b) only applies if:

(a) the change in the stockpile of the carbonates for the activity during the year is less than 1% of total consumption of the carbonates from the operation of the activity on average during the year; and

(b) the stockpile of the carbonates for the activity at the beginning of the year is less than 5% of total consumption of the carbonates from the operation of the activity during the year.

4.38 Acquisition or use or disposal without commercial transaction — criterion BBB

For paragraph 4.35 (d), criterion BBB is the estimation of the consumption of carbonates, or the products derived from carbonates, during the year in accordance with industry practice if:

(a) the delivery of the carbonates, or the dispatch of the products derived from carbonates, does not involve a commercial transaction; and

(b) the equipment used to measure consumption of the carbonates, or the products derived from carbonates, is not calibrated to a measurement requirement.

4.39 Units of measurement

Measurements of carbonates and products derived from carbonates must be converted to units of tonnes.

Part 4.3 Industrial processes — chemical industry

Division 4.3.1 Ammonia production

4.40 Application

This Division applies to UNFCCC Category 2.B.1 — chemical industry ammonia production.

4.41 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by the production of ammonia:

(a) method 1 under section 4.42;
(b) method 2 under section 4.43;
(c) method 3 under section 4.44;
(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.42 Method 1 — ammonia production

(1) Method 1 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000} - R$$

where:

E_{ij} is the emissions of carbon dioxide released from the production of ammonia during the year measured in CO_2-e tonnes.

Q_i is the quantity of each type of feedstock or type of fuel (***i***) consumed from the production of ammonia during the year, measured in the appropriate unit and estimated using a criterion in Division 2.3.6.

EC_i is the energy content factor of the type of feedstock or type of fuel (***i***) used in the production of ammonia during the year, measured in gigajoules per cubic metre according to the source mentioned in Part 2 of Schedule 1.

EF_{ij} is the carbon dioxide emission factor for each type of feedstock or type of fuel (***i***) used in the production of ammonia during the year, including the effects of oxidation, measured in kilograms for each gigajoule according to source as mentioned in Part 2 of Schedule 1.

R is the quantity of carbon dioxide derived from the production of ammonia during the year, captured and transferred for use in the operation of another facility, estimated using an applicable criterion in Division 2.3.6 and in accordance with any other requirements of that Division.

(2) If Q_i is measured in gigajoules, then EC_i is 1.

4.43 Method 2 — ammonia production

(1) Subject to this section, method 2 is the same as method 1 under section 4.42.

(2) In applying method 1 under section 4.42, the method for estimating emissions for gaseous fuels in Division 2.3.3 applies for working out the factor EF_{ij}.

4.44 Method 3 — ammonia production

(1) Subject to this section, method 3 is the same as method 1 under section 4.42.

(2) In applying method 1 under section 4.42, the method for estimating emissions for gaseous fuels in Division 2.3.4 applies for working out the factor EF_{ij}.

Division 4.3.2 Nitric acid production

4.45 Application

This Division applies to UNFCCC Category 2.B.2 — chemical industry nitric acid production.

4.46 Available methods

(1) Subject to section 1.18 and this section, one of the following methods must be used for estimating emissions during a year from the operation of a facility that is constituted by the production of nitric acid at a plant:

(a) method 1 under section 4.47;
(b) method 2 under section 4.48;
(c) method 4 under Part 1.3.

Note There is no method 3 for this Division.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

(3) Method 1 must not be used if the plant has used measures to reduce nitrous oxide emissions.

4.47 Method 1 — nitric acid production

(1) Method 1 is:

$$E_{ijk} = EF_{ijk} \times A_{ik}$$

where:

E**$_{ijk}$* is the emissions of nitrous oxide released during the year from the production of nitric acid at plant type (k***) measured in CO_2-e tonnes.

EF**$_{ijk}$* is the emission factor of nitrous oxide for each tonne of nitric acid produced during the year from plant type (k***).

A**$_{ik}$* is the quantity, measured in tonnes, of nitric acid produced during the year from plant type (k***).

(2) For ***EF**$_{ijk}$* in subsection (1), column 3 of an item in the following table specifies the emission factor of nitrous oxide for each tonne of nitric acid produced from a plant type (***k)*** specified in column 2 of that item.

Item	Plant type (*k*)	Emission factor of nitrous oxide (tonnes CO_2-e per tonne of nitric acid production)
1	Atmospheric pressure plants	1.55
2	Medium pressure combustion plant	2.17
3	High pressure plant	2.79

Note The emission factors specified in this table apply only to method 1 and the operation of a facility that is constituted by a plant that has not used measures to reduce nitrous oxide emissions.

4.48 Method 2 — nitric acid production

(1) Subject to this section, method 2 is the same as method 1 under section 4.47.

(2) In applying method 1 under section 4.47, to work out the factor ***EF**$_{ijk}$*:

(a) periodic emissions monitoring must be used and conducted in accordance with Part 1.3; and

(b) the emission factor must be measured as nitrous oxide in CO_2-e tonnes for each tonne of nitric acid produced during the year from the plant.

(3) For method 2, all data on nitrous oxide concentrations, volumetric flow rates and nitric acid production for each sampling period must be used to estimate the flow-weighted average emission rate of nitrous oxide for each unit of nitric acid produced from the plant.

Division 4.3.3 Adipic acid production

4.49 Application

This Division applies to UNFCCC Category 2.B.3 — chemical industry adipic acid production.

4.50 Available methods

(1) Subject to section 1.18, one of the methods for measuring emissions released in the production of adipic acid set out in section 3.4 of the 2006 IPCC Guidelines must be used for estimating emissions during a year from the operation of a facility that is constituted by the production of adipic acid.

(2) For incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Division 4.3.4 Carbide production

4.51 Application

This Division applies to UNFCCC Category 2.B.4 — chemical industry carbide production.

4.52 Available methods

(1) Subject to section 1.18, one of the methods for measuring emissions from carbide production set out in section 3.6 of the 2006 IPCC Guidelines must be used for estimating emissions during a year from the operation of a facility that is constituted by carbide production.

(2) For incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Division 4.3.5 Titanium dioxide

4.53 Application

This Division applies to UNFCCC Category 2.B.5 — chemical industry titanium dioxide production.

4.54 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by the production of titanium dioxide:

(a) method 1 under section 4.55;
(b) method 2 under section 4.56;
(c) method 3 under section 4.57;
(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.55 Method 1 — titanium dioxide production

(1) Method 1 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000}$$

where:

E_{ij} is the emissions of carbon dioxide released from the fuel type (***i***) used in the production of titanium dioxide during the year and measured in CO_2-e tonnes.

Q_i is the quantity of each fuel type (***i***) consumed in the production of titanium dioxide from the production of titanium dioxide during the year measured in the appropriate unit and estimated in accordance with:

(a) for solid fuels — Division 2.2.5, or
(b) for gaseous fuels — Division 2.3.6; or
(c) for liquid fuels — Division 2.4.6.

EC_i is the energy content factor of the fuel type (***i***) used in the production of titanium dioxide during the year, measured in gigajoules per the unit of measurement mentioned in column 3 of a table in Schedule 1 for the fuel type according to source as mentioned in:

(a) for solid fuel combustion — Part 1 of Schedule 1; and
(b) for gaseous fuel combustion — Part 2 of Schedule 1; and
(c) for liquid fuel combustion for stationery energy purposes — Part 3 of Schedule 1.

EF_{ij} is the carbon dioxide emission factor for the fuel type (***i***) used in the production of titanium dioxide during the year, including effects of oxidation, measured in kilograms for each gigajoule according to source as mentioned in:

(a) for solid fuel combustion — Part 1 of Schedule 1; and

(b) for gaseous fuel combustion — Part 2 of Schedule 1; and

(c) for liquid fuel combustion for stationery energy purposes — Part 3 of Schedule 1.

(2) If $\boldsymbol{Q_i}$ is measured in gigajoules, then $\boldsymbol{EC_i}$ is 1.

4.56 Method 2 — titanium dioxide production

Method 2 is:

(a) for estimating emissions released in the production of titanium dioxide using solid fuels during the year — the same as method 2 under Division 2.2.3; and

(b) for estimating emissions released in the production of titanium dioxide using gaseous fuels during the year — the same as method 2 under Division 2.3.3; and

(c) for estimating emissions released in the production of titanium dioxide using liquid fuels during the year — the same as method 2 under Division 2.4.3.

4.57 Method 3 — titanium dioxide production

Method 3 is:

(a) for estimating emissions released in the production of titanium dioxide using solid fuels during the year — the same as method 3 under Division 2.2.4; and

(b) for estimating emissions released in the production of titanium dioxide using gaseous fuels during the year — the same as method 3 under Division 2.3.4; and

(c) for estimating emissions released in the production of titanium dioxide using liquid fuels during the year — the same as method 3 under Division 2.4.4.

Division 4.3.6 Synthetic rutile production

4.58 Application

This Division applies to UNFCCC Category 2.B.5 — chemical industry synthetic rutile production.

4.59 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions during a year from the operation of a facility that is constituted by the production of synthetic rutile:

(a) method 1 under section 4.60;

(b) method 2 under section 4.61;

(c) method 3 under section 4.62;

(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.60 Method 1 — synthetic rutile production

(1) Method 1 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000}$$

where:

***E*$_{ij}$** is the emissions of carbon dioxide released as a result of the consumption of a carbon reductant in the production of synthetic rutile during the year measured in CO_2-e tonnes.

Q*$_i$** is the quantity of each fuel type (i***) consumed as a carbon reductant in the production of synthetic rutile during the year measured in the appropriate unit and estimated in accordance with:

(a) for solid fuels — Division 2.2.5; or

(b) for gaseous fuels — Division 2.3.6; or

(c) for liquid fuels — Division 2.4.6.

EC*$_i$** is the energy content factor of the fuel type (i***), used in the production of synthetic rutile during the year, measured in gigajoules per the appropriate unit for the fuel type according to source as mentioned in:

(a) for solid fuel — Part 1 of Schedule 1; and

(b) for gaseous fuel — Part 2 of Schedule 1; and

(c) for liquid fuel for stationery energy purposes — Part 3 of Schedule 1.

EF*$_{ij}$** is the carbon dioxide emission factor for the fuel type (i***) used in the production of synthetic rutile during the year, including effects of oxidation, measured in kilograms for each gigajoule according to source as mentioned in:

(a) for solid fuel combustion — Part 1 of Schedule 1; and

(b) for gaseous fuel combustion — Part 2 of Schedule 1; and

(c) for liquid fuel combustion for stationery energy purposes — Part 3 of Schedule 1.

(2) If ***Q*$_i$** is measured in gigajoules, then ***EC*$_i$** is 1.

4.61 Method 2 — synthetic rutile production

Method 2 is:

(a) for estimating emissions released in the consumption of a carbon reductant in the production of synthetic rutile using solid fuels — the same as method 2 under Division 2.2.3; and

(b) for estimating emissions released in the consumption of a carbon reductant in the production of synthetic rutile using gaseous fuels — the same as method 2 under Division 2.3.3; and

(c) for estimating emissions released in the consumption of a carbon reductant in the production of synthetic rutile using liquid fuels — the same as method 2 under Division 2.4.3.

4.62 Method 3 — synthetic rutile production

Method 3 is:

(a) for estimating emissions released in the consumption of a carbon reductant in the production of synthetic rutile using solid fuels — the same as method 3 under Division 2.2.4; and

(b) for estimating emissions released in the consumption of a carbon reductant in the production of synthetic rutile using gaseous fuels — the same as method 3 under Division 2.3.4; and

(c) for estimating emissions released in the consumption of a carbon reductant in the production of synthetic rutile using liquid fuels — the same as method 3 under Division 2.4.4.

Part 4.4 Industrial processes — metal industry

Division 4.4.1 Iron and steel production

4.63 Application

This Division applies to UNFCCC Category 2.C.1 — iron and steel production.

Note Iron and steel production has 2 primary sources of emissions. The emissions are from the combustion of fuels for making coke and from the use of fuel as a carbon reductant in iron and steel production. Other sources include emissions from use of carbonates.

4.64 Purpose of Division

(1) This Division applies to determining emissions released during a year from the operation of a facility that is constituted by an activity that produces iron and steel, for example, an integrated steelworks.

(2) An ***integrated steelworks*** means a steelworks that produces coke, iron and steel.

(3) The emissions from the activity are to be worked out as a total of emissions released from the production of iron and steel and from all other emissions released from the operation of the activity (including the production of coke if the activity is an integrated steelworks).

(4) However, the amount of emissions to be applied to UNFCCC Category 2.C.1 is only the amount of emissions from the use of coke as a carbon reductant in the iron and steel production estimated in accordance with section 2.69.

Note The amount of emissions to be applied to other UNFCCC Categories is as provided for in other provisions of this Determination.

4.65 Available methods for iron and steel production

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released from the activity during a year:

(a) method 1 under section 4.66;
(b) method 2 under section 4.67;
(c) method 3 under section 4.68;
(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.66 Method 1 — iron and steel production

Method 1, based on a carbon mass balance approach, is:

Step 1 Calculate the carbon content in fuel types (***i***) or carbonaceous input material delivered for the activity during the year measured in tonnes of carbon as follows:

$$\Sigma_i \ CCF_i \times Q_i$$

where:

$\boldsymbol{\Sigma_i}$ means sum the carbon content values obtained for all fuel types (***i***) or carbonaceous input material.

$\boldsymbol{CCF_i}$ is the carbon content factor mentioned in Schedule 3 measured in tonnes of carbon for each appropriate unit of fuel type (***i***) or carbonaceous input material consumed during the year from the operation of the activity.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) or carbonaceous input material delivered for the activity during the year measured in an appropriate unit and estimated in accordance with criterion A in Division 2.2.5, 2.3.6 and 2.4.6.

Step 2 Calculate the carbon content in products (***p***) leaving the activity during the year measured in tonnes of carbon as follows:

$$\Sigma_p \ CCF_p \times A_p$$

where:

$\boldsymbol{\Sigma_p}$ means sum the carbon content values obtained for all product types (***p***).

$\boldsymbol{CCF_p}$ is the carbon content factor measured in tonnes of carbon for each tonne of product type (***p***) produced during the year.

$\boldsymbol{A_p}$ is the quantity of product types (***p***) produced leaving the activity during the year measured in tonnes.

Step 3 Calculate the carbon content in waste by-product types ***(r)*** leaving the activity, other than as an emission of greenhouse gas, during the year, measured in tonnes of carbon, as follows:

$$\Sigma_r \ CCF_r \times Y_r$$

where:

Σ_r means sum the carbon content values obtained for all waste by-product types (***r***).

CCF_r is the carbon content factor measured in tonnes of carbon for each tonne of waste by-product types (***r***).

Y_r is the quantity of waste by-product types (***r***) leaving the activity during the year measured in tonnes.

Step 4 Calculate the carbon content in the amount of the increase in stocks of inputs, products and waste by-products held within the boundary of the activity during the year in tonnes of carbon as follows:

$$\Sigma_i \, CCF_i \times \Delta S_{qi} + \Sigma_p \, CCF_p \times \Delta S_{ap} + \Sigma_r \, CCF_r \times \Delta S_{yr}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

ΔS_{qi} is the increase in stocks of fuel type (***i***) for the activity and held within the boundary of the activity during the year measured in tonnes.

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

ΔS_{ap} is the increase in stocks of product types (***p)*** produced by the activity and held within the boundary of the activity during the year measured in tonnes.

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the increase in stocks of waste by-product types (***r***) produced from the operation of the activity and held within the boundary of the activity during the year measured in tonnes.

Step 5 Calculate the emissions of carbon dioxide released from the operation of the activity during the year measured in CO_2-e tonnes as follows:

(a) add the amounts worked out under steps 2, 3 and 4 to work out a new amount (***amount A***);

(b) subtract amount A from the amount worked out under step 1 to work out a new amount (***amount B***);

(c) multiply amount B by 3.664 to work out the amount of emissions released from the operation of the activity during a year.

4.67 Method 2 — iron and steel production

(1) Subject to this section, method 2 is the same as method 1.

(2) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(3) The sampling and analysis is to be carried out using the sampling and analysis provided for in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, liquid or gaseous fuels.

4.68 Method 3 — iron and steel production

(1) Subject to this section, method 3 is the same as method 1.

(2) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(3) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, liquid or gaseous fuels:

Division 4.4.2 Ferroalloy metal

4.69 Application

This Division applies to UNFCCC Category 2.C.2 — ferroalloy production.

4.70 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide during a year from the operation of a facility that is constituted by the production of ferroalloy metal:

(a) method 1 under section 4.71;
(b) method 2 under section 4.72;
(c) method 3 under section 4.73;
(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.71 Method 1 — ferroalloy metal

(1) Method 1 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1\,000}$$

where:

E*ij* is the emissions of carbon dioxide released from the consumption of a carbon reductant in the production of ferroalloy metal during the year, measured in CO_2-e tonnes.

Q*i* is the quantity of each carbon reductant (***i***), used in the production of ferroalloy metal during the year, measured in the appropriate unit and estimated in accordance with:

(a) for solid fuels — Division 2.2.5; or

(b) for gaseous fuels — Division 2.3.6; or

(c) for liquid fuels — Division 2.4.6.

EC*i* is the energy content factor of carbon reductant type (***i***), measured in gigajoules per the appropriate unit of reductant used in the production of ferroalloy metal during the year.

EF*ij* is the emission factor of carbon reductant type (***i***), measured in kilograms of CO_2-e per gigajoule of reductant used in the production of the ferroalloy metal during the year.

(2) In subsection (1):

(a) subject to subsection (3), for the factor ***ECi*** — the energy content factor of a carbon reductant means the energy content factor for that reductant as mentioned in Schedule 1; and

(b) for the factor ***EFij*** — the emission factor of each carbon reductant means the emission factor for that reductant as mentioned in Schedule 1.

(3) If ***Qi*** is measured in gigajoules, then ***ECi*** is 1.

4.72 Method 2 — ferroalloy metal

Method 2 is:

(a) for estimating emissions released from carbon reductants used in the production of ferroalloy metal using solid fuels — the same as method 2 under Division 2.2.3; and

(b) for estimating emissions released from carbon reductants used in the production of ferroalloy metal using gaseous fuels — the same as method 2 under Division 2.3.3; and

(c) for estimating emissions released from carbon reductants used in the production of ferroalloy metal using liquid fuels — the same as method 2 under Division 2.4.3.

4.73 Method 3 — ferroalloy metals

Method 3 is:

(a) for estimating emissions released from carbon reductants used in the production of ferroalloy metal using solid fuels — the same as method 3 under Division 2.2.4; and

(b) for estimating emissions released from carbon reductants used in the production of ferroalloy metal using gaseous fuels — the same as method 3 under Division 2.3.4; and

(c) for estimating emissions released from carbon reductants used in the production of ferroalloy metal using liquid fuels — the same as method 3 under Division 2.4.4.

Division 4.4.3 Aluminium (carbon dioxide emissions)

4.74 Application

This Division applies to UNFCCC Category 2.C.3 — aluminium production.

Subdivision 4.4.3.1 Aluminium — emissions from consumption of baked carbon anodes in aluminium production

4.75 Available methods

(1) Subject to section 1.18, for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of aluminium involving the consumption of baked carbon anodes, one of the following methods must be used:

(a) method 1 under section 4.76;

(b) method 2 under section 4.77;

(c) method 3 under section 4.78;

(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.76 Method 1 — aluminium (baked carbon anode consumption)

Method 1 is:

$$E_{ij} = A_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide released from aluminium smelting and production involving the consumption of baked carbon anodes during the year measured in CO_2-e tonnes.

$\boldsymbol{A_i}$ is the amount of primary aluminium produced in tonnes during the year.

$\boldsymbol{EF_{ij}}$ is the carbon dioxide emission factor for baked carbon anode consumption, measured in CO_2-e tonnes for each tonne of aluminium produced during the year, estimated in accordance with the following formula:

$$EF_{ij} = (NAC \times \left(\frac{100 - S_a - Ash_a}{100}\right) \times 3.664$$

where:

NAC is the amount of carbon consumed from a baked carbon anode consumed in the production of aluminium during the year, worked out at the rate of 0.413 tonnes of baked carbon anode consumed for each tonne of aluminium produced.

$\boldsymbol{S_a}$ is the sulphur content in baked carbon anodes consumed in the production of aluminium during the year, and taken to be an amount equal to 2% of the weight of the baked carbon anodes consumed.

$\boldsymbol{Ash_a}$ is the ash content in baked carbon anodes consumed in the production of aluminium during the year, and taken to be an amount equal to 0.4 % of the weight of the baked carbon anodes consumed.

4.77 Method 2 — aluminium (baked carbon anode consumption)

(1) Subject to this section, method 2 is the same as method 1 under section 4.76.

(2) In applying method 1 under section 4.76, the method for sampling and analysing the fuel type (***i***) for the factors ***NAC***, $\boldsymbol{S_a}$ and $\boldsymbol{Ash_a}$ must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

(a) for solid fuels — method 2 in Division 2.2.3; and

(b) for gaseous fuels — method 2 in Division 2.3.3; and

(c) for liquid fuels — method 2 in Division 2.4.3.

4.78 Method 3 — aluminium (baked carbon anode consumption)

(1) Subject to this section, method 3 is the same as method 1 under section 4.76.

(2) In applying method 1 under section 4.76, the method for sampling and analysing fuel type (***i***) for the factors ***NAC***, $\boldsymbol{S_a}$ and $\boldsymbol{Ash_a}$ must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

(a) for solid fuels — method 3 in Division 2.2.4; and

(b) for gaseous fuels — method 3 in Division 2.3.4; and

(c) for liquid fuels — method 3 in Division 2.4.4.

Subdivision 4.4.3.2 Aluminium — emissions from production of baked carbon anodes in aluminium production

4.79 Available methods

(1) Subject to section 1.18, for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of aluminium involving the production of baked carbon anodes, one of the following methods must be used:

(a) method 1 under section 4.80;

(b) method 2 under section 4.81;

(c) method 3 under section 4.82;

(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.80 Method 1 — aluminium (baked carbon anode production)

Method 1 is:

$$E_{ij} = (GA - Hw - BA - WT) \times 3.664 + \left(\frac{\Sigma Q_i}{BA} \times BA \times \frac{(100 - S_i - Ash_i)}{100} \right) \times 3.664$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide released from baked carbon anode production for the facility during the year.

GA is the initial weight of green anodes used in the production process of the baked carbon anode.

Hw is the weight of the hydrogen content in green anodes used in the production of the baked carbon anode during the year measured in tonnes.

BA is the amount of baked carbon anode produced during the year measured in tonnes.

WT is the amount, in tonnes, of waste tar collected in the production of baked carbon anodes during the year.

ΣQ_i is the quantity of fuel type (***i***), measured in the appropriate unit, consumed in the production of baked carbon anodes during the year and estimated in accordance with the requirements set out in the following Divisions:

(a) if fuel type (***i***) is a solid fuel — Division 2.2.5;

(b) if fuel type (***i***) is a gaseous fuel — Division 2.3.6;

(c) if fuel type (***i***) is a liquid fuel — Division 2.4.6.

S_i is the weight of sulphur in fuel type (***i***) consumed in the production of baked carbon anodes during the year, worked out as equal to 2% of the weight of the fuel.

Ash_i is the ash content in reductant fuel type (***i***) consumed in the production of baked carbon anodes during the year, worked out as equal to 0.4% of the weight of the fuel.

4.81 Method 2 — aluminium (baked carbon anode production)

(1) Subject to this section, method 2 is the same as method 1 under section 4.80.

(2) In applying method 1 under section 4.80, the method for sampling and analysing fuel type (***i***) for the factors S_i and Ash_i must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

(a) for solid fuels — method 2 in Division 2.2.3; and

(b) for gaseous fuels — method 2 in Division 2.3.3; and

(c) for liquid fuels — method 2 in Division 2.4.3.

4.82 Method 3 — aluminium (baked carbon anode production)

(1) Subject to this section, method 3 is the same as method 1 under section 4.80.

(2) In applying method 1 under section 4.80, the method for sampling and analysing the fuel type (***i***) for the factors S_i and Ash_i must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

(a) for solid fuels — method 3 in Division 2.2.4; and

(b) for gaseous fuels — method 3 in Division 2.3.4; and

(c) for liquid fuels — method 3 in Division 2.4.4.

Division 4.4.4 Aluminium (perfluoronated carbon compound emissions)

4.83 Application

This Division applies to UNFCCC Category 2.C.3 — aluminium production.

Subdivision 4.4.4.1 Aluminium — emissions of tetrafluoromethane in aluminium production

4.84 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of tetrafluoromethane released during a year from the operation of a facility that is constituted by the production of aluminium:

(a) method 1 under section 4.85;
(b) method 2 under section 4.86;
(c) method 3 under section 4.87.

Note There is no method 4 for this provision.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.85 Method 1 — aluminium (tetrafluoromethane)

Method 1 is:

$$E_{ij} = A_i \times EF_{ij}$$

where:

E_{ij} is the amount of emissions of tetrafluoromethane released from primary aluminium production during the year measured in CO_2-e tonnes.

A_i is the amount of primary aluminium production during the year measured in tonnes.

EF_{ij} is 0.26, which is the emission factor for tetrafluoromethane measured in CO_2-e tonnes for each tonne of aluminium produced during the year.

4.86 Method 2 — aluminium (tetrafluoromethane)

Method 2 is the Tier 2 method for estimating perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

4.87 Method 3 — aluminium (tetrafluoromethane)

Method 3 is the Tier 3 method for estimating facility-specific perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

Subdivision 4.4.4.2 Aluminium — emissions of hexafluoroethane in aluminium production

4.88 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of hexafluoroethane released during a year from the operation of a facility that is constituted by the production of aluminium:

(a) method 1 under section 4.89;
(b) method 2 under section 4.90;
(c) method 3 under section 4.91.

Note There is no method 4 for this provision.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.89 Method 1 — aluminium production (hexafluoroethane)

Method 1 is:

$$E_{ij} = A_i \times EF_{ij}$$

where:

E_{ij} is the emissions of hexafluoroethane released from primary aluminium production during the year measured in CO_2-e tonnes.

A_i is the amount of primary aluminium production during the year measured in tonnes.

EF_{ij} is 0.05, which is the emission factor for hexafluoroethane measured in CO_2-e tonnes for each tonne of aluminium produced during the year.

4.90 Method 2 — aluminium production (hexafluoroethane)

Method 2 is the Tier 2 method for estimating facility-specific perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

4.91 Method 3 — aluminium production (hexafluoroethane)

Method 3 is the Tier 3 method for estimating facility-specific perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

Division 4.4.5 Other metals

4.92 Application

This Division applies to Source 2 (UNFCCC Category 2.C.4) — other metals.

4.93 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide from the use of carbon reductants during a year from the operation of a facility that is constituted by the production of metals other than aluminium, ferroalloys and iron and steel:

(a) method 1 under section 4.94;
(b) method 2 under section 4.95;
(c) method 3 under section 4.96;
(d) method 4 under Part 1.3.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

4.94 Method 1 — other metals

(1) Method 1 is:

$$E_{ij} = \frac{Q_1 \times EC_i \times EF_i}{1\,000}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide released from the consumption of a carbon reductant in the production of a metal other than aluminium, ferroalloys and iron and steel during the year measured in the appropriate unit.

$\boldsymbol{Q_i}$ is the quantity of each carbon reductant type (***i***) consumed in the production of the metal during the year, measured in the appropriate unit and estimated in accordance with the requirements set out in the following Divisions:

(a) if fuel type (***i***) is a solid fuel — Division 2.2.5;
(b) if fuel type (***i***) is a gaseous fuel — Division 2.3.6;
(c) if fuel type (***i***) is a liquid fuel — Division 2.4.6.

$\boldsymbol{EC_i}$ is the energy content factor of the carbon reductant type (***i***) measured in gigajoules per the appropriate unit for the reductant used in the production of the metal during the year.

EF_i is the emission factor of each carbon reductant type (***i***) measured in kilograms of CO_2-e for each gigajoule of reductant consumed in the production of the metal during the year.

(2) In subsection (1):

(a) subject to subsection (3), for EC_i — the energy content factor of a carbon reductant means the energy content factor for that reductant as mentioned in Schedule 1; and

(b) for EF_i — the emission factor of each carbon reductant means the emission factor for that reductant as mentioned in Schedule 1.

(3) If Q_i is measured in gigajoules, then EC_i is 1.

4.95 Method 2 — other metals

Method 2 is:

(a) for estimating emissions released from carbon reductants consumed in the production of other metals using solid fuels — the same as method 2 under Division 2.2.3; and

(b) for estimating emissions released from carbon reductants consumed in the production of other metals using gaseous fuels — the same as method 2 under Division 2.3.3; and

(c) for estimating emissions released from carbon reductants consumed in the production of other metals using liquid fuels — the same as method 2 under Division 2.4.3.

4.96 Method 3 — other metals

Method 3 is:

(a) for estimating emissions released from carbon reductants consumed in the production of other metals using solid fuels — the same as method 3 under Division 2.2.4; and

(b) for estimating emissions released from carbon reductants consumed in the production of other metals using gaseous fuels — the same as method 3 under Division 2.3.4; and

(c) for estimating emissions released from carbon reductants consumed in the production of other metals using liquid fuels — the same as method 3 under Division 2.4.4.

Part 4.5 Industrial processes — emissions of hydrofluorocarbons and sulphur hexafluoride gases

4.97 Application

This Part applies to UNFCCC Category 2.F — emissions of hydrofluorocarbons and sulphur hexafluoride gases.

4.98 Available method

(1) Subject to section 1.18, method 1 under section 4.102 must be used for estimating emissions of hydrofluorocarbons or sulphur hexafluoride during a year from the operation of a facility that is constituted by synthetic gas generating activities.

(2) However, for incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Note There is no method 2, 3 or 4 for this Part.

4.99 Meaning of *hydrofluorocarbons*

Hydrofluorocarbons means any of the hydrofluorocarbons listed in the table in regulation 2.04 of the Regulations.

4.100 Meaning of *synthetic gas generating activities*

Hydrofluorocarbons

(1) ***Synthetic gas generating activities***, for emissions of hydrofluorocarbons, are activities of a facility that:

(a) require the use of any thing:

  (i) mentioned in paragraph 4.16 (1) (a) of the Regulations; and

  (ii) containing a refrigerant charge of more than 100 kilograms of refrigerants for each unit; and

  (iii) using a refrigerant that is a greenhouse gas with a Global Warming Potential of more than 1 000; and

(b) are attributable primarily to any one of the following ANZSIC industry classifications:

  (i) food product manufacturing (ANZSIC classification, Subdivision 11);

(ii) beverage and tobacco product manufacturing (ANZSIC classification, Subdivision 12);

(iii) retail trade (ANZSIC classification, Division G);

(iv) warehousing and storage services (ANZSIC classification, number 530);

(v) wholesale trade (ANZSIC classification Division F);

(vi) rental, hiring and real estate services (ANZSIC classification, Division L).

Sulphur hexafluoride

(2) ***Synthetic gas generating activities***, for emissions of sulphur hexafluoride, are any activities of a facility that emit sulphur hexafluoride.

4.101 Reporting threshold

For paragraph 4.22 (1) (b) of the Regulations, the threshold mentioned in column 3 of an item in the following table resulting from a provision of this Determination mentioned in column 2 of that item is a reporting threshold.

Item	Provision in Determination	Threshold
1	Subparagraph 4.100 (1) (a) (ii)	100 kilograms for each unit (hydrofluorocarbons)
2	Subsection 4.100 (2)	Any emission (sulphur hexafluoride)

4.102 Method 1

(1) Method 1 is:

$$E_{jk} = Stock_{jk} \times L_{jk}$$

where:

E_{jk} is the emissions of gas type (***j***), either hydrofluorocarbons or sulphur hexafluoride, summed over each equipment type (***k***) during a year measured in CO_2-e tonnes.

$Stock_{jk}$ is the stock of gas type (***j***), either hydrofluorocarbons or sulphur hexafluoride, contained in equipment type (***k***) during a year measured in CO_2-e tonnes.

L_{jk} is the default leakage rates for a year of gas type (***j***) mentioned in columns 3 or 4 of an item in the table in subsection (4) for the equipment type (***k***) mentioned in column 2 for that item.

(2) For the factor $\mathbf{Stock}_{jk}$, an estimation of the stock of synthetic gases contained in an equipment type must be based on the following sources:

(a) the stated capacity of the equipment according to the manufacturer's nameplate;

(b) estimates based on:

(i) the opening stock of gas in the equipment; and

(ii) transfers into the facility from additions of gas from purchases of new equipment and replenishments; and

(iii) transfers out of the facility from disposal of equipment or gas.

(3) For equipment type (***k***), the equipment are the things mentioned in subregulation 4.16 (1) of the Regulations.

(4) For subsection (1), columns 3 and 4 of an item in the following table set out default leakage rates of gas type (***j***), for either hydrofluorocarbons or sulphur hexafluoride, in relation to particular equipment types (***k***) mentioned in column 2 of the item:

Item	Equipment type (*k*)	Default annual leakage rate of gas (*j*)	
		Hydrofluorocarbons	Sulphur hexafluoride
1	Commercial air conditioning	0.09	
2	Commercial refrigeration	0.23	
3	Industrial refrigeration	0.16	
4	Gas insulated switchgear and circuit breaker applications		0.005

Chapter 5 Waste (UNFCCC Category 6)

Part 5.1 Preliminary

5.1 Outline of Chapter

This Chapter provides for UNFCCC Category 6 (waste) as follows:

(a) Part 5.2 provides for emissions released from solid waste disposal on land — UNFCCC Category 6.A;

(b) Part 5.3 provides for emissions released from wastewater handling (domestic and commercial) — UNFCCC Category 6.B.2;

(c) Part 5.4 provides for emissions released from wastewater handling (industrial) — UNFCCC Category 6.B.1;

(d) Part 5.5 provides for emissions released from waste incineration — UNFCCC Category 6.C.

Part 5.2 Emissions released from solid waste disposal on land — UNFCCC Category 6.A

Division 5.2.1 Preliminary

5.2 Application

This Part applies to UNFCCC Category 6.A — emissions released from solid waste disposal on land.

5.3 Available methods

(1) Subject to section 1.18 for estimating emissions released from the operation of a facility that is constituted by a landfill during a year:

(a) subject to paragraph (c), one of the following methods must be used for emissions of methane from the landfill (other than from flaring of methane):

(i) method 1 under section 5.4;

(ii) method 2 under section 5.15;

(iii) method 3 under section 5.18; and

(b) one of the following methods must be used for emissions for each gas type released as a result of methane flared from the operation of the landfill:

(i) method 1 under section 5.19;

(ii) method 2 under section 5.20;

(iii) method 3 under section 5.21; and

(c) method 1 under section 5.22 must be used for emissions from the biological treatment of solid waste at the landfill.

(2) Under paragraph (1) (b), the same method must be used for estimating emissions of each gas type.

(3) For incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Note There is no method 4 for paragraphs (a) and (b) and no methods 2, 3 or 4 for paragraph (1) (c). It is proposed that a method 4 will be developed in the future.

Division 5.2.2 Method 1 — emissions of methane released from landfills

5.4 Method 1 — methane released from landfills (other than from flaring of methane)

(1) For subparagraph 5.3 (1) (a) (i), method 1 is:

$$E_j = \left[CH_4^{*} - \gamma\,(Q_{cap} + Q_{flared} + Q_{tr})\right] \times (1 - OF)$$

where:

E_j is emissions of methane released by the landfill during the year .

CH_4 * is the estimated quantity of methane in landfill gas generated by the landfill during the year as determined under subsection (2) and measured in CO_2-e tonnes.

γ is the factor $6.784 \times 10^{-4} \times 21$ converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_cap is the quantity of methane in landfill gas captured for combustion from the landfill during the year and measured in cubic metres in accordance with Division 2.3.6.

Q_flared is the quantity of methane in landfill gas flared from the landfill during the year and measured in cubic metres in accordance with Division 2.3.6.

Q_tr is the quantity of methane in landfill gas transferred out of the landfill during the year and measured in cubic metres in accordance with Division 2.3.6.

OF is the oxidation factor (0.1) for near surface methane in the landfill.

(2) For subsection (1), if $\frac{Q_{cap}}{CH_{4gen}}$ is less than or equal to 0.75, then:

$$CH_4^{*} = CH_{4gen}$$

where:

CH_4gen is the quantity of methane in landfill gas generation released from the landfill during the year estimated in accordance with subsection (5) and measured in tonnes CO_2-e.

(3) For subsection (1), if $\frac{Q_{cap}}{CH_{4gen}}$ is greater than 0.75 then:

$$CH_4^{*} = \gamma Q_{cap} \times \left(\frac{1}{0.75}\right)$$

where:

γ is the factor 6.784 x 10^{-4} x 21 converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in landfill gas captured for combustion from the landfill during the year and measured in cubic metres in accordance with Division 2.3.6.

(4) For subsections (1) and (3), ***Q_{cap}*** is to be calculated in accordance with Division 2.3.6.

(5) For subsection (2), CH_{4gen} must be calculated using:

(a) the Tier 2 first order decay model (the ***Tier 2 FOD model***) in Volume 5, Chapter 3 of the 2006 IPCC Guidelines; and

(b) estimates, in accordance with sections 5.5 to 5.14, of the following:

(i) the tonnage of total solid waste received at the landfill during the year (see section 5.5);

(ii) the composition of the solid waste received at the landfill during the year (see section 5.9);

(iii) the degradable organic carbon content of the solid waste received at the landfill by waste type (see section 5.12);

(iv) the opening stock of degradable organic carbon in the solid waste at the landfill at the start of the first reporting period for the landfill (see section 5.13);

(v) methane generation constants (***k values***) for the solid waste at the landfill (see section 5.14).

5.5 Criteria for estimating tonnage of total solid waste

For subparagraph 5.4 (5) (b) (i), the tonnage of total solid waste received at the landfill during the year is to be estimated using one of the following criteria:

(a) as provided in section 5.6 (***criterion A***);

(b) as provided in section 5.7 (***criterion AAA***);

(c) as provided in section 5.8 (***criterion BBB***).

5.6 Criterion A

For paragraph 5.5 (a), criterion A is:

(a) the amount of solid waste received at the landfill during the year as evidenced by invoices; or

(b) if the amount of solid waste received at the landfill during the year is measured in accordance with State or Territory legislation applying to the landfill — that measurement.

5.7 Criterion AAA

For paragraph 5.5 (b), criterion AAA is the direct measurement of quantities of solid waste received at the landfill during the year using measuring equipment calibrated to a measurement requirement.

5.8 Criterion BBB

For paragraph 5.5 (c), criterion BBB is the estimation of solid waste received at the landfill during the year in accordance with industry estimation practices (including the use of accepted industry weighbridges) that meet the general criteria in section 1.13.

5.9 Composition of solid waste

(1) For subparagraph 5.4 (5) (b) (ii), the composition of solid waste received at the landfill during the year must be classified by waste stream in accordance with subsection 5.10 (1) and an estimate of tonnage for each waste stream must be provided in accordance with subsection 5.10 (2).

(2) For each waste stream classification there must be a further classification in accordance with section 5.11 showing the waste mix types in each waste stream, expressed as a percentage of the total tonnage of solid waste in the waste stream.

5.10 Waste streams

(1) For subsection 5.9 (1), the waste streams are:

(a) municipal solid waste stream; or

(b) commercial and industrial waste stream; or

(c) construction and demolition waste stream.

(2) For subsection 5.9 (1), the tonnage of each waste stream must be estimated:

(a) by using criterion A in section 5.6, criterion AAA in section 5.7 or criterion BBB in section 5.8 to calculate the percentage of each waste stream in relation to the total tonnage of solid waste at the landfill; or

(b) by using the percentage values in columns 3 to 10 of an item in the following table for each waste stream in column 2 for the item for the State or Territory in which the landfill is located.

Item	**Waste stream**	**NSW %**	**VIC %**	**QLD %**	**WA %**	**SA %**	**TAS %**	**ACT %**	**NT %**
1	Municipal solid waste	31	36	43	26	36	57	43	43
2	Commercial and industrial	42	24	14	17	19	33	42	14

Item	Waste stream	NSW %	VIC %	QLD %	WA %	SA %	TAS %	ACT %	NT %
3	Construction and demolition	27	40	43	57	45	10	15	43

5.11 Waste mix types

(1) For subsection 5.9 (2), the waste mix types are as follows:

(a) food;
(b) paper and paper board;
(c) textiles;
(d) garden and park;
(e) wood and wood waste;
(f) sludge;
(g) nappies;
(h) rubber and leather;
(i) concrete, metal, plastic and glass.

(2) The percentage of the total waste volume for each waste mix type mentioned in column 2 of an item in the following table must be estimated by using:

(a) sampling techniques in accordance with the general sampling criteria set out in section 5.16; or
(b) the default percentages in columns 3, 4 and 5 for the item for each waste stream.

Item	Waste mix type	Municipal waste stream %	Commercial and industrial waste stream %	Construction and demolition waste stream %
1	Food	26	6	-
2	Paper and paper board	26	55	3
3	Garden and park	10	3	2
4	Wood and wood waste	2	14	6
5	Textiles	4	2	-
6	Sludge	-	3	-
7	Nappies	6	-	-
8	Rubber and Leather	-	1	-
9	Concrete, metal, plastic and glass	26	16	89

5.12 Degradable organic carbon content

For subparagraph 5.4 (5) (b) (iii), the amount of the degradable organic carbon content of the solid waste at the landfill must be estimated by using the degradable organic carbon values in column 3 of an item in the following table for each waste mix type in column 2 for that item.

Item	Waste mix type	Degradable organic carbon value
1	Food	0.15
2	Paper and cardboard	0.40
3	Garden and green	0.20
4	Wood	0.43
5	Textiles	0.24
6	Sludge	0.05
7	Nappies	0.24
8	Rubber and Leather	0.39
9	Concrete, metal, plastic and glass	0.00

5.13 Opening stock of degradable organic carbon

For subparagraph 5.4 (5) (b) (iv), the amount of opening stock of degradable organic carbon at the landfill at the start of the first reporting period for the landfill must be estimated in accordance with the Tier 2 FOD model mentioned in subsection 5.4 (5):

(a) by using the details of the total tonnage of solid waste (broken down into waste stream and waste mix type) received at the landfill each year over the lifetime of the landfill until the start of the first reporting period for the landfill; or

(b) if the operator of a landfill is unable to comply with paragraph (a) — by using the following information in relation to the landfill:

  (i) the number of years that the landfill has been in operation;

  (ii) the estimated annual tonnage of solid waste received at the landfill over the lifetime of the landfill until the start of the first reporting period for the landfill;

  (iii) the State or Territory in which the landfill is located.

5.14 Methane generation constants — (k values)

For subparagraph 5.4 (5) (b) (v), the methane generation constants (***k values***) for solid waste at a landfill in a State or Territory mentioned in column 2 of an item in the following table are the constants set out in column 4 for a waste mix type mentioned in column 3 for the item.

Item	State/Territory	Waste mix type	k values
1	NSW	Food	0.185
		Paper and cardboard	0.06
		Garden and Green	0.10
		Wood	0.03
		Textiles	0.06
		Sludge	0.185
		Nappies	0.06
		Rubber and Leather	0.06
2	VIC, WA, SA, TAS, ACT	Food	0.06
		Paper and cardboard	0.04
		Garden and Green	0.05
		Wood	0.02
		Textiles	0.04
		Sludge	0.06
		Nappies	0.06
		Rubber and Leather	0.04
3	QLD, NT	Food	0.4
		Paper and cardboard	0.07
		Garden and Green	0.17
		Wood	0.035
		Textiles	0.07
		Sludge	0.4
		Nappies	0.07
		Rubber and Leather	0.07

Division 5.2.3 Method 2 — emissions of methane released from landfills

Subdivision 5.2.3.1 methane released from landfills

5.15 Method 2 — methane released from landfills (other than from flaring of methane)

(1) For subparagraph 5.3 (1) (a) (ii), method 2 is:

$$E_j = \left[CH_{4gen} - \gamma(Q_{cap} + Q_{flared} + Q_{tr})\right] \times (1 - OF)$$

where:

E_j is the emissions of methane released by the landfill during the year measured in CO_2-e tonnes.

CH_{4gen} is the estimated quantity of methane in landfill gas generated by the landfill during the year as calculated under subsection (2) and measured in CO_2-e tonnes.

γ is the factor $6.784 \times 10^{-4} \times 21$ converting cubic metres of methane at standard conditions measured to CO_2-e tonnes.

Q_{cap} is the quantity of methane in landfill gas captured for combustion from the landfill during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{flared} is the quantity of methane in landfill gas flared from the landfill during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{tr} is the quantity of methane in landfill gas transferred out of the landfill during the year measured in cubic metres in accordance with Division 2.3.6.

OF is the oxidation factor (0.1) for near surface methane in the landfill.

(2) For subsection (1), CH_{4gen} must be calculated in accordance with equation 5.1 in Chapter 5 of the publication entitled *IPCC 2000 Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* published by the IPCC.

(3) For the equation mentioned in subsection (2), the estimation of the methane generation constant (***k***) must be estimated from sampling and analysis of landfill gas flow rates in accordance with sections 5.16 and 5.17.

(4) Solid waste and landfill gas, in the landfill must be sampled and analysed during the year for gas flow rates and gas content in accordance with the requirements of sections 5.16 and 5.17.

(5) This method may only be used if specific information is available on the waste mix types at the landfill.

Subdivision 5.2.3.2 Sampling and analysis

5.16 General requirements for sampling under method 2

(1) A sample must be representative of the waste deposited at the landfill and the gas generated by the waste.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the sample must only be used for the landfill for which it was intended to be representative.

5.17 Standards for analysis

(1) Samples must be analysed to estimate the landfill gas flow rate at the landfill during the year and the methane concentration in the gas.

(2) The analysis of the landfill gas flow rate must be undertaken in accordance with USEPA Method 2E — *Determination of landfill gas production flow rates* (2000) or an equivalent Australian or international standard.

(3) The analysis of the methane concentration of the landfill gas must be undertaken in accordance with USEPA Method 3C — *Determination of carbon dioxide, methane, nitrogen, and oxygen from stationary sources* (1996) or an equivalent Australian or international standard.

Division 5.2.4 Method 3 — emissions of methane released from solid waste at landfills

5.18 Method 3 — methane released from solid waste at landfills (other than from flaring of methane)

(1) For subparagraph 5.3 (1) (a) (iii) and subject to subsection (2), method 3 is the same as method 2 under section 5.15.

(2) In applying method 2 under section 5.15, the solid waste at the landfill must be sampled during the year in accordance with USEPA Method 2E — *Determination of landfill gas production flow rates* (2000), or an equivalent Australian or international standard.

Division 5.2.5 Solid waste at landfills — Flaring

5.19 Method 1 — landfill gas flared

(1) For subparagraph 5.3 (b) (i), method 1 is:

$$E_{j\ \text{flared}} = Q_{\text{flared}} \times EC_i \times \frac{EF_{ij}}{1000}$$

where:

$E_{j\ flared}$ is the emissions of gas type (***j***), being methane and nitrous oxide, released from the landfill from flaring of the methane in landfill gas during the year measured in CO_2-e tonnes.

Q_{flared} is the quantity of methane in landfill gas flared during the year measured in cubic metres in accordance with Division 2.3.6.

EC_i is the energy content of methane in landfill gas in gigajoules per cubic metre (see Schedule 1).

EF_{ij} is the relevant emission factor for gas type (***j***), being methane and nitrous oxide, from the combustion of landfill gas in kilograms of CO_2-e per gigajoule (see Schedule 1).

(2) For ***Q_{flared}*** in subsection (1), the methane in landfill gas is taken to constitute 50% of the landfill gas.

5.20 Method 2 — landfill gas flared

(1) For subparagraph 5.3 (1) (b) (ii) and subject to this section, method 2 is the same as method 1 under section 5.19.

(2) In applying method 1 under section 5.19, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Subdivision 2.3.3.2 and the measurement requirements in Division 2.3.6.

5.21 Method 3 — landfill gas flared

(1) For subparagraph 5.3 (1) (b) (iii) and subject to this section, method 3 is the same as method 1 under section 5.19.

(2) In applying method 1 under section 5.19, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Division 2.3.4 and the measurement requirements in Division 2.3.6.

Division 5.2.6 Biological treatment of solid waste

5.22 Method 1 — biological treatment of solid waste at the landfill

For paragraph 5.3 (1) (c), method 1 is the Tier 1 method for measuring emissions from biological treatment of solid waste set out in Volume 5, Chapter 4, of the 2006 IPCC Guidelines.

Part 5.3 Emissions from wastewater handling (domestic and commercial) — UNFCCC Category 6.B.2

Division 5.3.1 Preliminary

5.23 Application

This Part applies to UNFCCC Category 6.B.2 — emissions released from wastewater handling (domestic and commercial).

5.24 Available methods

(1) Subject to section 1.18, for estimating emissions released from the operation of a facility that is constituted by wastewater handling (domestic and commercial) (the ***plant***) during a year:

(a) one of the following methods must be used for emissions of methane from the plant (other than from flaring of methane):

(i) method 1 under section 5.25;

(ii) method 2 under section 5.26;

(iii) method 3 under section 5.30; and

(b) one of the following methods must be used for emissions of nitrous oxide from the plant (other than from flaring of methane):

(i) method 1 under section 5.31;

(ii) method 2 under section 5.32;

(iii) method 3 under section 5.36; and

(c) one of the following methods must be used for emissions for each gas type as a result of methane flared from the plant:

(i) method 1 under section 5.37;

(ii) method 2 under section 5.38;

(iii) method 3 under section 5.39.

(2) Under paragraph (1) (c), the same method must be used for estimating emissions of each gas type.

(3) For incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Note There is no method 4 for paragraphs (1) (a), (b) and (c).

Division 5.3.2 Method 1 — methane released from wastewater handling (domestic and commercial)

5.25 Method 1 — methane released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24 (1) (a) (i), method 1 is:

$$E_j = \left[CH_4^* - \gamma(Q_{cap} + Q_{flared} + Q_{tr})\right]$$

where:

E_j is the emissions of methane released by the plant during the year measured in CO_2-e tonnes.

CH_4^* is the estimated quantity of methane in sludge biogas released by the plant during the year measured in CO_2-e tonnes as determined under subsections (2) and (3).

γ is the factor $6.784 \times 10^{-4} \times 21$ converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion for use by the plant during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{flared} is the quantity of methane in sludge biogas flared during the year by the plant measured in cubic metres in accordance with Division 2.3.6.

Q_{tr} is the quantity of methane in sludge biogas transferred out of the plant during the year measured in cubic metres in accordance with Division 2.3.6.

(2) For subsection (1), if $\frac{Q_{cap}}{CH_{4gen}}$ is less than or equal to 0.75, then:

$$CH_4^* = CH_{4gen}$$

where:

CH_{4gen} is the quantity of methane in sludge biogas produced by the plant during the year estimated in accordance with subsection (5) and measured in CO_2-e tonnes.

(3) For subsection (1), if $\frac{Q_{cap}}{CH_{4gen}}$ is greater than 0.75 then:

$$CH_4^* = \gamma Q_{cap} \times \left(\frac{1}{0.75}\right)$$

where:

γ is the factor 6.784 x 10^{-4} x 21 converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion by the plant measured in cubic metres in accordance with Division 2.3.6.

(4) For subsections (1) and (3), ***Q_{cap}*** is to be calculated in accordance with Division 2.3.6.

(5) For subsection (2):

$$CH_{4gen} = \left[(COD_{w} - COD_{sl} - COD_{eff}) \times F_{wan} \times EF_{wij}\right] + \left[(COD_{sl} - COD_{trl} - COD_{tro}) \times F_{slan} \times EF_{slij}\right]$$

where:

COD_W is the factor worked out as follows:

$$COD_{w} = P \times DC_{w}$$

where:

P is the population served by the operation of the plant during the year and measured in numbers of persons.

DC_w is the quantity in kilograms of COD per capita of wastewater for a year using a default of 0.0585 tonnes per person.

CH_{4gen} is the methane generated from commercial wastewater and sludge treatment by the plant during the year measured in CO_2-e tonnes.

COD_w is the chemical oxygen demand (***COD***) in wastewater entering the plant during the year measured in tonnes.

COD_{sl} is the quantity of COD removed as sludge from wastewater and treated in the plant measured in tonnes of COD.

COD_{eff} is the quantity of COD in effluent leaving the plant during the year measured in tonnes.

F_{wan} is the fraction of COD anaerobically treated by the plant during the year.

Note IPCC default fractions for various types of treatment are:

- managed aerobic treatment: 0
- unmanaged aerobic treatment: 0.3
- anaerobic digester/reactor: 0.8
- shallow anaerobic lagoon (<2 metres): 0.2
- deep anaerobic lagoon (>2 metres): 0.8

EF_{wij} is the default methane emission factor for wastewater with a value of 5.3 CO_2-e tonnes per tonne COD.

COD_{trl} is the quantity of COD in sludge transferred out of the plant and removed to landfill measured in tonnes of COD.

COD_{tro} is the quantity of COD in sludge transferred out of the plant and removed to a site other than landfill measured in tonnes of COD.

F_{slan} is the fraction of COD in sludge anaerobically treated by the plant during the year.

Note IPCC default fractions for various types of treatment are:

- managed aerobic treatment: 0
- unmanaged aerobic treatment: 0.3
- anaerobic digester/reactor: 0.8
- shallow anaerobic lagoon (<2 metres): 0.2
- deep anaerobic lagoon (>2 metres): 0.8

EF_{slij} is the default methane emission factor for sludge with a value of 5.3 CO_2-e tonnes per tonne COD (sludge).

(6) For subsection (5), an operator of the plant must choose a treatment for F_{wan} and estimate the quantity of COD removed from the wastewater as sludge (COD_{sl}).

(7) For subsection (6), the quantity of COD removed as sludge may be estimated using the following equation:

$$COD_{sl} = VS_{sl} \times 1.48$$

where:

VS_{sl} is the estimated volatile solids in the sludge.

Division 5.3.3 Method 2 — methane released from wastewater handling (domestic and commercial)

5.26 Method 2 — methane released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24 (1) (a) (ii) and subject to this section, method 2 is the same as method 1 under section 5.25.

(2) In applying method 1 under section 5.25, the ***COD*** mentioned in subsection 5.25 (5) must be estimated from wastewater entering the plant and must be calculated by using:

(a) facility operating data that measures the volumetric influent and effluent rates and the influent and effluent rates of COD concentrations; or

(b) if data is available on the biochemical oxygen demand (***BOD***) in the wastewater — that data converted to COD in accordance with the following formula:

$$\text{COD} = 2.6 \times \text{BOD}_5$$

(3) Wastewater used for the purposes of subsection (2), must be sampled and analysed for COD in accordance with the requirements in sections 5.27, 5.28 and 5.29.

5.27 General requirements for sampling under method 2

(1) A sample must be representative of the wastewater and the COD concentrations at the plant.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias may be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the sample must only be used for the plant for which it was intended to be representative.

5.28 Standards for analysis

(1) Samples of wastewater must be analysed for COD in accordance with:

(a) ISO 6060:1989; or

(b) sections 5220B, 5220C or 5220D of APHA (1995); or

(c) an equivalent Australian or international standard.

(2) Samples of wastewater must be analysed for BOD in accordance with:

(a) AS 4351.5—1996; or

(b) section 5210B of APHA (1995); or

(c) an equivalent Australian or international standard.

5.29 Frequency of sampling and analysis

Wastewater must be sampled and analysed on at least a monthly basis.

Division 5.3.4 Method 3 — methane released from wastewater handling (domestic and commercial)

5.30 Method 3 — methane released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24 (a) (iii) and subject to subsection (2), method 3 is the same as method 2 under section 5.26.

(2) In applying method 2 under section 5.26, the wastewater must be sampled in accordance with AS/NZS 5667.10:1998 or an equivalent Australian or international standard.

Division 5.3.5 Method 1 — emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.31 Method 1 — nitrous oxide released from wastewater handling (domestic and commercial)

(1) For paragraph 5.24 (1) (b), method 1 is:

$$E_j = (N_{in} - N_{trl} - N_{tro} - N_{out}) \times EF_{secij} + N_{out} \times EF_{disij}$$

where:

E_j is the emissions of nitrous oxide released from human sewage treated by the plant during the year measured in tonnes of nitrous oxide and expressed in CO_2-e tonnes.

N_{in} is the quantity of nitrogen entering the plant during the year measured in tonnes of nitrogen, worked out as follows:

$$N_{in} = \text{Protein} \times \text{Frac}_{Pr} \times P$$

where:

Protein is the annual per capita protein intake in tonnes per person during the year of the population served by the plant.

$Frac_{Pr}$ is the fraction of nitrogen in protein.

P is the population serviced by the plant during the year.

N_{trl} is the quantity of nitrogen in sludge transferred out of the plant and removed to landfill during the year measured in tonnes of nitrogen.

N_{tro} is the quantity of nitrogen in sludge transferred out of the plant and removed to a site other than landfill during the year measured in tonnes of nitrogen.

N_{out} is the quantity of nitrogen leaving the plant in effluent during the year measured in tonnes of nitrogen.

EF_{secij} is the emission factor for wastewater treatment.

EF_{disij} is the emission factor for nitrogen discharge differentiated by the discharge environment.

(2) For EF_{disij} in subsection (1), an emission factor of 4.9 tonnes of nitrous oxide measured in CO_2-e per tonne of nitrogen produced may be used.

(3) For EF_{secij} in subsection (1), an emission factor of 4.9 tonnes of nitrous oxide measured CO_2-e per tonne of nitrogen produced may be used.

(4) For $Frac_{Pr}$ in subsection (1), a factor of 0.16 tonnes of nitrogen per tonne of protein may be used.

(5) For ***Protein*** in subsection (1), an annual per capita protein intake of 0.036 tonnes per year may be used.

Division 5.3.6 Method 2 — emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.32 Method 2 — nitrous oxide released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24 (1) (b) (ii) and subject to this section, method 2 is the same as method 1 under section 5.31.

(2) In applying method 1 under section 5.31, nitrogen must be calculated by using facility operating data that measures the volumetric influent and effluent rates and the influent and effluent rates of nitrogen concentrations.

(3) Wastewater used for the purposes of subsection (2), must be sampled and analysed for nitrogen in accordance with the requirements in sections 5.33, 5.34 and 5.35.

5.33 General requirements for sampling under method 2

(1) A sample must be representative of the wastewater and the nitrogen concentrations at the plant.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the sample must only be used for the plant for which it was intended to be representative.

5.34 Standards for analysis

(1) Samples of wastewater must be analysed for nitrogen in accordance with:
- (a) ISO 11905-1:1997; or
- (b) sections 4500-N_{org} B, 4500-N_{org} C or 4500-N_{org} D of APHA (1995); or
- (c) an equivalent Australian or international standard.

(2) Samples of sludge must be analysed for nitrogen in accordance with:
- (a) EN 13342:2000; or
- (b) section 4500-N_{org} B of APHA (1995); or
- (c) an equivalent Australian or international standard.

5.35 Frequency of sampling and analysis

Wastewater must be sampled and analysed on at least a monthly basis.

Division 5.3.7 Method 3 — emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.36 Method 3 — nitrous oxide released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24 (1) (b) (iii) and subject to subsection (2), method 3 is the same as method 2 under section 5.32.

(2) In applying method 2 under section 5.32, the wastewater must be sampled in accordance with AS/NZS 5667.10:1998 or an equivalent Australian or international standard.

(3) In applying method 2 under section 5.32, the sludge must be sampled in accordance with ISO 5667-13:1997 or an equivalent Australian or international standard.

Division 5.3.8 Wastewater handling (domestic and commercial) — Flaring

5.37 Method 1 — Flaring of methane in sludge biogas from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24 (1) (c) (i), method 1 is:

$$E_{j\ \text{flared}} = Q_{\text{flared}} \times EC_i \times \frac{EF_{ij}}{1000}$$

where

$E_{j\,flared}$ is the emissions of gas type (***j***) released from the plant from flaring of the methane in sludge biogas from the plant during the year measured in CO_2-e tonnes.

Q_{flared} is the quantity of methane in sludge biogas flared from the plant during the year measured in cubic metres in accordance with Division 2.3.6.

EC_i is the energy content of methane in sludge biogas in gigajoules per cubic metre (see Schedule 1).

EF_{ij} is the relevant emission factor for gas type (***j***) for methane in sludge biogas measured in CO_2-e per gigajoule (see Schedule 1).

(2) For ***Q_{flared}*** in subsection (1), the methane in sludge biogas is taken to constitute 70% of the sludge biogas.

5.38 Method 2 — flaring of methane in sludge biogas

(1) For subparagraph 5.24 (1) (c) (ii) and subject to this section, method 2 is the same as method 1 under section 5.37.

(2) In applying method 1 under section 5.37, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Subdivision 2.3.3.2 and the measuring requirements in Division 2.3.6.

5.39 Method 3 — flaring of methane in sludge biogas

(1) For subparagraph 5.24 (1) (c) (iii) and subject to this section, method 3 is the same as method 1 under section 5.37.

(2) In applying method 1 under section 5.37, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Division 2.3.4 and the measuring requirements in Division 2.3.6.

Part 5.4 Emissions released from wastewater handling (industrial) — UNFCCC Category 6.B.1

Division 5.4.1 Preliminary

5.40 Application

This Part applies to UNFCCC Category 6.B.1 — emissions released from wastewater handling (industrial).

5.41 Available methods

(1) Subject to section 1.18 one of the following methods must be used for estimating emissions of methane released from the operation of a facility (other than by flaring of landfill gas containing methane) that is constituted by wastewater handling (industrial) (the ***plant)*** during a year:

(a) method 1 under section 5.42;
(b) method 2 under section 5.43;
(c) method 3 under section 5.47.

(2) Subject to section 1.18, one of the following methods must also be used for estimating emissions of each gas type released as a result of methane in sludge biogas flared from the operation of the plant during a year:

(a) method 1 under section 5.48;
(b) method 2 under section 5.49;
(c) method 3 under section 5.50.

(3) Under subsection (2), the same method must be used for estimating emissions of each gas type.

(4) For incidental emission source streams another method may be used that is consistent with the principles in section 1.13.

Note There is no method 4 for subsection (1) or (2).

Division 5.4.2 Method 1 — methane released from wastewater handling (industrial)

5.42 Method 1 — methane released from wastewater handling (industrial)

(1) For paragraph 5.41 (1) (a), method 1 is:

$$E_j = \left[CH_4^* - \gamma(Q_{cap} + Q_{flared} + Q_{tr})\right]$$

where:

E_j is the emissions of methane released from the plant during the year measured in CO_2-e tonnes.

CH_4^* is the estimated quantity of methane in sludge biogas generated by the plant during the year measured in CO_2-e tonnes as determined under subsections (2) and (3).

γ is the factor $6.784 \times 10^{-4} \times 21$ converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion for the plant during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{flared} is the quantity of methane in sludge biogas flared by the plant during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{tr} is the quantity of methane in sludge biogas transferred out of the plant during the year measured in cubic metres in accordance with Division 2.3.6.

(2) For subsection (1), if $\frac{Q_{cap}}{CH_{4gen}}$ is less than or equal to 0.75, then:

$$CH_4^* = CH_{4gen}$$

where:

CH_{4gen} is the quantity of methane in sludge biogas generation for the plant during the year estimated in accordance with subsection (5) and measured in CO_2-e tonnes.

(3) For subsection (1), if $\frac{Q_{cap}}{CH_{4gen}}$ is greater than 0.75 then:

$$CH_4^* = \gamma Q_{cap} \times \left(\frac{1}{0.75}\right)$$

where:

γ is the factor 6.784 x 10^{-4} × 21 converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion for the operation of the plant measured in cubic metres.

(4) For subsections (1) and (3), ***Q_{cap}*** is to be calculated in accordance with Division 2.3.6.

(5) For subsection (2) the factor ***CH_{4gen}*** is estimated as follows:

$$CH_{4gen} = \left[\left(\Sigma_{w,i} COD_{wi} - COD_{sl}\right) \times \left(F_{wan} \times EF_{w\,ij}\right) \right] + \left[\left(COD_{sl} - COD_{trl} - COD_{tro}\right) \times F_{slan} \times EF_{slij} \right]$$

where:

$\Sigma_{w,i}$ is the total ***$COD_{w,i}$*** of wastewater entering the plant.

$COD_{w,i}$ is the COD in wastewater entering the plant related to the production by the plant of any commodity mentioned in column 2 of the table in subsection (8) during the year measured in tonnes of COD, worked out as follows:

$$COD_{w,i} = Prod_i \times W_{gen,i} \times \frac{COD_{con,i}}{1\,000}$$

where:

$Prod_i$ is the total production by the plant of any commodity mentioned in column 2 of the table in subsection (8) during the year measured in tonnes.

$W_{gen,i}$ is the wastewater generation rate from the production of any commodity mentioned in column 2 of the table in subsection (8) produced during the year and measured in cubic metres or kilolitres per tonne of commodity.

$COD_{con,i}$ is the COD concentration in kilograms of COD per cubic metre of wastewater entering the plant during the year from the production of any commodity mentioned in column 2 of the table in subsection (8).

COD_{sl} is the quantity of COD removed as sludge from wastewater during the year measured in tonnes of COD**,** worked out as follows:

$$COD_{sl} = COD_{w,i} \times F_{sl}$$

where:

$\boldsymbol{COD_{w,i}}$ is the COD in wastewater entering the plant used in the production of any commodity mentioned in column 2 of the table in subsection (8) during the year measured in tonnes of COD.

$\boldsymbol{F_{sl}}$ is the fraction of COD removed from wastewater as sludge by the plant during the year.

$\boldsymbol{F_{wan}}$ is the fraction of COD in wastewater anaerobically treated by the plant during the year.

$\boldsymbol{EF_{w\,ij}}$ is the methane emission factor for industrial wastewater.

$\boldsymbol{COD_{trl}}$ is the quantity of COD in sludge transferred out of the plant and removed to landfill during the year measured in tonnes of COD.

$\boldsymbol{COD_{tro}}$ is the quantity of COD in sludge transferred out of the plant and removed to a site other than landfill during the year measured in tonnes of COD.

$\boldsymbol{F_{slan}}$ is the fraction of COD in sludge anaerobically treated by the plant during the year.

$\boldsymbol{EF_{sl\,ij}}$ is the methane emission factor for the treatment of sludge by the plant.

(6) For $\boldsymbol{EF_{wij}}$ in subsection (5), an emission factor of 5.3 CO_2-e tonnes per tonne of COD may be used.

(7) For $\boldsymbol{EF_{slij}}$ in subsection (5), a methane emission factor of 5.3 CO_2-e tonnes per tonne of COD may be used.

(8) For subsection (5), COD must be estimated for a commodity set out in column 2 of an item in the following table:

(a) by using the default values for $\boldsymbol{W_{gen,i}}$, $\boldsymbol{COD_{con,i}}$ and $\boldsymbol{F_{wan}}$ set out in columns 3, 4 and 5 for that item; or

(b) in accordance with industry practice relevant to the measurement of the quantity of wastewater.

Item	Commodity	$W_{gen,i}$, default value	$COD_{con,i}$ default value	F_{wan} default value
1	Dairy	5.7	0.9	0.4
2	Pulp and Paper	26.7	0.4	0.0
3	Meat and Poultry	13.7	6.1	0.4
4	Organic chemicals	67.0	3.0	0.1
5	Sugar	0.4	3.8	0.3

Item	Commodity	$W_{gen,i}$, default value	$COD_{con,i}$ default value	F_{wan} default value
6	Beer	5.3	6.0	0.5
7	Wine	23.0	1.5	0.0
8	Fruit	20.0	0.2	1.0
9	Vegetables	20.0	0.2	1.0

Division 5.4.3 Method 2 — methane released from wastewater handling (industrial)

5.43 Method 2 — methane released from wastewater handling (industrial)

(1) For paragraph 5.41 (1) (b) and subject to this section, method 2 for wastewater handling (industrial) is the same as method 1 under section 5.42.

(2) In applying method 1 under section 5.42, the COD mentioned in subsection 5.42 (5) must be estimated from wastewater entering the plant and must be calculated by using:

(a) facility operating data that measures the volumetric influent rate and the influent rate of COD concentrations; or

(b) if data is available on the biochemical oxygen demand (***BOD***) in the wastewater — that data converted to COD in accordance with the following formula:

$$\mathrm{COD} = 2.6 \times \mathrm{BOD}_5$$

(3) Wastewater used for the purposes of subsection (2), must be sampled and analysed for COD in accordance with the requirements is sections 5.44, 5.45 and 5.46.

5.44 General requirements for sampling under method 2

(1) A sample must be representative of the wastewater and the COD concentrations at the plant.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the sample must only be used for the plant for which it was intended to be representative.

5.45 Standards for analysis

(1) Samples of wastewater must be analysed for COD in accordance with:

(a) ISO 6060:1989; or

(b) sections 5220B, 5220C or 5220D of APHA (1995); or

(c) an equivalent Australian or international standard.

(2) Samples of wastewater must be analysed for BOD in accordance with:

(a) AS 4351.5—1996; or

(b) section 5210B of APHA (1995); or

(c) an equivalent Australian or international standard.

5.46 Frequency of sampling and analysis

Wastewater must be sampled and analysed on at least a monthly basis.

Division 5.4.4 Method 3 — methane released from wastewater handling (industrial)

5.47 Method 3 — methane released from wastewater handling (industrial)

(1) For paragraph 5.41 (1) (c) and subject to subsection (2), method 3 is the same as method 2 under section 5.43.

(2) In applying method 2 under section 5.43, the wastewater must be sampled in accordance with AS/NZS 5667.10:1998 or an equivalent Australian or international standard.

Division 5.4.5 Wastewater handling (industrial) — Flaring of methane in sludge biogas

5.48 Method 1 — flaring of methane in sludge biogas

(1) For paragraph 5.41 (2) (a), method 1 is:

$$E_{j\ \mathrm{flared}} = Q_{\mathrm{flared}} \times EC_i \times \frac{EF_{ij}}{1\ 000}$$

where:

$E_{j\ \mathrm{flared}}$ is the emissions of gas type (***j***) released from flaring of the methane in sludge biogas by the plant during the year measured in CO_2-e tonnes.

Q_{flared} is the quantity of methane in sludge biogas flared by the plant during the year measured in cubic metres in accordance with Division 2.3.6.

EC_i is the energy content of methane in sludge biogas measured in gigajoules per cubic metre (see Schedule 1).

EF_{ij} is the relevant emission factor for gas type (***j***) for methane in sludge biogas in CO_2-e tonnes per gigajoule (see Schedule 1).

(2) For Q_{flared} in subsection (1), the methane in sludge biogas is taken to constitute 70% of the sludge biogas.

5.49 Method 2 — flaring of methane in sludge biogas

(1) For paragraph 5.41 (2) (b) and subject to this section, method 2 is the same as method 1 under section 5.48.

(2) In applying method 1 under section 5.48, Q_{flared} must be determined in accordance with the sampling and analysis requirements in Subdivision 2.3.3.2 and the measuring requirements in Division 2.3.6.

5.50 Method 3 — flaring of methane in sludge biogas

(1) For paragraph 5.41 (2) (c) and subject to this section, method 3 is the same as method 1 under section 5.48.

(2) In applying method 1 under section 5.48, Q_{flared} must be determined in accordance with the sampling and analysis requirements in Division 2.3.4 and the measuring requirements in Division 2.3.6.

Part 5.5 Emissions released from waste incineration — UNFCCC Category 6.C

5.51 Application

This Part applies to UNFCCC Category 6.C — emissions released from waste incineration.

5.52 Available methods — emissions of carbon dioxide from waste incineration

Subject to section 1.18 method 1 under section 5.53 must be used for estimating emissions of carbon dioxide released from the operation of a facility that is constituted by waste incineration (the ***plant***).

Note There is no method 2, 3 or 4 for this section.

5.53 Method 1 — emissions of carbon dioxide released from waste incineration

(1) Method 1 is:

$$E_i = Q_i \times CC_i \times FCC_i \times OF_i \times 3.664$$

where:

E_i is the emissions of carbon dioxide released from the incineration of waste type (***i***) by the plant during the year measured in CO_2-e tonnes.

Q_i is the quantity of waste type (***i***) incinerated by the plant during the year measured in tonnes of wet weight value in accordance with Division 2.3.6.

CC_i is the carbon content of waste type (***i***).

FCC_i is the proportion of carbon in waste type (***i***) that is of fossil origin.

OF_i is the oxidation factor for waste type (***i***).

(2) If waste materials other than clinical wastes have been incinerated by the plant, appropriate values for the carbon content of the waste material incinerated must be derived from Schedule 1.

(3) For CC_i in subsection (1), the IPCC default of 0.25 for clinical waste may be used.

(4) For FCC_i in subsection (1), the IPCC default of 0.40 may be used.

(5) For OF_i in subsection (1), the IPCC default of 1.00 may be used.

Chapter 6 Energy

Part 6.1 Production

6.1 Purpose

The purpose of this Part is to provide for the estimation of the energy content of energy produced from the operation of a facility during a year.

Note 1 Energy produced from the operation of a facility is dealt with in regulation 2.23 of the Regulations.

Note 2 Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and in regulation 2.03 of the Regulations.

6.2 Quantity of energy produced

(1) The quantity of an energy produced from the operation of the facility during the year must be estimated:

- (a) if the energy is a solid or gaseous fuel — in accordance with industry practice; or
- (b) if the energy is a liquid fuel — by either of the following:
  - (i) using bulk filling meters corrected to 15° celsius;
  - (ii) by the physical measurement of the fuel corrected to its notional volumetric equivalent at a temperature of 15° Celsius; or
- (c) if the energy is electricity produced for use in the operation of the facility — as the difference between:
  - (i) the amount of electricity produced by the electricity generating unit for the facility as measured at the unit's terminals; and
  - (ii) the sum of the amounts of electricity supplied to an electricity transmission or distribution network measured at the connection point for the network in accordance with either of the measurement requirements specified in subsection (3) and the amount of electricity supplied for use outside the network that is not supplied to the network; or
- (d) if the energy is electricity produced for use outside the operation of the facility — as the sum of the following:
  - (i) the amount of electricity supplied to an electricity transmission or distribution network measured at the connection point to the network in accordance with either of the measurement requirements specified in subsection (3);

(ii) the amount of electricity supplied for use outside an electricity transmission or distribution network that is not supplied to the network; or

(e) if the energy is electricity supplied to an electricity transmission or distribution network — as the amount of electricity supplied to the network measured at the connection point for the network in accordance with either of the measurement requirements specified in subsection (3).

Note Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulation 2.03 of the Regulations.

(2) For subsection (1), if the fuel is coal, its quantity must be estimated in the form of saleable coal on a washed basis.

(3) For paragraphs (1) (c), (d) and (e), the measurement requirements are as follows:

(a) Chapter 7 of the *National Electricity Rules* made under the National Electricity Law set out in the *National Electricity (South Australia) Act 1996*;

(b) metering requirements applicable to the region in which the facility is located.

6.3 Energy content of fuel produced

(1) The energy content of a kind of energy (***fuel***) produced from the operation of the facility during the year is to be worked out as follows:

$$Z_i = Q_i \times EC_i$$

where:

$\boldsymbol{Z_i}$ is the energy content of fuel type (***i***) produced during the year and measured in gigajoules.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) produced during the year.

$\boldsymbol{EC_i}$ is the energy content factor of fuel type (***i***), measured as energy content according to the fuel type measured in gigajoules:

(a) as mentioned in Schedule 1; or

(b) in accordance with Divisions 2.2.3 and 2.2.4 (solid fuels), Divisions 2.3.3 and 2.3.4 (gaseous fuels) or Divisions 2.4.3 and 2.4.4 (liquid fuels); or

(c) for electricity measured in kilowatt hours, $\boldsymbol{EC_i}$ is equal to 0.0036; or

(d) for fuels measured in gigajoules, $\boldsymbol{EC_i}$ is equal to 1.

Note Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulation 2.03 of the Regulations.

(2) The amount of electricity produced from the operation of the facility during the year must be evidenced by invoices, contractual arrangements or industry metering records.

Part 6.2 Consumption

6.4 Purpose

The purpose of this Part is to provide for the estimation of the energy content of energy consumed from the operation of a facility during a year.

Note 1 Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulations 2.03 of the Regulations.

Note 2 Energy consumed from the operation of a facility is dealt with in regulation 2.23 of the Regulations.

6.5 Energy content of energy consumed

(1) The energy content of a kind of energy (***fuel***) consumed from the operation of the facility during the year is to be worked out as follows:

$$Z_i = Q_i \times EC_i$$

where:

Zi is the energy content of fuel type (***i***) consumed during the year and measured in gigajoules.

Qi is the quantity of fuel type (***i***) consumed during the year estimated in accordance with:

(a) Divisions 2.2.5 (solid fuels), 2.3.6 (gaseous fuels) and 2.4.6 (liquid fuels); or

(b) subsection (2) for electricity.

ECi is the energy content factor of fuel type (***i***), measured as energy content according to fuel type (***i***) expressed in gigajoules:

(a) as mentioned in Schedule 1; or

(b) in accordance with Divisions 2.2.3 and 2.2.4 (solid fuels), Divisions 2.3.3 and 2.3.4 (gaseous fuels) or Divisions 2.4.3 and 2.4.4 (liquid fuels); or

(c) for electricity measured in kilowatt hours, ***ECi*** is equal to 0.0036; or

(d) for fuels measured in gigajoules, ***ECi*** is equal to 1.

Note Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulation 2.03 of the Regulations.

(2) The amount of electricity consumed from the operation of the facility during the year must be evidenced by invoices, contractual arrangements or industry metering records.

Chapter 7 Scope 2 emissions

7.1 Outline of Chapter

This Chapter specifies a method of determining scope 2 emissions from the consumption of electricity purchased from an electricity grid.

Note Scope 2 emissions result from activities that generate electricity, heating, cooling or steam that is consumed by a facility but that do not form part of the facility (see paragraph 2.23 (2) (b) of the Regulations).

7.2 Method 1 — purchase of electricity from network

(1) The following method must be used for estimating scope 2 emissions released from electricity purchased from an electricity grid and consumed from the operation of a facility during a year:

$$Y = Q \times \frac{EF}{1\,000}$$

where:

Y is the scope 2 emissions measured in CO_2-e tonnes.

Q, subject to subsection (2), is the quantity of electricity purchased from the electricity grid during the year and consumed from the operation of the facility measured in kilowatt hours.

EF is the scope 2 emission factor, in kilograms of CO_2-e emissions per kilowatt hour, for the State, Territory or electricity grid in which the consumption occurs as mentioned in Part 6 of Schedule 1.

Note There is no other method for this section.

(2) For a facility the operation of which is constituted by an electricity transmission network or distribution network, ***Q*** is the quantity of electricity losses for that transmission network or distribution network during the year.

(3) For ***Q***, if the electricity purchased is measured in gigajoules, the quantity of kilowatt hours must be calculated by dividing the amount of gigajoules by 0.0036.

Chapter 8 Assessment of uncertainty

Part 8.1 Preliminary

8.1 Outline of Chapter

This Chapter specifies the way in which uncertainty is to be assessed in working out estimates of emissions released from the operation of a facility.

Part 8.2 Rules for assessment of uncertainty

8.2 Purpose of Part

This Part sets out rules that apply in the assessment of uncertainty of emissions.

8.3 Rules about assessment of uncertainty

(1) Subject to this section, the uncertainty of emissions estimates is to be assessed in accordance with the *GHG Protocol guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty* (September 2003) v1.0 (the ***protocol***) issued by the World Resources Institute and the World Business Council on Sustainable Development.

(2) Estimates need only provide for statistical uncertainty in accordance with the protocol.

(3) Uncertainty must be assessed so that the range for an emissions estimate encompasses the actual amount of the emissions with 95% confidence.

8.4 Uncertainty to be assessed having regard to all facilities

(1) Uncertainty of estimates of the emissions released from the operation of a facility under the operational control of a registered corporation must be assessed in accordance with the protocol having regard to all of the facilities under the operational control of the corporation.

(2) However, if the corporation is part of a group, uncertainty of estimates of the emissions released from the operation of facilities under the operational control of the corporation must be assessed in accordance with the protocol having regard to all of the facilities under the operational control of the members of the group.

Part 8.3 Uncertainty levels for use with method 1

8.5 Purpose of Part

This Part sets out uncertainty levels that must be used if method 1 for a source is chosen to estimate emissions released from the source.

8.6 Assessment of uncertainty using method 1 — carbon dioxide emissions from combustion of fuels

In assessing uncertainty of the estimates of carbon dioxide emissions estimated using method 1 for a source that involves the combustion of a fuel specified in column 2 of an item of the following table, column 3 for that item sets out the uncertainty levels for the carbon dioxide emission factor in the method.

Item	Fuel combusted	Uncertainty level (%)
1	Diesel oil	2
2	Solvents if mineral turpentine or white spirits	2
3	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 8 and 9; and (b) the petroleum based products mentioned in items 1 and 2, 4 to 7, 10 to 12, 20 to 22, and 25, 34, 35 and 44.	2
4	Liquefied aromatic hydrocarbons	2
5	Kerosene (other than for use as fuel in an aircraft)	2
6	Heating oil	2
7	Fuel oil	2
8	Petroleum based greases	2
9	Petroleum based oils (other than petroleum based oils used as fuel)	2
10	Crude oil including crude oil condensates	3
11	Liquid petroleum gas	3
12	Kerosene for use as fuel in an aircraft	3
13	Natural gas if distributed in a pipeline	4
14	Coal seam methane that is captured for combustion	4
15	Coal mine waste gas that is captured for combustion	4

Item	Fuel combusted	Uncertainty level (%)
16	Compressed natural gas	4
17	Unprocessed natural gas	4
18	Town gas	4
19	Liquefied natural gas	4
20	Gasoline for use as fuel in an aircraft	4
21	Gasoline (other than for use as fuel in an aircraft)	4
22	Naptha	5
23	Black coal (other than used to produce coke)	5
24	Coking coal	7
25	Other natural gas liquids	9
26	Ethane	10
27	Coke oven coke	11
28	Brown coal briquettes	11
29	Brown coal	12
30	Sulphite lyes	15
31	Primary solid biomass fuels other than those mentioned in items 30, 32, 33 and 36 to 38	16
32	Biomass municipal and industrial materials, if recycled and combusted to produce heat or energy	16
33	Bagasse	16
34	Petroleum coke	17
35	Refinery coke	17
36	Dry wood	17
37	Green and air dried wood	17
38	Charcoal	17
40	Coal tar	17
41	Blast furnace gas	17
42	Ethanol for use as a fuel in an internal combustion engine	17
43	Biodiesel~~s~~	17
44	Refinery gas and liquids	18
45	Landfill biogas that is captured for combustion	18
46	Sludge biogas that is captured for combustion	18
47	Coke oven gas	19

Item	Fuel combusted	Uncertainty level (%)
48	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	26
49	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	26

Note The uncertainty estimates are from the 2006 IPCC Guidelines, volume 2.

8.7 Assessment of uncertainty using method 1 — methane and nitrous oxide emissions from combustion of fuels

In assessing uncertainty of the estimates of methane and nitrous oxide emissions released from fuel combustion using method 1, the uncertainty level is 50%.

8.8 Assessment of uncertainty using method 1 — fugitive emissions

In assessing uncertainty of the estimates of fugitive emissions estimated using method 1 for activities mentioned in column 2 of an item of the following table, column 3 for that item sets out the uncertainty levels for the emission factor mentioned in the method.

Item	Activities	Uncertainty level (%)
1	Gas flared from natural gas production and processing[1]	25
2	Open cut coal mines[2]	50
3	Underground coal mines[3]	50
4	Decommissioned mines[4]	50
5	Oil and gas exploration, production, processing, transmission[5]	50

Note The uncertainty estimates are from the 2006 IPCC Guidelines, volume 2.

[1] IPCC (2006, page 4.49).

[2] IPCC (2006, page 4.20).

[3] IPCC (2006, page 4.15).

[4] IPCC (2006, page 4.29).

[5] IPCC (2006, page 4.49).

8.9 Assessment of uncertainty using method 1 — emissions from industrial processes

In assessing uncertainty of the estimates of emissions estimated using method 1 for industrial process activities mentioned in column 2 of an item of the following table, column 3 for that item sets out the uncertainty levels for the emission factor mentioned in the method.

Item	**Activities**	**Uncertainty level (%)**
1	Soda ash use and other uses of carbonates[1]	5
2	Production of cement clinker[2]	6
3	Production of lime[3]	6
4	Consumption of hydrofluorocarbons and sulphur hexafluoride gases[4]	30
5	Nitric acid production[5]	40
6	Perfluorocarbons from aluminium production[6]	–99/+380

Note The uncertainty estimates are from the 2006 IPCC Guidelines, volume 3.

[1] IPCC (2006, page 2.39).

[2] IPCC (2006, page 2.17).

[3] IPCC (2006, page 2.25).

[4] IPCC (2006, page 8.21).

[5] IPCC (2006, page 3.23).

[6] IPCC (2006, page 4.54).

Schedule 1 Energy content factors and emission factors

(section 2.4, subsections 2.5 (1), 2.6 (1), 2.20 (1) and 2.21 (1), paragraph 2.38 (2) (b), section 2.41, subsections 2.42 (1) and 2.48 (2), section 3.14, subsections 4.31 (1), 4.42 (1) and 4.55 (1), section 4.60 and subsections 4.71 (2), 4.94 (2), 5.19 (1), 5.37 (1), 5.48 (1), 5.53 (2), 6.3 (1), 6.5 (1) and 7.2 (1))

Note Under the 2006 IPCC Guidelines, the emission factor for CO_2 released from combustion of biogenic carbon fuels is zero.

Part 1 Fuel combustion — solid fuels and certain coal-based products

Item	**Fuel combusted**	**Energy content factor GJ/t**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
1	Black coal (other than that used to produce coke)	27.0	88.2	0.03	0.2
2	Brown coal	10.2	92.7	0.01	0.4
3	Coking coal	30.0	90.0	0.02	0.2
4	Brown coal briquettes	22.1	93.3	0.06	0.3
5	Coke oven coke	27.0	104.9	0.03	0.2
6	Coal tar	37.5	81.0	0.02	0.2
7	Solid fossil fuels other than those mentioned in items 1 to 5	22.1	93.3	0.06	0.3
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	26.3	79.9	0.02	0.2
9	Non-biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	10.5	85.4	0.6	1.2
10	Dry wood	16.2	0.0	0.08	1.2
11	Green and air dried wood	10.4	0.0	0.08	1.2
12	Sulphite lyes	12.4	0.0	0.06	0.6
13	Bagasse	9.6	0.0	0.2	1.3

Item	Fuel combusted	Energy content factor GJ/t	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	12.2	0.0	0.6	1.2
15	Charcoal	31.1	0.0	4.0	1.2
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	12.2	0.0	0.6	1.2

Note Energy content and emission factors for coal products are measured on an as fired basis. Black coal represents coal for uses other than electricity and coking. The energy content for black coal and coking coal (metallurgical coal) is on a washed basis.

Part 2 Fuel combustion — gaseous fuels

Item	Fuel combusted	Energy content factor (GJ/m^3 unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
17	Natural gas distributed in a pipeline	39.3×10^{-3}	51.2	0.1	0.03
18	Coal seam methane that is captured for combustion	37.7×10^{-3}	51.1	0.2	0.03
19	Coal mine waste gas that is captured for combustion	37.7×10^{-3}	51.6	5.0	0.03
20	Compressed natural gas	39.3×10^{-3}	51.2	0.1	0.03
21	Unprocessed natural gas	39.3×10^{-3}	51.2	0.1	0.03
22	Ethane	57.5×10^{-3}	56.2	0.02	0.03
23	Coke oven gas	18.1×10^{-3}	36.8	0.03	0.06
24	Blast furnace gas	4.0×10^{-3}	232.8	0.02	0.03
25	Town gas	39.0×10^{-3}	59.9	0.03	0.03
26	Liquefied natural gas	25.3 GJ/kL	51.2	0.1	0.03
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	39.3×10^{-3}	51.2	0.1	0.03

Item	Fuel combusted	Energy content factor (GJ/m^3 unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
28	Landfill biogas that is captured for combustion (methane only)	37.7×10^{-3}	0.0	4.8	0.03
29	Sludge biogas that is captured for combustion (methane only)	37.7×10^{-3}	0.0	4.8	0.03
30	A biogas that is captured for combustion, other than those mentioned in items 28 and 29 (methane only)	37.7×10^{-3}	0.0	4.8	0.03

Part 3 Fuel combustion — liquid fuels and certain petroleum-based products for stationary energy purposes

Item	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
31	Petroleum based oils (other than petroleum based oil used as fuel)	38.8	27.9	0.0	0.0
32	Petroleum based greases	38.8	27.9	0.0	0.0
33	Crude oil including crude oil condensates	45.3 GJ/t	68.9	0.06	0.2
34	Other natural gas liquids	46.5 GJ/t	60.4	0.06	0.2
35	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.2	0.2
36	Gasoline for use as fuel in an aircraft	33.1	66.3	0.2	0.2
37	Kerosene (other than for use as fuel in an aircraft)	37.5	68.2	0.01	0.2
38	Kerosene for use as fuel in an aircraft	36.8	68.9	0.01	0.2
39	Heating oil	37.3	68.8	0.02	0.2
40	Diesel oil	38.6	69.2	0.1	0.2

Item	**Fuel combusted**	**Energy content factor** **(GJ/kL unless otherwise indicated)**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
41	Fuel oil	39.7	72.9	0.03	0.2
42	Liquefied aromatic hydrocarbons	34.4	69.0	0.02	0.2
43	Solvents if mineral turpentine or white spirits	34.4	69.0	0.02	0.2
44	Liquefied petroleum gas	25.7	59.6	0.1	0.2
45	Naphtha	31.4	69.0	0.00	0.02
46	Petroleum coke	34.2 GJ/t	90.8	0.06	0.2
47	Refinery gas and liquids	42.9 GJ/t	54.2	0.02	0.03
48	Refinery coke	34.2 GJ/t	90.8	0.06	0.2
49	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and (b) the petroleum based products mentioned in items 33 to 48.	34.4	69.0	0.02	0.2
50	Biodiesel	34.6	0.0	0.06	0.2
51	Ethanol for use as a fuel in an internal combustion engine	23.4	0.0	0.06	0.2
52	Biofuels other than those mentioned in items 50 and 51	23.4	0.0	0.06	0.2

Part 4 Fuel combustion — fuels for transport energy purposes

Division 4.1 Fuel combustion — fuels for transport energy purposes

Item	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
53	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.6	2.3
54	Diesel oil	38.6	69.2	0.2	0.5
55	Gasoline for use as fuel in an aircraft	33.1	66.3	0.04	0.7
56	Kerosene for use as fuel in an aircraft	36.8	68.9	0.01	0.7
57	Fuel oil	39.7	72.9	0.06	0.6
58	Liquefied petroleum gas	26.2	59.6	0.6	0.6
59	Biodiesel	34.6	0.0	1.2	2.2
60	Ethanol for use as fuel in an internal combustion engine	23.4	0.0	1.2	2.2
61	Biofuels other than those mentioned in items 59 and 60	23.4	0.0	1.2	2.2
62	Natural gas (light duty vehicles)	39.3 × 10-3 GJ/m3	51.2	5.5	0.3
63	Natural gas (heavy duty vehicles)	39.3 × 10-3 GJ/m3	51.2	2.1	0.3

Division 4.2 Fuel combustion — liquid fuels for transport energy purposes for post-2004 vehicles

Item	**Fuel combusted**	**Energy content factor GJ/kL**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
64	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.02	0.2
65	Diesel oil	38.6	69.2	0.01	0.6
66	Liquefied petroleum gas	26.2	59.6	0.3	0.3
67	Ethanol for use as fuel in an internal combustion engine	23.4	0.0	0.2	0.2

Division 4.3 Fuel combustion — liquid fuels for transport energy purposes for certain trucks

Item	**Fuel type**	**Heavy vehicles design standard**	**Energy content factor GJ/kL**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
				CO_2	**CH_4**	**N_2O**
68	Diesel oil	Euro iv	38.6	69.2	0.05	0.5
69	Diesel oil	Euro iii	38.6	69.2	0.1	0.5
70	Diesel oil	Euro i	38.6	69.2	0.2	0.5

Part 5 Consumption of fuels for non-energy product purposes

Item	Fuel consumed	Energy content factor (GJ/t unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
71	Solvents if mineral turpentine or white spirits	34.4 GJ/kL	Not applicable		
72	Bitumen	43.2	Not applicable		
73	Waxes	45.8	Not applicable		
74	Carbon black if used as a petrochemical feedstock	37.1	Not applicable		
75	Ethylene if used as a petrochemical feedstock	50.3	Not applicable		
76	Petrochemical feedstock other than those mentioned in items 74 and 75		Not applicable		

Part 6 Indirect (scope 2) emission factors from consumption of purchased electricity from grid

Item	State, Territory or grid description	Emission factor kg CO_2-e/kWh
77	New South Wales and Australian Capital Territory	0.89
78	Victoria	1.22
79	Queensland	0.91
80	South Australia	0.84
81	South West Interconnected System in Western Australia	0.87
82	Tasmania	0.12
83	Northern Territory	0.69

Schedule 2 Standards and frequency for analysing energy content factor etc for solid fuels

(subsections 2.5 (1), 2.6 (1) and 2.8 (1) and (2))

Item	Fuel combusted	Parameter	Standard	Frequency
1	Black coal (other than that used to produce coke)	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite
		Moisture	AS 1038.1—2001 AS 1038.3—2000	Each delivery
		Ash	AS 1038.3—2000	Each delivery
2	Brown coal	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 2434.6—2002	Monthly sample composite
		Moisture	AS 2434.1—1999	Each delivery
		Ash	AS 2434.8—2002	Each delivery
3	Coking coal	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite
		Moisture	AS 1038.1—2001 AS 1038.3—2000	Each delivery
		Ash	AS 1038.3—2000	Each delivery
4	Brown coal briquettes	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 2434.6—2002	Monthly sample composite
		Moisture	AS 2434.1—1999	Each delivery
		Ash	AS 2434.8—2002	Each delivery
5	Coke oven coke	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite

Item	Fuel combusted	Parameter	Standard	Frequency
		Moisture	AS 1038.2—2006	Each delivery
		Ash	AS 1038.3—2000	Each delivery
6	Coal tar	Energy content factor	N/A	Monthly sample composite
		Carbon	N/A	Monthly sample composite
		Moisture	N/A	Each delivery
		Ash	N/A	Each delivery
7	Solid fuels other than those mentioned in items 1 to 5	N/A	N/A	N/A
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
10	Dry wood	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery

Item	Fuel combusted	Parameter	Standard	Frequency
11	Green and air dried wood	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
			CEN/TS 14774-3:2004	
		Ash	CEN/TS 15403:2006	Each delivery
12	Sulphite lyes	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
			CEN/TS 14774-3:2004	
		Ash	CEN/TS 15403:2006	Each delivery
13	Bagasse	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
			CEN/TS 14774-3:2004	
		Ash	CEN/TS 15403:2006	Each delivery
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery

Item	Fuel combusted	Parameter	Standard	Frequency
15	Charcoal	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
16	Primary solid biomass fuels other than those items mentioned in items 10 to 15	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
			CEN/TS 14774-3:2004	
		Ash	CEN/TS 15403:2006	Each delivery

Schedule 3 Carbon content factors for fuels

(subsection 2.61 (1), sections 3.65, 4.66 and subsections 4.67 (2) and 4.68 (2))

Note 1 Under the 2006 IPCC Guidelines, the emission factor for CO_2 released from combustion of biogenic carbon fuels is zero.

Note 2 The carbon content factors in this Schedule do not include relevant oxidation factors.

Part 1 Solid fuels and certain coal-based products

Item	Fuel type	Carbon content factor tC/t fuel
Solid fossil fuels		
1	Black coal (other than that used to produce coke)	0.663
2	Brown coal	0.260
3	Coking coal	0.752
4	Brown coal briquettes	0.574
5	Coke oven coke	0.789
6	Coal tar	0.837
7	Solid fossil fuels other than those mentioned in items 1 to 5	0.574
Fuels derived from recycled materials		
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	0.585
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	0.250
Primary solid biomass fuels		
10	Dry wood	0
11	Green and air dried wood	0
12	Sulphite lyes	0
13	Bagasse	0
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	0
15	Charcoal	0
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	0

Part 2 Gaseous fuels

Item	**Fuel type**	**Carbon content factor (tC/m^3 of fuel unless otherwise specified)**
Gaseous fossil fuels		
17	Natural gas if distributed in a pipeline	5.52×10^{-4}
18	Coal seam methane that is captured for combustion	5.29×10^{-4}
19	Coal mine waste gas that is captured for combustion	5.34×10^{-4}
20	Compressed natural gas	5.52×10^{-4}
21	Unprocessed natural gas	5.52×10^{-4}
22	Ethane	8.87×10^{-4}
23	Coke oven gas	1.83×10^{-4}
24	Blast furnace gas	2.55×10^{-4}
25	Town gas	6.41×10^{-4}
26	Liquefied natural gas	0.355 tC/kL of fuel
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	5.52×10^{-4}
Biogas captured for combustion		
28	Landfill biogas (methane) that is captured for combustion	0
29	Sludge biogas (methane) that is captured for combustion	0
30	A biogas (methane) that is captured for combustion, other than those mentioned in items 28 and 29	0

Part 3 Liquid fuels and certain petroleum-based products

Item	**Fuel type**	**Carbon content factor (tC/kL of fuel unless otherwise specified)**
Petroleum based oils and petroleum based greases		
31	Petroleum based oils (other than petroleum based oils used as fuel)	0.737
32	Petroleum based greases	0.737
Petroleum based products other than petroleum based oils and petroleum based greases		
33	Crude oil including crude oil condensates	0.861 tC/t fuel
34	Other natural gas liquids	0.774 tC/t fuel

Item	Fuel type	Carbon content factor (tC/kL of fuel unless otherwise specified)
35	Gasoline (other than for use as fuel in an aircraft)	0.629
36	Gasoline for use as fuel in an aircraft	0.605
37	Kerosene (other than for use as fuel in an aircraft)	0.705
38	Kerosene for use as fuel in an aircraft	0.699
39	Heating oil	0.708
40	Diesel oil	0.736
41	Fuel oil	0.797
42	Liquefied aromatic hydrocarbons	0.654
43	Solvents if mineral turpentine or white spirits	0.654
44	Liquefied petroleum gas	0.422
45	Naphtha	0.597
46	Petroleum coke	0.856 tC/t fuel
47	Refinery gas and liquids	0.641 tC/t fuel
48	Refinery coke	0.856 tC/t fuel
49	Bitumen	0.951 tC/t fuel
50	Waxes	0.871 tC/t fuel
51	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and (b) the petroleum based products mentioned in items 33 to 50	0.654
Biofuels		
52	Biodiesel	0
53	Ethanol for use as a fuel in an internal combustion engine	0
54	Biofuels other than those mentioned in items 52 and 53	0

Part 4 Petrochemical feedstocks and products

Item	Fuel type	Carbon content factor (tC/t fuel unless otherwise specified)
Petrochemical feedstocks		
55	Carbon black if used as a petrochemical feedstock	1

Item	Fuel type	Carbon content factor (tC/t fuel unless otherwise specified)
56	Ethylene if used as a petrochemical feedstock	0.856
57	Petrochemical feedstock other than those mentioned in items 55 and 56	0.856
Petrochemical products		
58	Propylene	0.856
59	Polyethylene	0.856
60	Polypropylene	0.856
61	Butadiene	0.888
62	Stryrene	0.923

Note

1. All legislative instruments and compilations are registered on the Federal Register of Legislative Instruments kept under the *Legislative Instruments Act 2003*. See http://www.frli.gov.au.