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Department of Climate Change

NATIONAL GREENHOUSE AND ENERGY REPORTING SYSTEM MEASUREMENT

Technical Guidelines

for the estimation of greenhouse gas emissions by facilities in Australia

June 2009

thinkchange

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This document and supporting methodology workbooks are available on the Internet at the following address:
www.climatechange.gov.au/inventory

The Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories are at:
www.ipcc-nggip.iges.or.jp

Suggestions and comments would be appreciated. They should be addressed to the Manager, Australian National Greenhouse Gas Inventory, National Inventory Systems Team, Department of Climate Change, GPO Box 854, Canberra ACT 2601.

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Chapter 1 General

Part 1.1 Preliminary

Division 1.1.1 Overview

The *National Greenhouse and Energy Reporting Act 2007*, the *Regulations* under that Act and the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* establish the legislative framework for a national greenhouse and energy reporting system.

These Technical Guidelines embody the latest methods for estimating emissions and are based on the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* as amended ('the Determination') [1] by the *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1).* The Technical Guidelines provide additional guidance and commentary to assist Reporters in estimating greenhouse gas emissions for reporting under the NGER system and in general are applicable to the 2009-10 reporting year.

The objectives for the NGER system are set out in the *National Greenhouse and Energy Reporting Act 2007 (the Act)* and include:

- informing government policy formulation and the Australian public;
- meeting Australia's international reporting obligations;
- assisting Commonwealth, State and Territory government programs and activities;
- underpinning the introduction of an emissions trading scheme in the future; and
- avoiding duplication of similar reporting requirements in the States and Territories.

[1] The Determination was issued on the 27th June 2008. It is available at www.climatechange.gov.au/reporting/determination/index.html. In these Guidelines, indented text is based on the text of the Determination.

Thresholds for reporting

The Act makes reporting mandatory for corporations whose energy production, energy use, or greenhouse gas emissions meet certain specified thresholds. These thresholds are detailed in the *Regulations* and reproduced in the *National Greenhouse and Energy Reporting Guidelines*, prepared by the Department of Climate Change and available at www.climatechange.gov.au/reporting/guidelines/index.html.

The Determination was made under subsection 10 (3) of the Act and provides methods, and criteria for methods, for the estimation and measurement of the following items arising from the operation of facilities:

(a) greenhouse gas emissions;

(b) the production of energy; and

(c) the consumption of energy.

The structure of *the Determination* is designed to facilitate the integration of corporate and facility level data provided under the Act with international data standards on greenhouse emissions estimates. Descriptions of emissions sources are based on those provided in the *IPCC Guidelines for National Greenhouse Gas Inventories*, while estimation methods are based on those used by the Department of Climate Change in preparing the Government's annual submission to the UNFCCC in the *National Inventory Report*.

These Technical Guidelines do not provide guidance on issues concerning the definition of a facility or who should report the emissions from a particular facility. For guidance on these questions, consult the *National Greenhouse and Energy Reporting Guidelines*, prepared by the Department of Climate Change and available at www.climatechange.gov.au/reporting/guidelines/index.html.

Emissions

Emissions are defined in the *Regulations* as the release of greenhouse gas into the atmosphere. Scope 1 emissions are distinguished from scope 2 emissions. These Guidelines are largely concerned with scope 1 emissions. Scope 1 emissions concern emissions released from a facility as a direct result of the activities of the facility.

The greenhouse gases covered by these Guidelines are defined in the *Regulations* and include:

- carbon dioxide;
- methane;
- nitrous oxide;
- specified hydrofluorocarbons
- specified perfluorocarbons; and
- sulphur hexafluoride.

Scope 2 emissions are a form of indirect emission and occur principally at electricity generators as a result of electricity consumption at another facility. They are recorded principally as a measure of what might happen to national emissions as a result of the consumption of electricity from facilities. Scope 2 emissions are covered only in chapter 7.

Coverage of Scope 1 emission sources in the Determination is given by the following categories:

(a) fuel combustion, which deals with emissions released from fuel combustion (see Chapter 2); and
(b) fugitive emissions from fuels, which deals with emissions mainly released from the extraction, production, processing and distribution of fossil fuels (Chapter 3); and
(c) industrial processes emissions, which deals with emissions released from the consumption of carbonates and the use of fuels as feedstocks or as carbon reductants, and the emission of synthetic gases in particular cases (see Chapter 4); and
(d) waste emissions, which deals with emissions mainly released from the decomposition of organic material in landfill or wastewater handling facilities (see Chapter 5).

The most important source is emissions from fuel combustion, which accounts for over 60 per cent of the emissions reported in the national greenhouse gas inventory.

The scope of the *Determination* does not include land based emissions covered by the UNFCCC categories 'Agriculture' and 'Land Use, Land Use Change and Forestry'. However, emissions from fuel combustion or any other emission source

listed above and which occurs from a facility operating within a land-based industry are, nonetheless, covered by the *Determination*.

Updates of these Guidelines

It is recognised that these Technical Guidelines will need to be updated as new information on emissions estimation methods becomes available. This will need to be balanced against the need to maintain time-series consistency of the emissions data as far as possible. Reflecting the need for this balance, it is planned that these Guidelines will be updated each year only for updated Scope 2 emission factors (see Chapter 7), while other revisions will occur on a periodic basis. It is planned that the Technical Guidelines will be updated periodically to:

- provide Methods for emission sources where currently there are gaps or omissions in the Methods currently available;
- take account of new documentary standards applicable to the estimation of emissions under Methods 2, 3 and 4;
- take account of new information in relation to Method 1 emission factors; and
- take account of new information in relation to the Methods detailed in the *Determination*.

A full review of emission factors used for Method 1 will be undertaken within 5 years.

Specific review of topics for refinement and elaboration of the *Determination* will be continued during 2009, including the treatment of fugitive emissions from coal mining; the treatment of carbon capture and storage; certain elements in the solid waste disposal and wastewater sectors and other issues that may arise as a result of feedback received or from international developments.

1.4 Overview — methods for measurement

Emissions are rarely measured through direct observation and are most often estimated by reference to readily observable variables that are closely related to greenhouse gas emissions such as the quantity of fossil fuels consumed.

These Guidelines provide Methods that allow for both direct emissions monitoring and the estimation of emissions through the tracking of observable, closely-related variables. This framework reflects the approaches of the international guidelines governing the estimation of national greenhouse gas inventories and, similarly, national practice such as for the *EU Guidelines for the Monitoring and Reporting of*

Greenhouse Gas Emissions and as foreshadowed in the US EPA Proposed Mandatory Greenhouse Gas Reporting Rule.

At its simplest, emissions may be estimated by reference to reportable data such as fossil fuel consumption, evidenced by invoices, and the use of specified emission factors provided in these Guidelines. For emissions from fuel combustion, for example, data on consumption of a particular fuel would be multiplied by a specific emission factor for that fuel to generate an emissions estimate. A similar approach has been used for over a decade in the voluntary reporting program *Greenhouse Challenge Plus* and before that, *Greenhouse Challenge*.

Greater levels of complexity and measurement effort may in some circumstances produce better estimates of emissions at facility level. This may result from, for example, sampling and analysis of a fuel consumed for its carbon content and other qualities that will affect actual emissions generated by its combustion at a facility. In Australia, this kind of approach to emissions estimation is already widely used in the electricity industry - in part for commercial reasons and in part because of the reporting processes under the *Generator Efficiency Standards* program.

Direct monitoring of emissions is also potentially an important approach to emissions estimation. While not common, such direct monitoring already occurs in some form in some instances such as in the coal industry, where state legislation requires the monitoring of methane levels for health and safety reasons.

Each of these broad approaches has been incorporated into the Guidelines as Methods for the estimation of emissions.

In particular four Methods have been described which provide a framework for emissions estimation for a range of purposes.

By drawing on existing emission estimation practices where possible the Guidelines aim to minimise the reporting burden on corporations. As indicated above, there are many instances where higher order methods (2, 3 and 4 set out below) already reflect current commercial or regulatory practice.

The provision for Reporters to select Methods for the estimation of emissions also allows Reporters to make their own judgements to balance the costs of using the higher-order methods with the benefits of potentially improved emission estimates.

A Framework for Method selection

The four Methods can be broadly described by the following:

Method 1: the National Greenhouse Accounts default method

Method 1 provides a class of estimation procedures derived directly from the methodologies used by the Department of Climate Change for the preparation of the *National Greenhouse Accounts*. The use of methodologies from the *National Greenhouse Accounts* also anchors Method 1 within the international guidelines adopted by the UN Framework Convention on Climate Change for the estimation of greenhouse emissions.

Method 1 specifies the use of designated emission factors in the estimation of emissions. These emission factors are national average factors determined by the Department of Climate Change using the Australian Greenhouse Emissions Information System (AGEIS).

Although significantly updated, this Method is very similar in approach to that used by many corporations for over a decade to report emission estimates under the *Greenhouse Challenge Plus* program.

Method 1 is likely to be most useful for emission sources where the source is relatively homogenous, such as from the combustion of standard liquid fossil fuels, where the emissions resulting from combustion will be very similar across most facilities.

Estimates of emissions will be able to be calculated under Method 1 by Reporters using tools provided by the Department of Climate Change.

Method 2: a facility-specific method using industry sampling and Australian or international standards listed in the Determination or equivalent for analysis of fuels and raw materials to provide more accurate estimates of emissions at facility level.

Method 2 enables corporations to undertake additional measurements - for example, the qualities of fuels consumed at a particular facility - in order to gain more accurate estimates for emissions for that particular facility.

Method 2 draws on the large body of Australian and international documentary standards prepared by standards organisations to provide the benchmarks for procedures for the analysis of, typically, the critical chemical properties of the fuels being combusted.

Method 2 is likely to be most useful for fuels which exhibit some variability in key qualities, such as carbon content, from source to source. This is the case for coal in Australia.

Method 2 is based on existing technical guidelines used by reporters under the *Generator Efficiency Standards* program. The possibility to report using this, higher order, approach is extended by the *Determination* from the electricity industry to all major consumers of fossil fuels.

Method 3: a facility-specific method using Australian or international standards listed in the Determination or equivalent standards for both sampling and analysis of fuels and raw materials

Method 3 is very similar to Method 2, except that it requires, additionally, Reporters to comply with Australian or international documentary standards for sampling (of fuels or raw materials) or equivalent as well as documentary standards for the analysis of fuels.

Method 4: direct monitoring of emission systems, either on a continuous or periodic basis.

Method 4 provides for a different approach to the estimation of emissions. Rather than analysing the chemical properties of inputs (or in some case, products), Method 4 provides approaches to enable direct monitoring of greenhouse gas emissions arising from an activity. This can provide a higher level of accuracy in certain circumstances, depending on the type of emission process although it is more data intensive than other approaches. Such direct monitoring already occurs, for example, in underground coal mines reflecting the nature of the emission process and the importance of relatively accurate data to support health and safety objectives.

As for Methods 2 and 3, there is a substantial body of documented procedures on monitoring practices and state and territory government regulatory experience that provide the principal sources of guidance for the establishment of such systems.

It is intended that the Reporter may select different methods for each source. For example, the Reporter may select different methods for different fuels and different methods for individual gases, subject to certain restrictions. In part, these differences reflect Method availability. For example, for solid fuels, only Method 1 has been provided for methane and nitrous oxide, reflecting the minor nature of the emission sources, whereas four methods are available for carbon dioxide.

1.5 Overview — consumption and production of energy

Methods for the estimation of the energy content of fuels produced and fuels consumed is addressed in Chapter 6. Data collected for the estimation of emissions from fuel combustion as set out in Chapter 2 will serve a dual purpose as the data for the consumption of energy. Separate collections are required, however, for the quantities of production of energy which, in general, do not enter directly into emission estimations.

1.6 Overview — scope 2 emissions

These Guidelines principally deal with Scope 1 emissions. These are direct emissions that arise on-site from the activities of a corporation. There are a wide variety of emission sources that require a range of procedures to be described to cover the complexity of the emission pathways.

Scope 2 emissions arise principally at an electricity generator as a result of the purchase of electricity by a corporation. The method for the estimation of scope 2 emissions is given in chapter 7. These scope 2 factors will be updated annually to reflect the latest data on the mix of electricity generation sources, which is a major determinant of the factors.

1.7 Overview — assessment of uncertainty

Chapter 8 deals with the assessment of statistical uncertainty for scope 1 emissions estimates.

It is recognised that these calculations of uncertainty can be complex and relatively imprecise. A standardised approach to estimation of uncertainty of emissions estimates has been provided in Chapter 8.

Division 1.1.2 Definitions and Interpretations

Definitions of key terms used in these Guidelines are to be found at Appendix B. These definitions are drawn from both the *Regulations* and the *Determination*.

Many of the estimation methods reference documentary standards developed by, inter alia, standards organisations. Section 1.9 indicates that any standard, instrument or other writing must have been in force at 1 July 2009 to be applicable to an emissions estimation method. This means that any standard or similar instrument released after 1 July 2009 is not able to be referenced in a higher-order method. However, it is intended that the Determination will be reviewed at periodic intervals to consider recognition of such newly developed documentary standards.

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 2009.

1.10 Meaning of *source*

Sources of emissions are based on those provided in the *IPCC Guidelines for National Greenhouse Gas Inventories* and are defined in *the Determination*. The categories of source are listed in the table below and also correspond to a chapter heading in *the Determination* while the source of emissions in column 3 relate to the divisions within the chapters.

Item	Category of source	Source of emissions
1	Fuel combustion	
1A		Fuel combustion
2	Fugitive emissions	
2A		Underground mines
2B		Open cut mines
2C		Decommissioned underground mines
2D		Oil or gas exploration
2E		Crude oil production
2F		Crude oil transport
2G		Crude oil refining
2H		Natural gas production or processing (other than emissions that are vented or flared)
2I		Natural gas transmission
2J		Natural gas distribution
2K		Natural gas production or processing - flaring

Item	Category of source	Source of emissions
2L		Natural gas production or processing - venting
2M		Carbon capture and storage
3	Industrial processes	
3A		Cement clinker production
3B		Lime production
3C		Use of carbonates for the production of a product other than cement clinker, lime or soda ash
3D		Soda ash use
3E		Soda ash production
3F		Ammonia production
3G		Nitric acid production
3H		Adipic acid production
3I		Carbide production
3J		Chemical or mineral production, other than carbide production, using a carbon reductant
3K		Iron, steel or other metal production using an integrated metalworks
3L		Ferroalloys production
3M		Aluminium production
3N		Other metals production
3O		Emissions of hydrofluorocarbons and sulphur hexafluoride gases
4	Waste	
4A		Solid waste disposal on land
4B		Wastewater handling (industrial)
4C		Wastewater handling (domestic or commercial)
4D		Waste incineration

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.

Time series consistency is also an important principle for measuring emissions. Chapter 5 of Volume 1 of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories provides a detailed discussion of the issue. In short reporters should aim to estimate all emissions in a time series consistently, which means that as far as possible, the time series should be calculated using a consistent method and data sources over time. Restrictions on the method to be used for a source, provided in Division 1.2.2, and the criteria for measurement, provided in Part 1.3, and Divisions 2.2.5, 2.3.6, 2.4.6 and 4.2.5, have been put in place to promote time series consistency. These principles are derived from those that apply to the preparation of national inventories.

Note that there is a difference in meaning between the common usage of the word "confidence" and its statistical usage in relation to ‘95% confidence level’. For an explanation of ‘95% confidence level’ please refer to Chapter 8.

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.

Uncertainty may be estimated for the corporation’s emissions as a whole. This is a voluntary reporting category.

1.15 Units of measurement

Standard units of measurement are prescribed for the standard reportable items.

Emissions of each greenhouse gas should be estimated and reported in tonnes of CO_2-equivalent. Conversion factors from tonnes of emissions of each greenhouse gas to tonnes of emissions of carbon dioxide equivalent for that gas are called Global Warming Potentials and are listed in the Regulations and reproduced in Appendix C.

Emission estimation methods utilise standard units of measurement for solid, gaseous and liquid fuels, unless otherwise specified. For gaseous fuels, the standard unit of measurement is cubic metres, although allowance is made for measurement in gigajoules if data is available in those units.

The standard units for fuels should also be used for reporting. For example, solid fuels should be reported in tonnes.

(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

This Division sets out the rules for a Reporter to change the Method of emissions estimation chosen. It is intended to strike a balance between the important objectives of maintaining consistency for a facility's emission estimates over time and leaving open the opportunity for a Reporter to improve their emissions estimates by adopting a higher order Method at any time.

Consequently, for an emissions source, once a Method has been selected by a Reporter, this selection should be maintained throughout a minimum four year period unless a Method with a higher number is chosen. After four years, a Reporter may select a lower order method.

(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

Method 4 provides for direct measurement of emissions of greenhouse gases. Such measurement systems can be established, for example, in flues, stacks, pipes or ducts and may be applicable in a number of industries, although not all.

Method 4 establishes a framework for the design, installation, performance and maintenance of direct emissions measurement systems for stationary emission sources and a guide to measurement, recording, and standardized reporting for estimating greenhouse gas emissions.

Two systems for direct emissions monitoring are available including:

(a) Continuous emissions monitoring (***CEM***);

(b) Periodic emissions monitoring (***PEM***).

The use of Method 4 by corporations will likely depend on a number of factors including the type of emissions process, the structures of the facility and any current direct measurement systems that corporations may have in place for measuring pollutants for other purposes.

The general framework for Method 4 draws on the following publications:

- U.S. Environmental Protection Agency. 2003. Code of Federal Regulations: Standards of Performance for New Stationary Sources. Appendix A – *Test Methods*. 40 CFR 60 Appendix A. Washington, D.C. These methods can be obtained from: http://www.epa.gov/ttn/emc/promgate.html

- The Commission of the European Communities, Commission Decision establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council. Brussels, 2006. This document can be obtained from: http://ec.europa.eu/index_en.htm

- The Environmental Protection Agency, Load Calculation Protocol for use by holders of NSW environment protection licenses when calculating assessable pollutant loads. Department of Environment and Conservation (NSW), February 2005. This document can be obtained from: http://www.environment.nsw.gov.au/licensing/lblprotocol/

- Department of Environment and Heritage, National Pollutant Inventory – Emission Estimation Manual for Fossil Fuel Electric Power Generation, Version 2.4, March 2005. This document can be obtained from: http://www.npi.gov.au/

- West Australian Department of Environment and Conservation, Department of Environment and Conservation Continuous Emissions Monitoring System (CEMS) Code for Stationary Source Air Emissions, October 2006. This document can be obtained from http://www.dec.wa.gov.au/

Division 1.3.2 Operation of method 4 (Continuous Emissions Monitoring)

Continuous Emissions Monitoring (CEM) systems are designed to monitor real-time occurrence of emissions. The aim of the CEM method is to provide the framework for calculating emissions and also to provide standards for the location of sampling positions, measurement of flow rates and gas concentrations and the frequency of measurements.

Subdivision 1.3.2.1 Method 4 (CEM)

1.21 Method 4 (CEM) — estimation of emissions

CEM systems may record emissions automatically via a computer or it maybe necessary for emissions to be calculated manually. The equation in 1.21 (1) provides a method to be used to calculate emissions manually from direct emissions monitoring under CEM systems. The equation uses the data gathered from flow rate and gas analyser equipment to calculate mass emissions.

In order to convert volumetric flow rates to mass flow rates accurately, direct measurement also requires the estimation of temperature and pressure to reduce the amount of error that is associated with the variability of density factors used to convert from volume of a gas to the mass of a gas. The equation in 1.21 (1) is cited from the report:

- Mark, M., Worrall, R., Mallett, C., and Xue, S. (2001). Measuring and Reporting Greenhouse Gas Emissions. ACARP Project C8061. CSIRO Exploration and Mining Report 805C.

This report can be obtained from: http://www.acarp.com.au/reports.aspx.

(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:

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

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***) (released from the source) 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.

The following paragraphs (2) to (5) provide the means to convert the emission estimates calculated using the above equation into hourly emission estimates in CO_2-e tonnes.

(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.

Example: Continuous emissions monitoring of CH_4 from fugitive emissions associated with underground coal mining.

Step 1. Calculate the emission rate for each measurement period using the equation in section 1.21.

Measurement (time)	MM_{ct} (CO_2 tonnes per kilomole)	P_{ct} (kPa)	FR_{ct} (M^3/sec)	C_{jct} (v/v)	Gas constant	T_{ct} (degrees Kelvin)	Emission rate (CH_4 tonnes per sec)	Emission rate (CO_2-e tonnes per sec)
	a	b	c	d	e	f	g	H
1.00PM	0.01604	101.300	300	0.009	8.314	295.0	1.79E-03	3.76E-02
1.15PM	0.01604	101.320	310	0.012	8.314	295.5	2.46E-03	5.17E-02
1.30PM	0.01604	101.315	307	0.011	8.314	295.4	2.23E-03	4.69E-02
1.45PM	0.01604	101.315	305	0.010	8.314	295.1	2.02E-03	4.24E-02
2.00PM	0.01604	101.310	303	0.010	8.314	295.2	2.01E-03	4.21E-02
2.15PM	0.01604	101.315	304	0.011	8.314	295.3	2.21E-03	4.65E-02
2.30PM	0.01604	101.320	308	0.011	8.314	295.3	2.24E-03	4.71E-02
2.45PM	0.01604	101.320	311	0.012	8.314	295.4	2.47E-03	5.19E-02

Step 2. Calculate the average emissions rate for an hour by summing the emission estimates in column h of the table and divide by the number of sample periods for the hour:

Average emission rate for the first hour (1.00PM to 2.00PM)

= (3.76E-02+5.17E-02+4.69E-02+4.24E-02)/4

= 4.46E-02 CO_2-e tonnes per second

Average emission rate for the second hour (2.00PM to 3.00PM)

= (4.21E-02+4.65E-02+4.71E-02+5.19E-02)/4

= 4.69E-02 CO_2-e tonnes per second

Step 3. The mass emissions for the hour is then calculated by multiplying the average emission rate for the hour in step 1 by the number of seconds in an hour, which is 3600.

Therefore:

Emissions for the first hour = 4.46E-02 x 3600

160.7 tonnes CO_2-e for the hour

Emissions for the second hour = 4.69E-02 x 3600

168.8 tonnes CO_2-e for the hour

To aggregate emissions for a period, the hourly emissions estimates are summed together. For example, total emissions between 1.00 and 3.00pm in the above example is calculated by adding together 160.7 and 168.8 tonnes of CO_2-e which equals 329.5 tonnes of CO_2-e.

Subdivision 1.3.2.2 Method 4 (CEM) — use of equipment

1.22 Overview

CEM systems have a number of specific requirements, including the location of sampling positions, measuring flow rates and gas concentrations and the frequency of measurement. These specific components of CEM systems are founded on internationally recognised standards or methods. The organisations that have been cited include:

- Standards Australia (AS)
- International Organization for Standardization (ISO)
- United States Environmental Protection Agency (US EPA)

A detailed list of the standards cited and how to obtain them can be found in Appendix D.

The following requirements 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

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

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

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) Measurements by CEM must be taken frequently enough to produce data that is representative and unbiased.

(2) 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 (Periodic Emissions Monitoring)

Subdivision 1.3.3.1 Method 4 (PEM)

Whereas CEM systems are designed to measure real-time emissions estimates, Periodic Emissions Monitoring (PEM) systems are designed to measure emissions at periodic intervals (e.g. daily, weekly, monthly measurements) over a specified period. The equations for calculating emissions from flow rate and gas concentration data is closely related to that of the CEM approach, however the frequency of measurement and operational time of PEM is less than for CEM.

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.

Example: Periodic (e.g. monthly sampling regime) emissions monitoring of CH_4 from fugitive emissions associated with underground coal mining

Measurement (time)	MM_{ct} (CO_2 tonnes per kilomole)	P_{ct} (kPa)	FR_{ct} (M^3/sec)	C_{jct} (v/v)	Gas constant	T_{ct} (degrees Kelvin)	Emission estimate (CH_4 tonnes per sec)	Emission estimate (CO_2-e tonnes per sec)
	a	b	c	d	e	f	g	H
January	0.01604	101.320	270	0.009	8.314	296.0	1.60E-03	3.37E-02
February	0.01604	101.290	255	0.008	8.314	295.6	1.35E-03	2.83E-02
March	0.01604	101.280	260	0.009	8.314	295.4	1.55E-03	3.25E-02
April	0.01604	101.350	275	0.009	8.314	295.1	1.64E-03	3.44E-02
May	0.01604	101.400	280	0.010	8.314	295.5	1.85E-03	3.89E-02
June	0.01604	101.320	265	0.008	8.314	294.3	1.41E-03	2.96E-02
July	0.01604	101.260	260	0.008	8.314	294.0	1.38E-03	2.90E-02
August	0.01604	101.400	285	0.011	8.314	294.4	2.08E-03	4.37E-02
September	0.01604	101.500	295	0.012	8.314	295.5	2.35E-03	4.93E-02
October	0.01604	101.330	270	0.009	8.314	295.6	1.61E-03	3.37E-02
November	0.01604	101.450	290	0.013	8.314	296.2	2.49E-03	5.23E-02
December	0.01604	101.280	255	0.007	8.314	296.5	1.18E-03	2.47E-02

To obtain the annual emission estimate the following steps are then taken.

Step 1. Calculate the average emissions rate for the year by summing the monthly emission rate estimates in column h of table 1 and divide by the number of sample periods:

= (3.37E-02+2.83E-02+3.25E-02+3.44E-02+3.89E-02+2.96E-02+2.90E-02+4.37E-02+4.93E-02+3.37E-02+5.23E-02+2.47E-02)/12

= 3.59E-02 CO_2-e tonnes per second

Step 2. The emissions for the year is then calculated by multiplying the average emission rate for the year in step 1 by the number of seconds in a year, which is 31536000. Therefore:

Emissions for the year = 3.59E-02 x 31536000

= 1 130 729 tonnes CO_2-e

1.28 Calculation of emission factors

PEM data calculated in Method 4 can be used to calculate emission factors for use in Method 2 by dividing the emissions estimated from a PEM system by the amount of fuel combusted or raw material produced during the year.

(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) volumetric flow rates estimated in accordance with section 1.31; or
- (b) gas concentrations estimated in accordance with section 1.32; or
- (c) consumption of fuel or material input, estimated in accordance with Chapters 2 to 7; or
- (d) material produced, estimated in accordance with Chapters 2 to 7.

Example

If the annual methane emissions from an underground coal mine was 1130729 tonnes CO_2-e and 2500000 tonnes of Run-of-mine coal was extracted from the mine, the emission factor would be:

EF = 1 130 729 tonnes CO2-e / 2 500 000 tonnes ROM coal

EF = 0.45 tonnes CO_2-e / tonne ROM coal

The calculation of emission factors may apply to a number of industries including electricity generation and production of industrial products (e.g. nitric acid).

Subdivision 1.3.3.2 Method 4 (PEM) — use of equipment

1.29 Overview

PEM systems have a number of specific requirements, including the location of sampling positions, measuring flow rates and gas concentrations and the frequency of measurement. These specific components of PEM systems are founded on internationally recognised standards or methods. The organisations that have been cited include:

- Standards Australia (AS)
- International Organization for Standardization (ISO)
- United States Environmental Protection Agency (US EPA)

A detailed list of the standards cited and how to obtain them can be found in Appendix D.

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

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 mermanently-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

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

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) 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 minimum performance characteristics of CEM or PEM equipment must be measured in accordance with the requirements in 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

Part 2.1 Preliminary

2.1 Outline of Chapter

The principle greenhouse gas generated by the combustion of fossil fuels for energy is carbon dioxide. The quantity of gas produced depends on the carbon content of the fuel and the degree to which the fuel is fully combusted (i.e. the oxidation factor, which usually ranges between 98% and 99.5%). Small quantities of methane and nitrous oxide are also produced, depending on the actual combustion conditions. Methane may be generated when fuel is heated, but only partially burnt, and depends on combustion temperatures and the level of oxygen present. Nitrous oxide results from the reaction between nitrogen and oxygen in the combustion air.

The principle purpose of the combustion of fossil fuels in the Australian economy is for the consumption or use of energy. This chapter addresses the general case of the estimation of emissions from the combustion of fossil fuels for that purpose.

This Chapter provides for the following matters:

(a) emissions released from the following sources:
  (i) the combustion of solid fuels (see Part 2.2);
  (ii) the combustion of gaseous fuels (Part 2.3);
  (iii) the combustion of liquid fuels (Part 2.4);
  (iv) fuel use by certain industries (Part 2.5);
(b) the measurement of blended fuels (Part 2.6);
(c) the estimation of energy for certain purposes (Part 2.7).

Fuels used as carbon reductants—for example, as in the production of steel—or as certain feedstocks are addressed in Chapter 4.

Reporting context

Under subdivision 4.4.5 of the *Regulations,* Reporters should submit data for each individual fuel type on the quantity of fuel consumed for:

(a) electricity generation;

(b) transport (excluding international bunker fuels)

(c) carbon reductants or feedstocks;

(d) other stationary energy purposes; and

(e) fuels consumed without combustion.

For each fuel type the Reporter should also submit:

i) the amount of fuel consumed for each purpose (a) to (e);

ii) the emissions of each greenhouse gas for each purpose (a) to (d);

iii) the Method used to estimate the emissions (a) to (d); and

iv) the criterion used to estimate the amount of fuel consumed (a) to (e).

More detail on the reporting requirements are set out in Part 2.7A.

Part 2.2 Emissions released from the combustion of solid fuels

Division 2.2.1 Preliminary

2.2 Application

This Part applies to 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 emissions another method may be used that is consistent with the principles in section 1.13, *namely that the estimates are transparent, comparable, accurate and complete*. *Incidental source streams are defined in Appendix B*.

(3) If the principal activity of the facility is electricity generation (ANZSIC industry classification and code 2611), method 1 must not be used for estimating emissions of carbon dioxide for the main fuel combusted from the operation of the facility. *This limitation reflects current experience of generators that already estimate emissions with procedures from the Generator Efficiency Standards program on which Methods 2 and 3 are derived.*

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

Summary of available Methods, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 2.4	Section 2.4	Section 2.4
Method 2	Sections 2.5 and 2.6	NA	NA
Method 3	Section 2.12	NA	NA
Method 4	Part 1.3	NA	NA

NA is not available.

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

2.4 Method 1 — solid fuels

Method 1 is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. The approach is similar to that taken for the estimation of emissions from the Greenhouse Challenge Plus program. Estimates of emissions from the combustion of individual solid fuel types are made by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor for each relevant greenhouse gas (in this case, carbon dioxide, methane and nitrous oxide).

The list of solid fuels for which emissions must be calculated is given in Table 2.2.2 (taken from Schedule 1 of the *Regulations*).

Energy content and emission factors required for the estimation of emissions from the combustion of solid fuels using this approach are given below. These factors are intended to be default factors – to be used in the absence of better information about the qualities of the fuels combusted at a particular facility. (If better information on fuel qualities or emissions is available, the Reporter may utilise Method 2, 3 or 4).

Once selected the energy content factor (EC_i) for a particular fuel must be applied to all calculations of energy emissions from that fuel for a facility in the reporting year.

The emission factors for use in Method 1 have been estimated using the Australian Greenhouse Emissions Information System (AGEIS) operated by the Department of Climate Change. Consequently, they are determined simultaneously with the production of Australia's *National Greenhouse Accounts* ensuring that inventories of emissions at both facility and corporate levels are consistent with those of the national accounts.

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 fuel type *(i)* estimated under section 6.5.

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 each fuel as recorded in the table.

Table 2.2.2: Emission and energy content factors — 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 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 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 factors for coal products are measured on an as combusted 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. Notes on the sources of the factors listed above can be found at Appendix 2A.

Example

A facility consumes 20,000 tonnes of washed black coal for a purpose other than for the production of electricity or coke. The Reporter elects to use Method 1 *(Division 2.2.2)* for each of the three greenhouse emission gases (*j*) (carbon dioxide, methane and nitrous oxide), for the fuel type black coal. Emissions are estimated as follows:

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

where:

E_{ij} is the emissions of gas type (***j***) 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)* estimated under Division 2.2.5 measured in tonnes. **In this case it is 20,000 tonnes of black coal.**

EC_i is the energy content factor of fuel type ***(i)*** estimated under section 6.5. **In this case it is assumed to be 27 gigajoules per tonne for black coal.**

EF_{ijoxec} is the emission factor for each gas (which includes the effect of a default 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. **In this case, for carbon dioxide, it is 88.2 kg CO_2-e per gigajoule for black coal. For methane, the emission factor is 0.03 kilograms per gigajoule and for nitrous oxide, 0.2 kilograms per gigajoule.**

Emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) in tonnes of CO_2-e are estimated as follows:

Emissions of carbon dioxide from combustion of black coal:

= (20,000 x 27.0 x 88.2)/1,000

= 47,628 t CO_2-e

Emissions of methane from combustion of black coal:

= (20,000 x 27.0 x 0.03)/1,000

= 16 t CO_2-e

Emissions of nitrous oxide from combustion of black coal:

= (20,000 x 27.0 x 0.2)/1,000

= 108 t CO_2-e

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

Method 1 applies national emission factors to the estimation of emissions. This approach produces accurate estimates for each facility in the sense that they are expected to be neither over nor under-estimates, but the approach effectively averages out the variations in emission factors for the fuels that might be applicable for a particular facility. Better estimates of emissions at a particular facility may be obtained by sampling and analysing the fuels actually combusted at the facility for the intrinsic qualities of the fuels themselves that affect actual emission levels. These qualities include the carbon, ash and moisture content of a fuel and may vary reasonably significantly from source to source, particularly for coals.

Method 2 is derived from the methodologies published in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage and is designed to enable more accurate estimates of emissions to be made at a particular facility.

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis. Analysis of the fuels for carbon, energy, ash or moisture content must be done in accordance with listed Australian or international documentary standards or equivalent.

Division 2.2.3 also sets out a further choice for the estimation of emissions from solid fuel combustion, which is to estimate emissions with a) an assumed oxidation factor (sub-division 2.2.3.1) or b) to estimate the oxidation level by reference to additional information about the fuels combusted by the facility (Sub-division 2.2.3.2).

For sub-division 2.2.3.1, the oxidation factors adopted reflect current practice for the electricity generation industry in their estimation of emissions under the Generator Efficiency Standards program. The default oxidation factor listed by the Intergovernmental Panel in Climate Change is provided for other consumers of solid fuels.

Once the analysis of the fuel for carbon, ash and moisture has been completed, emissions may then be estimated in accordance with the equations specified in Section 2.5 (1) or 2.6 (1).

(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)*** estimated under section 6.5.

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 combusted 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 combusted 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.

Table 2.2.3 Analysis of solid fuels: standards and frequency of analysis for energy, carbon, moisture and ash

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

Item	Fuel combusted	Parameter	Standard	Frequency
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
		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
11	Green and air dried wood	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite

Item	Fuel combusted	Parameter	Standard	Frequency
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		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 CEN/TS 14774-3:2004	Each delivery
		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 CEN/TS 14774-3:2004	Each delivery
		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
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

Item	Fuel combusted	Parameter	Standard	Frequency
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery

Example

A facility consumes 100,000 tonnes of black coal with a carbon content of 75 per cent and an energy content of 28.5 gigajoules per tonne for purposes other than coke or electricity production. The Reporter elects to use Method 2 (*Division 2.2.3*) for the estimation of emissions of carbon dioxide and Method 1 (*Division 2.2.2*) for the estimation of emissions from methane and nitrous oxide.

Carbon dioxide emissions are estimated according to Method 2 as follows:

1. Estimate the carbon dioxide emission factor ($EF_{ico2ox,kg}$) for fuel type (*i*) as follows:

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

where:

$EF_{ico2ox,kg}$ the carbon dioxide emission factor for fuel type (*i*) in kilograms of CO_2-e per kilogram of fuel;

C_{ar} is the percentage of carbon in fuel type (***i***) as received for the facility. **In this case the percentage of carbon in black coal is estimated to be 75.**

$OF_{s,}$, 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.

= 75/100 x 0.98 x 3.664

= 2.69 kg of CO_2-e per kg of fuel

2. Estimate the carbon dioxide emission factor for fuel type (*i*) measured in kilograms of CO_2-e per gigajoule as follows:

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

where:

EF**$_{ico2ox,kg}$* is the carbon dioxide emission factor for fuel type (i***) measured in kilograms of CO_2-e per kilogram of fuel.

***EC**$_i$* is the energy content factor of fuel type (i) estimated under section 6.5. **In this case the energy content factor of black coal is estimated to be 28.5 GJ/t.**

= 2.69/28.5 x 1 000

= 94.4 kg of CO_2-e per gigajoule

3. Estimate emissions as follows:

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

where:

E**$_{ico2}$* means the emissions of carbon dioxide released from the combustion of a 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 estimated under Division 2.2.5.

***EC**$_i$* is the energy content factor of fuel type (i) estimated under section 6.5.

EF**$_{ico2oxec}$* is the carbon dioxide emission factor for fuel type (i***) measured in kilograms of CO_2-e per gigajoule.

= 100,000 x 28.5 x 94.4/1 000

= 269,040 tonnes of carbon dioxide emissions (CO_2-e).

Methane and nitrous oxide emissions are estimated according to Method 1 as follows:

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

where:

E**$_{ij}$* is the emissions of gas type (j***) 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)* estimated under Division 2.2.5 measured in tonnes.

EC_i is the energy content factor of fuel type (i) estimated under section 6.5.

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

Emissions of methane from combustion of black coal:

= (100,000 x 27.0 x 0.03)/1 000

= 81 t CO_2-e

Emissions of nitrous oxide from combustion of black coal:

= (100,000 x 27.0 x 0.2)/1 000

= 540 t CO_2-e

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

Sub-division 2.2.3.2 sets out the second option for the estimation of emissions from solid fuel combustion using an estimated oxidation level by reference to additional information about the fuels combusted by the facility. An alternative approach, using an assumed oxidation factor, is set out in sub-division 2.2.3.1.

(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)*** estimated under section 6.5.

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 combusted 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 combusted 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 combusted 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 combusted 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

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis.

As coal is a heterogeneous material, for the sample to be truly representative it must contain the correct proportions of each particle size present, as well as the correct proportions of particles of varying impurity content. Therefore, in the process of collecting a representative sample, each particle in the lot must have an equal probability of being sampled ('equal selection probability'); the representativeness of the sample being a function of the mass of the sample, or more correctly, the number of particles in the sample.

A mechanical sampling system, designed and operated in accordance with AS 4264 should be used to sample the coal or solid fuel. Ideally, this type of sampling system would be set up to obtain coal as it is either being loaded at the coal source or unloaded at the facility. One lot of coal will normally represent one day or one trainload of coal. If necessary, manual sampling of the coal may be used provided that the sampling equipment and procedure used is in accordance with AS 4264.

Sample preparation as required providing a laboratory sample for analysis is normally carried out in two steps:

Step 1: Initial crushing and subdivision of the samples as part of an operation that is integrated with the coal sampling;

Step 2: Final crushing and subdivision at the laboratory to provide the analysis sample.

Precision is defined as a measure of the extent to which the observations within a set agree with each other; usually expressed as twice the standard deviation (95% confidence level). Precision checks should be carried out on the sampling process to confirm that the sampling rate is acceptable. The procedure for determining the precision of coal sampling and sample preparation is prescribed in AS 4264.5. It is recommended that precision tests be undertaken on a yearly basis and whenever there is a change in the fuel source or a significant change in the quality characteristics of a particular fuel.

If several sources of fuels are being sampled through a given plant, sampling conditions and sample precision checks should be carried out on the source that exhibits the highest degree of heterogeneity.

Bias can be defined as the tendency to obtain a value that is either consistently higher or consistently lower than the reference value; in practice this is the difference between the reference value and the average result obtained from a large number of determinations. The recommended procedure for the estimation of bias in a coal sampling system is given in AS 4264.4. In the case of bias testing of mechanical samplers, the reference samples are usually stopped belt samples off a conveyor belt. For the purposes of verification of a coal sampling system, the coal samples taken for bias testing (pairs consisting of a reference sample and a sample taken by the coal sampler) should be analysed for total moisture and ash.

Bias testing should always be carried out on a new sampling system. For an existing system, the following verification procedure may be followed if there is some doubt about the conformance of the sampling system:

1. conduct a detailed technical audit of the sampling system;

2. correct any non-conformances that have been observed;

3. conduct a limited bias test on the system, usually with the coal that exhibits the widest stochastic variability in total moisture or ash, to provide a more quantitative verification that the sampling system is performing correctly.

Analysis of the fuels for carbon, energy, ash or moisture content must be done in accordance with listed Australian or international documentary standards or by an on-line analyser in accordance with section 2.8 (3). The listing of applicable standards for the analysis of solid fuels is given below. Equivalent standards to those listed may also be used. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2009. A NATA (National Association of Testing Authorities) accredited laboratory or similar laboratory complying with ISO 17025 should be used to conduct the analysis.

Minimum frequencies of analysis for solid fuels are also provided for in the table below. These frequencies correspond to those specified in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

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 (if any).

Note An appropriate standard for most solid mineral fuels 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 the table in section 2.5.

(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 the table in section 2.5.

(3) Analysis must be undertaken by an accredited laboratory that meets the requirements equivalent to those in AS ISO/IEC 17025:2005. However, analysis may be undertaken by an on-line analyser if:

(a) the analyser is calibrated in accordance with an appropriate standard; and

(b) analysis undertaken to meet the standard is done by a laboratory that meets the requirements equivalent to those in AS ISO/IEC 17025:2005.

Note An appropriate standard is AS 1038.24-1998, *Coal and Coke Analysis and Testing*, Part 24, Guide to the evaluation of measurements made by on-line coal analysers.

(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

Sampling of furnace and fly ash is needed if the method of sub-division 2.2.3.2 is adopted rather than the alternative method of sub-division 2.2.3.1.

It is recognised that the configuration of plant varies and measurement of carbon in ash should be based on representative operating conditions for the plant.

Furnace ash includes ash collected at the bottom of the furnace hopper of the coal unit and ash collected within the economiser hopper at the rear pass of the coal fired power plant. There is no standard procedure to collecting furnace ash or economiser hopper ash; however, in a wet extraction system, reasonable samples may be obtained by using sampling ladles to collect material from sluiceways. In a dry extraction system, good representative samples can be obtained directly from the conveyor. Particular care should be taken in attempting to obtain samples of furnace ash because of the inherent dangers associated with such operations.

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* or a standard that is equivalent to those standards.

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 or in a standard that is equivalent to one of those standards	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

Item	Procedure	Frequency
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

Method 3 is a variation on Method 2. Method 3 provides for the same requirements as Method 2 except that sampling of fuels should also be conducted in accordance with the Australian or international standards listed in section 2.12 or by an equivalent standard. Once sampling of the fuel has been conducted in accordance with the standard, the analysis of the fuel for carbon, ash and moisture should be conducted as for Method 2. Emissions may then be estimated in accordance with the equations set out in sections 2.5 (1) or 2.6 (1) in Method 2.

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:

Table 2.2.4: Sampling of solid fuels: standards

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
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

Item	Fuel	Standard
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 and Background

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.

Fuel types identified in the Determination are as specified in the Regulation, Schedule 1. The fuel types listed principally reflect the lists of fuels currently reported to the Australian Bureau of Agricultural and Resource Economics (ABARE), which ABARE uses to prepare reports, inter alia, on behalf of the Australian Government to the International Energy Agency.

The quantities of fuels consumed should exclude those quantities consumed for international transport purposes to reflect international reporting requirements for the national inventory. It is intended that this may be achieved by excluding international bunker fuels as defined in *National Greenhouse and Energy Reporting Regulations 2008*, Regulation 1.03, and that the point of differentiation between domestic and international consumption will be identical to that provided by the Customs Act 1901 which is used also for excise and GST purposes.

Division 2.2.5 specifies the criteria for the estimation of the amounts of each solid fuel type combusted from the operation of a facility during a year.

There are four criteria available for the estimation of quantities combusted reflecting differing levels of measurement effort and precision.

Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen by the Reporter to estimate combustion is required to be reported. Measuring equipment calibrated to a measurement requirement mentioned in Sections 2.16 and 2.17 refers to the standards required for measurement to support all commercial transactions covered by the National Measurement Act 1960 and associated instruments. These standards were also set out in the *Technical Guidelines for the Generator Efficiency Standards* program.

In Section 2.17 it is intended that measured data for fuels delivered (at the point of sale) would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the fuel consumed at the facility are less than 5% of fuel consumption for the facility during the year and that the stock changes by less than 1% during the year. It is intended that the analysis may be conducted by the supplier.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase their fuel and where the Reporter also does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out in section 1.13 of transparency, comparability, accuracy and completeness. Such data would be classified and reported as ‘BBB’ data.

The restriction on the choice of criteria at 2.14 (3) is designed to ensure time series consistency of the measurements.

2.14 Criteria for measurement — criterion A and restrictions on the use of all criteria

(1) For the purpose 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 in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the solid fuel involves a commercial transaction, the quantity of fuel combusted 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***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 2.16 (2) (a), is used to estimate the quantity of fuel combusted, then, in each year following that year, only criterion AA, or criterion AAA using paragraph 2.16 (2) (a), (respectively) is to be used.

Acquisition does not involve commercial transaction

(4) If the acquisition of the solid fuel does not involve a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
   (a) as provided in paragraph 2.16 (2) (a) (***criterion AAA***);
   (b) 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.

For AAA, calibration of the weighing system should be carried out as per the manufacturer's instructions and at least on an annual basis. Some types of weighing systems, such as belt weighers, will require more frequent calibration. Calibration masses should be traceable to the appropriate National Standard of measurement.

The maximum permissible errors for weighers set out in the *National Measurement Act 1960* and associated instruments are given in the table.

Maximum permissible errors for hopper weighers, belt weighers and automatic rail weighbridges for initial verification and when the equipment is in-service

Weigher	Accuracy Class	Maximum Permissible Error	
		I.V.	I.S.
Hopper weighers[1]	Class 0.2	±0.10%	±0.2%
	Class 0.5	±0.25%	±0.5%
	Class 1	±0.50%	±1.0%
	Class 2	±1.00%	±2.0%
Belt weighers (dynamic conditions)[2]	Class 0.5	±0.25%	±0.5%
	Class 1.0	±0.5%	±1.0%
	Class 2.0	±1.0%	±2.0%
Automatic Rail-weighbridges (% or weight of single wagon or total train, as appropriate)[2]	Class 0.2	±0.10%	±0.2%
	Class 0.5	±0.25%	±0.5%
	Class 1	±0.50%	±1.0%
	Class 2	±1.00%	±2.0%

I.V. = Initial verification
I.S. = In-service
Source: National Measurement Institute NMI R 107 Discontinuous Totalising Automatic Weighing Instruments (Totalising Hopper Weighers)[1]
National Measurement Regulations 1999[2]
Accuracy classes are defined in the *National Measurement Regulations 1999* and NMI R 107 document

Maximum permissible errors for weigh bridges (static conditions) for initial verification and when the equipment is in-service

Maximum permissible errors	for loads m expressed in verification scale intervals e			
initial verification	Class I	Class II	Class III	Class IIII
±0.5 e	0 ≤ m ≤ 50 000	0 ≤ m ≤ 5 000	0 ≤ m ≤ 500	0 ≤ m ≤ 50
±1 e	50 000 < m ≤ 200 000	5 000 < m ≤ 20 000	500 < m ≤ 2 000	50 < m ≤ 200
±1.5 e	200 000 < m	20 000 < m ≤ 100 000	2 000 < m ≤ 10 000	200 < m ≤ 1 000
In service	Class I	Class II	Class III	Class IIII
±1.0 e	0 ≤ m ≤ 50 000	0 ≤ m ≤ 5 000	0 ≤ m ≤ 500	0 ≤ m ≤ 50
±2.0 e	50 000 < m ≤ 200 000	5 000 < m ≤ 20 000	500 < m ≤ 2 000	50 < m ≤ 200
±3.0 e	200 000 < m	20 000 < m ≤ 100 000	2 000 < m ≤ 10 000	200 < m ≤ 1 000

Source: National Measurement Institute NMI R 76-1 Non-automatic Weighing Instruments. Part 1: Metrological and Technical Requirements — Tests

Accuracy classes for weigh bridges as defined in NMI R 76-1 document are:

Special accuracy – Class I
High accuracy – Class II
Medium accuracy – Class III
Ordinary accuracy – Class IIII

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 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 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 emissions another method may be used that is consistent with the principles in section 1.13, *namely that the estimates are transparent, comparable, accurate and complete*. *Incidental source streams are defined in Appendix B*.

(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 emissions of carbon dioxide for the main fuel combusted from the operation of the facility. *This limitation reflects current experience of generators that already estimate emissions with procedures from the Generator Efficiency Standards program on which Methods 2 and 3 are derived*.

Summary of available methods, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 2.20	Section 2.20	Section 2.20
Method 2	Sections 2.21	Section 2.27	NA
Method 3	Section 2.26	NA	NA
Method 4	Part 1.3	NA	NA

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

As for solid fuels, Method 1 for gaseous fuels is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. The approach is similar to that used for the Greenhouse Challenge Plus. Emissions for each gas type - carbon dioxide, methane or nitrous oxide - are estimated for individual fuel types by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor for each relevant greenhouse gas.

The list of gaseous fuels for which emissions must be calculated is given in Table 2.3.2. (taken from Schedule 1 of the *National Greenhouse and Energy Reporting Regulations 2008*).

Energy content and emission factors required for the estimation of emissions using this approach are given below. These factors are intended to be default factors – to be used in the absence of better information.

Once selected the energy content factor (EC_i) for a particular fuel must be applied to all calculations of energy emissions from that fuel for a facility in the reporting year.The emission factors listed have been estimated using the Australian Greenhouse Emissions Information System (AGEIS) operated by the Department of Climate Change. Consequently, they are determined simultaneously with the production of Australia's National Greenhouse Accounts ensuring that Reporter inventories are consistent with those national accounts.

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)*** estimated under section 6.5.

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 the table below.

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

Table 2.3.2 Emission and energy content factors — 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 that has reverted to standard conditions	39.3×10^{-3}	51.2	0.1	0.03
21	Unprocessed natural gas	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
22	Ethane	62.9×10^{-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
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

Notes on the sources of the factors listed above can be found at Appendix 2A.

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

As for solid fuels, Method 1 applies national average factors to the estimation of emissions. More accurate estimates of emissions at a facility level may be obtained by sampling and analysing fuels for qualities that affect emission levels when the fuel is combusted. These qualities include the composition of the constituent gases of the fuel combusted – for example, the share of methane in the combusted gas.

Method 2 is designed to enable more accurate estimates of emissions at a particular facility.

Method 2 is based on the methodologies published in the Technical Guidelines for the *Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

(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:

$\boldsymbol{E_{i,CO2}}$ 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.

$\boldsymbol{Q_i}$ 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.

$\boldsymbol{EC_i}$ is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

$\boldsymbol{EF_{iCO2ox,ec}}$ 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.

2.22 Calculation of emission factors from combustion of gaseous fuel

(1) For section 2.21, the emission factor $\boldsymbol{EF_{i,CO2,ox,ec}}$ 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 $\boldsymbol{EF_{i,CO2,,ox,kg}}$ 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:

$\boldsymbol{EF_{i,CO2,ox,kg}}$ 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.

$\boldsymbol{mol_y\%}$, 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.

$\boldsymbol{mw_y}$, 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 fuel type ***(i)*** obtained under section 2.21.

C_i is the density of fuel type (***i***) expressed in kilograms of fuel per cubic metre as obtained under subsection 2.24 (4). C_i is equivalent to $d_{y,\ total}/100$.

Subdivision 2.3.3.2 Sampling and analysis

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis. Analysis of the fuels for composition of constituent gases must be done in accordance with listed Australian or international standards. A listing of applicable standards is given in Section 2.23. Equivalent standards may also be selected. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2009.

A NATA (National Association of Testing Authorities) accredited laboratory or similar laboratory complying with ISO 17025 should be used to conduct the analysis.

Minimum frequencies of analysis of the gaseous fuels are also provided for in Section 2.25. These frequencies correspond to those specified in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage. With the results of the analysis, emissions may then be estimated in accordance the equations specified in Method 2.

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.

Table 2.3.3 Analysis of gaseous fuels: standards for analysis for energy and gas composition

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
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

Item	Fuel type	Energy content	Gas Composition
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 that has reverted to standard conditions	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
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)

Item	Fuel type	Energy content	Gas Composition
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)
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

Item	Fuel type	Energy content	Gas Composition
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.

Table: Frequency of analysis: gaseous fuels

Item	Fuel	Parameter	Frequency
1	Pipeline quality gases	Gas composition Energy content	Monthly 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

As for solid fuels, Method 3 is a variation on Method 2. Method 3 provides for the same requirements as Method 2 except that sampling of fuels should also be conducted in accordance with the Australian or international standards listed below or by an equivalent standard. Once sampling of the fuel has been conducted in accordance with the standard, the analysis of the fuel should be conducted as for Method 2. Emissions may then be estimated in accordance with the equations specified in Section 2.21 (1) in Method 2.

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.

Table 2.3.4 Sampling of gaseous fuels: standards

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 that has reverted to standard conditions	ASTM F 307–02 (2007)

Item	Gaseous fuel	Standard
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
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

Section 2.27 sets out a Method 2 for methane emissions from the combustion of gaseous fuels. The quantity of methane emissions from the combustion of fuels depends on the equipment used. In the case of gaseous fuels, small variations in

emissions are possible. Consequently, in this Method emissions may be estimated by substituting equipment-specific methane emission factors drawn from *2006 IPCC Guidelines for National Greenhouse Gas Inventories (Volume 2)* for the methane emission factors listed in the Table in Section 2.20.

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 $\boldsymbol{EF_{ijoxec}}$ 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.

The quantity of consumption of each of the fuel types specified in the Regulations, Schedule 1, are to be estimated according to one of the criterion set out below.

The fuel types listed principally reflect the lists of fuels currently reported to the Australian Bureau of Agricultural and Resource Economics (ABARE), which ABARE uses to prepare reports, inter alia, on behalf of the Australian Government to the International Energy Agency.

Separate estimates of the quantities of each fuel type consumed for the purpose of making electricity; for use as reductants or feedstocks; for use in transport (excluding international bunker fuels) and other stationary energy are required.

The quantities of fuels consumed for transport should exclude those quantities consumed for international transport purposes, if any, to reflect international reporting requirements for the national inventory. It is intended that this may be achieved by excluding international bunker fuels as defined in National Greenhouse and Energy Reporting Regulations 2008, Regulation 1.03, and that the point of differentiation between domestic and international consumption will be identical to that provided by the *Customs Act 1901* which is used also for excise and GST purposes.

As for solid fuels, there are four criteria available for the estimation of quantities combusted. Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen will need to be reported.

The criteria include:

(a) Criterion A - the amount of the fuel delivered for the facility during the year as evidenced by invoices or delivery records issued by the vendor of the fuel (2.29);

(b) Criterion AA - indirect measurement at the point of consumption - based on the amount of fuel delivered for the facility and adjusted for changes in stocks (2.30);

(c) Criterion AAA - direct measurement at the point of consumption - based on the amount of fuel combusted as estimated by measurement equipment that comply with specified standards (2.31 – 2.37);

(d) Criterion BBB - simplified measurement of consumption (2.38).

Measuring equipment requirements set out in Sections 2.31 to 2.37 are drawn from the requirements set out in the *Technical Guidelines for the Generator Efficiency Standards* program for gaseous fuels. These standards have been broadened to provide for a measurement threshold that is not technology-specific (2.35 (4)), reflecting comparable State-specific thresholds for small to medium-sized consumers.

In Sections 2.31 it is intended that measured data for fuels delivered would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the fuel consumed at the facility are less than 5% of fuel consumption for the facility during the year and that the stock changes by less than 1% during the year.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase fuel and where the Reporter also does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out 1.13 - of transparency, comparability, accuracy and completeness, and would be classified and reported as ‘BBB’ data.

For landfill gas, the BBB criterion includes provision for the estimation of gas quantities based on the practice available under the NSW GGAS scheme – see the

notice, *Determining the energy content of waste methane under the generation rules*, NSW IPART, 1 December 2006.

The restriction on the choice of criteria at 2.29 (3) is designed to ensure time series consistency of the measurements.

2.29 Criteria for measurement— criterion A and restrictions on the use of all criteria

(1) For the purposes of calculating the combustion of gaseous fuel from the operation of a facility for a year and, in particular, for $\boldsymbol{Q_i}$ in sections 2.20 and 2.21, the combustion must be estimated in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the gaseous fuel involves a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
   (a) the amount of the gaseous fuel, expressed in cubic metres or gigajoules, 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 2.30 (***criterion AA***);
   (c) as provided in section 2.31 (***criterion AAA***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 2.31 (3) (a), is used to estimate the quantity of fuel combusted, then, in each year following that year, only criterion AA, or criterion AAA using paragraph 2.31 (3) (a), (respectively) is to be used..

Acquisition does not involve commercial transaction

(4) If the acquisition of the gaseous fuel does not involve a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
   (a) as provided in section 2.31 (***criterion AAA***);
   (b) as provided in section 2.38 (***criterion BBB***).

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, as measured on a dry gas basis:

(a) air pressure of 101.325 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 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 liquid fuels.

2.39A Definitions for Part 2.4

In this Part:

petroleum based oils means petroleum based oils (other than petroleum based oil used as fuel).

Subdivision 2.4.1.1 Liquid fuels — other than petroleum based oils and greases

2.40 Available methods

(1) Subject to section 1.18, for estimating emissions released from the combustion of a liquid fuel, other than petroleum based oils and petroleum based greases used as lubricants, 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 emissions another method may be used that is consistent with the principles in section 1.13, *namely that the estimates are transparent, comparable, accurate and complete*. *Incidental source streams are defined in Appendix B*.

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.

Summary of available Methods by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 2.41	Section 2.41	Section 2.41
Method 2	Sections 2.42	Section 2.48	Section 2.48
Method 3	Section 2.47		
Method 4	Part 1.3		

Subdivision 2.4.1.2 Liquid fuels — petroleum based oils and greases

2.40A Available methods

(1) Subject to section 1.18, for estimating emissions of carbon dioxide released from the consumption, as lubricants, of petroleum based oils or petroleum based greases, consumed from the operation of a facility during a year, one of the following methods must be used:

(a) method 1 under section 2.48A;

(b) method 2 under section 2.48B;

(c) method 3 under section 2.48C.

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

Note The consumption of petroleum based oils and greases, as lubricants, releases emissions of carbon dioxide. Emissions of methane and nitrous oxide are not estimated directly for this fuel type.

Division 2.4.2 Method 1 — emissions of carbon dioxide, methane and nitrous oxide from liquid fuels other than petroleum based oils or greases

As for solid and gaseous fuels, Method 1 is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. The approach is similar to that taken for the estimation of emissions under the Greenhouse Challenge Plus program. Emissions are estimated for individual fuel types by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor for each relevant greenhouse gas (in this case, carbon dioxide, methane and nitrous oxide).

The list of liquid fuels for which emissions must be calculated is given in Appendix A (taken from Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008).

Energy content and emission factors required for the estimation of emissions using this approach are given below. These factors are intended to be default factors – to be used in the absence of better information.

Once selected the energy content factor (EC_i) for a particular fuel must be applied to all calculations of energy emissions from that fuel for a facility in the reporting year.

The emission factors listed have been estimated using the *Australian Greenhouse Emissions Information System (AGEIS)* operated by the Department of Climate Change. Consequently, they are determined simultaneously with the production of *Australia's National Greenhouse Accounts* ensuring that Reporter inventories are consistent with those *national accounts*.

Equipment specific factors for methane and nitrous oxide are provided for transport fleets. It is intended that the methane and nitrous oxide factors applicable to particular transport fleet should be utilised in the estimation of emissions for the fuel combusted for those fleets. No transport factors are provided for vehicles not registered for road use. Stationary energy factors for individual fuel types should be used in these cases.

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

(1) 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:

$\boldsymbol{E_{ij}}$ 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.

$\boldsymbol{Q_i}$ 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.

$\boldsymbol{EC_i}$ is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

$\boldsymbol{EF_{ijoxec}}$ 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***):

(a) for stationary energy purposes — see Table 2.42A; and

(b) for transport energy purposes — see Table 2.42B.

(2) In this section:

stationary energy purposes means purposes for which fuel is combusted that do not involve transport energy purposes.

transport energy purposes includes purposes for which fuel is combusted that consist of:

(a) transport by vehicles registered for road use; and

(b) rail, marine navigation and air transport.

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

Table 2.4.2A Emission and energy content factors — 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
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

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
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

Notes on the sources of the factors listed above can be found at Appendix 2A.

Table 2.4.2B Emissions and energy content factors — 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

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
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/m^3	51.2	5.5	0.3
63	Natural gas (heavy duty vehicles)	39.3 × 10-3 GJ/m^3	51.2	2.1	0.3

Notes on the sources of the factors listed above can be found at Appendix 2A.

Division 2.4.3 Method 2 — emissions of carbon dioxide from liquid fuels other than petroleum based oils or greases

As for solid and gaseous fuels, Method 1 applies national average factors to the estimation of emissions. More accurate estimates of emissions at a facility level may be obtained by sampling and analysing fuels for qualities that affect emission levels when the fuel is combusted. These qualities include the fuel's carbon content which may vary from fuel to fuel, albeit reasonably marginally for standard commercial fuels.

The list of liquid fuels for which emissions must be calculated is given in Table 2.4.3 (taken from Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008).

Method 2 is based on the methodologies published in the Technical Guidelines for the *Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

Subdivision 2.4.3.1 Method 2 — emissions of carbon dioxide from liquid fuels other than petroleum based oils or greases

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 factor of fuel type *(i)* estimated under section 6.5.

$EF_{iCO2ox,ec}$ 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 combusted, 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)* estimated under subsection 2.42 (1).

C_i is the density of the fuel expressed in kilograms of fuel per thousand litres as obtained using a Standard set out in section 2.45.

Subdivision 2.4.3.2 Sampling and analysis

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis. Analysis of the fuels for carbon, energy, ash or moisture content must be done in accordance with listed Australian or international standards. A listing of applicable standards is given in Section 2.45. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2009.

Unlike solid and gaseous fuels, standards for analysis have not been listed for a number of fuel types, reflecting the apparent absence of such standards particularly for volatile fuels. It is considered that for many liquid fuels that the use of Method 2 facility-specific emission factors would be likely to bring only marginal benefits in any case.

A NATA (National Association of Testing Authorities) accredited laboratory or similar laboratory complying with ISO 17025 should be used to conduct the analysis.

Minimum frequencies of analysis are also provided for in section 2.46. These frequencies correspond to those specified in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

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.

Table 2.4.3 Analysis of liquid fuels: standards for energy, carbon and density

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)
11	Fuel 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
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
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	Carbon	Quarterly or by delivery of

	fuel		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 from liquid fuels other than petroleum based oils or greases

As for solid and gaseous fuels, Method 3 is a variation on Method 2. Method 3 provides for the same requirements of Method 2 except that sampling of fuels should also be conducted in accordance with listed Australian or international standards in section 2.47 or by an equivalent standard. Once sampling of the fuel has been conducted in accordance with the standard, the analysis of the fuel for carbon and other factors should be conducted as for Method 2. Emissions may then be estimated in accordance with Method 2.

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.

Table 2.4.4 Sampling of liquid fuels: standards

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)

item	Liquid Fuel	Standard
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
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

item	Liquid Fuel	Standard
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 liquid fuels other than petroleum based oils or greases

Method 2 for the estimation of methane and nitrous oxide emissions from the combustion of liquid fuels is very similar to Method 1 - however the Reporter uses an equipment-specific emission factor set out in Schedule 1. This approach is only available for post-2004 vehicles and certain trucks with specified engine designs.

No sampling and analysis of fuels are required for this Method 2 for non-carbon dioxide emissions. This is because the emissions of methane and nitrous oxide depend, in general, on combustion conditions and the equipment used to combust the fuel. In contrast, the carbon dioxide emissions depend on the chemical qualities of the fuels themselves which can only be ascertained by analysis.

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 Table 2.4.5A; and

(b) for combustion of fuel by trucks that meet the design standards mentioned in column 2 of the table in Table 2.4.5B.

Table 2.4.5A 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

Notes on the sources of the factors listed above can be found at Appendix 2A.

Table 2.4.5B 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

Notes on the sources of the factors listed above can be found at Appendix 2A.

Example

A company consumes 35 000 kL (kilolitres) of diesel oil: 25 000 kL for transport purposes (with a post-2004 vehicle fleet) and 10 000 kL for stationary energy purposes. The Reporter elects to use Method 1 *(Division 2.4.2)* for each of the three greenhouse emission gases (*j*) (carbon dioxide, methane and nitrous oxide) for the diesel consumed for stationary energy purposes and Method 2 for the diesel consumed for transport by post 2004 vehicles. Emissions are estimated as follows:

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

where:

E_{ij} is emissions of gas type (***j***) 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 the fuel type (**i**) combusted from the operation of the facility during the year measured in tonnes and estimated under Division 2.4.6. **In this case 25 000 kL of diesel is used for transport purposes and 10 000kL of diesel is for stationary energy purposes**.

EC_i is the energy content factor of fuel type (i) estimated under section 6.5

(a) for stationary energy purposes — column 3 of the table 2.4.2A (Part 3 of Schedule 1 of the *Determination*). **In this case being 38.6 GJ/kL.**

(b) for post-2004 vehicles — column 3 of table 2.4.5A (Division 4.2 of Part 4 of Schedule 1 of the *Determination*). **In this case being 38.6 GJ/kL.**

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

(a) for stationary energy purposes — column 3 of the table 2.4.2A (Part 3 of Schedule 1 of the *Determination*); and

(b) for post-2004 vehicles — column 3 of table 2.4.5A (Division 4.2 of Part 4 of Schedule 1 of the *Determination*).

Therefore, emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) in tonnes of CO_2-e are estimated as follows:

Combustion of diesel oil for stationary energy purposes (Method 1):

Emissions of carbon dioxide

= (10 000 x 38.6 x 69.2)/1 000

= 26 711 t CO_2-e

Emissions of methane

= (10 000 x 38.6 x 0.1)/1 000

= 39 t CO_2-e

Emissions of nitrous oxide

= (10 000 x 38.6 x 0.2)/1 000

= 77 t CO_2-e

Combustion of diesel oil for transport purposes for post-2004 vehicles (Method 2):

Emissions of carbon dioxide

= (25 000 x 38.6 x 69.2)/1 000

= 66 778 t CO_2-e

Emissions of methane

= (25 000 x 38.6 x 0.01)/1 000

= 10 t CO_2-e

Emissions of nitrous oxide

= (25 000 x 38.6 x 0.6)/1 000

= 579 t CO_2-e

Division 2.4.5A Methods for estimating emissions of carbon dioxide from petroleum based oils or greases

This method applies to the consumption of petroleum based oils or greases as lubricants.

2.48A Method 1 — estimating emissions of carbon dioxide using an estimated oxidation factor

(1) For paragraph 2.40A (1) (a), method 1 for estimating emissions of carbon dioxide from the consumption of petroleum based oils or petroleum based greases using an estimated oxidation factor is:

$$E_{pogco2} = Q_{pog} \times EC_{pogco2} \times \frac{EF_{pogco2oxec}}{1\ 000}$$

where

E_{pogco2} is the emissions of carbon dioxide released from the consumption of petroleum based oils or petroleum based greases from the operation of the facility during the year measured in CO_2-e tonnes.

Q_{pog} is the quantity of petroleum based oils or petroleum based greases consumed from the operation of the facility for stationary energy purposes.

EC_{pogco2} is the energy content factor of petroleum based oils or petroleum based greases measured in gigajoules per kilolitre as mentioned in Part 3 of Schedule 1.

$EF_{pogco2oxec}$ has the meaning given in subsection (2).

(2) ***$EF_{pogco2oxec}$*** is:

(a) the emission factor for carbon dioxide 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 the petroleum based oils or petroleum based greases as mentioned in Part 3 of Schedule 1; or

(b) to be estimated as follows:

$$EF_{pogco2oxec} = OF_{pog} \times EF_{pogco2ec}$$

where:

OF_{pog} is the estimated oxidation factor for petroleum based oils or petroleum based greases.

$EF_{pogco2ec}$ is 69.9.

(3) For ***OF_{pog}*** in paragraph (2) (b), estimate as follows:

$$OF_{pog} = \frac{\left(C_{pog} - \text{Waste Oil}_{pog}\right)}{C_{pog}}$$

where:

C_{pog} is the consumption of petroleum based oils or petroleum based greases estimated in accordance with Division 2.4.6.

Waste Oil_{pog} is the quantity of waste oils, derived from petroleum based oils or petroleum based greases, transferred outside the facility, and estimated in accordance with Division 2.4.6.

2.48B Method 2 — estimating emissions of carbon dioxide using an estimated oxidation factor

For paragraph 2.40A (1) (b), method 2 is the same as method 1 but the emission factor ***$EF_{pogco2ec}$*** must be determined in accordance with Division 2.4.3.

2.48C Method 3 — estimating emissions of carbon dioxide using an estimated oxidation factor

For paragraph 2.40A (1) (c), method 3 is the same as method 1 but the emission factor $EF_{pogco2ec}$ must be determined in accordance with Division 2.4.4.

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.

The quantity of consumption of each of the fuel types specified in the Regulations, Schedule 1, are to be estimated according to one of the criterion set out below.

The fuel types listed principally reflect the lists of fuels currently reported to the Australian Bureau of Agricultural and Resource Economics (ABARE), which ABARE uses to prepare reports, inter alia, on behalf of the Australian Government to the International Energy Agency.

Separate estimates of the quantities of each fuel type consumed for the purpose of making electricity; for use as reductants or feedstocks; for use in transport (excluding international bunker fuels) and other stationary energy are required.

The quantities of fuels consumed for transport should exclude those quantities consumed for international transport purposes, if any, to reflect international reporting requirements for the national inventory. It is intended that this may be achieved by excluding international bunker fuels as defined in National Greenhouse and Energy Reporting Regulations 2008, Regulation 1.03, and that the point of differentiation between domestic and international consumption will be identical to that provided by the *Customs Act 1901* which is used also for excise and GST purposes.

Biogenic carbon fuels attract a zero carbon dioxide emission factor to ensure that the reporting system aligns with the reporting requirements of the IPCC reporting guidelines for national inventories and the practice, for example, of the EU for its Emissions Trading System. Non-carbon dioxide emissions from the combustion of biogenic fuels must be reported, however.

Division 2.4.6 specifies the criteria for the estimation of the amounts of liquid fuels combusted from the operation of a facility during a year. There are four criteria

available for the estimation of quantities combusted. Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen will need to be reported.

The criteria include:

(a) Criterion A - the amount of the fuel delivered for the facility during the year as evidenced by invoices or delivery records issued by the vendor of the fuel (2.50);

(b) Criterion AA - indirect measurement at the point of consumption - based on the amount of fuel delivered for the facility and adjusted for changes in stocks (2.51);

(c) Criterion AAA - direct measurement at the point of consumption - based on the amount of fuel combusted as estimated by measurement equipment that comply with specified standards (2.52);

(d) Criterion BBB - simplified measurement of consumption (2.53).

Measuring equipment calibrated to a measurement requirement in Section 2.52 refers to the standards required for measurement to support excise taxation arrangements.

In Section 2.52 it is intended that measured data for fuels delivered would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the fuel consumed at the facility are less than 5% of fuel consumption for the facility during the year and that the stock changes by less than 1% during the year.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase fuel and where the Reporter does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out 1.13 of transparency, comparability, accuracy and completeness. These data would be classified and reported as BBB criterion data.

The restriction on the choice of criteria at 2.50 (3) is designed to ensure time series consistency of the measurements.

2.50 Criteria for measurement— criterion A and restrictions on the use of all criteria

(1) For the purpose of calculating the combustion of a liquid fuel from the operation of a facility for a year and, in particular, for Q_i in sections 2.41 and 2.42 the combustion must be estimated in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the liquid fuel involves a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
(a) the amount of the liquid 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 2.51 (***criterion AA***);
(c) as provided in section 2.52 (***criterion AAA***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 2.52 (2) (a), is used to estimate the quantity of fuel combusted then, in each year following that year, only criterion AA, or criterion AAA using paragraph 2.52 (2) (a), (respectively) may be used.

Acquisition does not involve commercial transaction

(4) If the acquisition of the liquid fuel does not involve a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
(a) as provided in paragraph 2.52 (2) (a) (***criterion AAA***);(b) 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 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 emissions from petroleum refining, solid fuel transformation (coke ovens) and petrochemical production.

Division 2.5.1 Energy — petroleum refining

2.55 Application

This Division applies to 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 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 4.4.

(2) These emissions are taken to be emissions from fuel combustion.

Division 2.5.3 Energy — petrochemical production

2.59 Application

This Division applies to Source 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 emissions another method may be used that is consistent with the principles in section 1.13, *namely that the estimates are transparent, comparable, accurate and complete*. *Incidental source streams are defined in Appendix B*.

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 6866-08.

(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: D 6866-08 or a standard that is equivalent to that standard.

These standards include the following approaches to quantification:

Manual sorting (CEN/TS 15440:2006)

The manual sorting technique involves a sample of the solid blended fuel being sorted by hand into sub-fractions of biomass and non-biomass matter.

This procedure however is limited to fuels with a minimum particle size greater than 1 cm and only applies to blends of solid fuels.

Selective dissolution (CEN/TS 15440:2006)

The selective dissolution method for the determination of the biomass content involves the treatment of a sample of blended solid fuel with concentrated sulphuric acid topped with hydrogen peroxide. The biomass in the solid recovered fuel will selectively dissolve and the non-biomass will remain in the residue.

This technique is not applicable to the following blended fuels:

- charcoal, peat and solid fossil fuels like hard coal, coke, brown coal and lignite and to mixtures of these and solid recovered fuels;
- solid recovered fuels that contain more than 10 % of natural and/or synthetic rubber residues;
- solid recovered fuels that contain a combination of more than 5 % by weight of:
    - nylon, polyurethane or other polymers containing molecular amino groups;
    - biodegradable plastics of fossil origin;
- solid recovered fuels that contain a combination of more than 5 % by weight of:
    - wool or viscose;
    - non-biodegradable plastics of biogenic origin;
    - oil or fat present as a constituent of biomass.

Radiocarbon Analysis

The ASTM D 6866-08 standard also provides for a radiocarbon analysis method. The standard describes techniques for determining the biogenic content of solid, liquid and gaseous samples using radiocarbon analysis. The basic premise is that Carbon-14 (^{14}C), a radioactive isotope of carbon, has a half life of 5,730 years once it is no longer part of a living organism. This means that no ^{14}C will remain in fossil fuels because it has completely decayed, whereas in recent biomass, such as wood, a portion of ^{14}C still remains.

In effect, it is argued that biogenic matter contains a well characterized amount of carbon-14 that is easily distinguished from other materials such as fossil fuels that do

not contain any carbon-14. Since the amount of carbon-14 in biomass is well known, a percentage of biogenic carbon can be calculated easily from the overall carbon atoms in the sample.

This technique may be applied to any type of blended fuel including gaseous, liquid and solid fuels. The technique may be used to analyse the fuels directly or can be used to analyse the combustion gases once the fuel has being burned. The latter technique may be useful where direct emissions monitoring systems are already in place to measure CO_2 emissions and where sampling fuels can be difficult.

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.

Examples of non-energy use of fuels

- When used directly in a non-fuel manner – for example, fuels used directly as a solvent or a flocculent;
- When used as an ingredient in the manufacture of short-life products such as paints, cleaning agents and explosives manufactured for sale;
- When packaged for non-internal combustion engine use (restricted to containers less than 20 litres and kerosene, mineral turpentine, white spirit, liquid aromatic hydrocarbons and other petroleum products as defined in 10.28 of the schedule to the Excise Tariff Act);
- When blended with other products and then packaged for non-internal combustion engine use.

Note the point of consumption for bitumen used in asphalt is at the point of blending (combining the bitumen with other inputs to produce asphalt). Also note the end-use of purchased explosives are not reportable. However, where fuel is used to prepare explosives for use inside the operation of the facility (on site), the fuels used must be reported as fuel combusted.

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

Cogeneration processes are situations where two products – electricity and another product – are produced from the consumption of a single quantity of fuel.

This section specifies that for the purpose of complying with the *National Greenhouse and Energy Reporting Regulations 2008*, subregulation 4.23 (3), the quantity of fuel consumed and allocated to the production of electricity should be estimated using the efficiency method as described in the Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0 (the cogeneration guide) issued by World Resource Institute and World Business Council for Sustainable Development unless the heat is to be used for producing mechanical work when the work potential method described in the cogeneration guide may be used.

The efficiency method is the preferred method of the World Resource Institute and World Business Council for Sustainable Development. Limiting the approaches that can be used provides for more consistent interpretation of reported data and establishes well-understood boundaries for all data reported.

(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

Apportionment of fuels consumed between various purposes is considered to be less critical than the overall estimate of fuel consumed for a facility. Consequently, allocations of fuels consumed between purposes may be determined by facility records based on facility measurement techniques.

For the purpose of determining fuels consumed in transport, road transport means fuel consumed by a vehicle registered for road use.

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.

Part 2.7A Reporting

The *National Greenhouse and Energy Reporting Regulations 2008*, Division 4.4 specifies information relating to greenhouse gas emissions, energy production and energy consumption that must be included in a registered corporation's report for a reporting year if the corporation's group meets a threshold in subsection 13 (1) of the Act for that year.

The corporation's report must include information for the facility in relation to the amount of the consumption of each fuel type by purpose during the reporting year.

The categories of fuel consumption include:

(i) fuel combusted for producing electricity;

(ii) fuel consumed for producing a chemical product or metal product;

(iii) fuel combusted for transport, other than transport that involves the consumption of international bunker fuel;

(iv) fuel combusted for another purpose; and

(v) fuel consumed by a means other than combustion.

The criterion used to estimate the amount of fuel should also be reported.

Where electricity generation is the primary activity of the facility, all fuel may be allocated to fuel combusted for producing electricity. Where the primary activity is not electricity generation, and the allocation of fuels between purposes may be determined from facility records, the Reporter should allocate fuels between purposes according to this information. Where there are two purposes for the use of the fuels, and where the primary activity of the facility is not electricity generation, Reporters should consult the additional guidance provided in Section 2.70 to determine the amount of fuels consumed to be reported under this category, if any.

Where fuel is consumed primarily as a feedstock or carbon reductant in the production of a chemical or metal product, Reporters should consult the additional guidance provided in Chapter 4 – Industrial processes – and in section 2.69 to determine the amount of fuels consumed to be reported under this category, if any. This category should only include the amounts of fuels consumed in the industrial processes described in Chapter 4.

Where fuel is combusted for energy for transport, Reporters should consult the additional guidance provided in section 2.71. Amounts consumed from international bunker fuels should not be included.

Fuel combusted for another purpose includes all other fuel combusted for stationary energy purposes.

Where fuel is consumed by a means other than combustion, Reporters should consult additional guidance provided in section 2.68 to determine the amount of fuels consumed to be reported under this category, if any.

This data serves the purpose of Chapter 6 – reporting energy consumption – and the reporting of greenhouse emissions from fuel consumption.

The corporation's report must also include the amount of each greenhouse gas that is emitted during the reporting year from each fuel consumption source.

If methods 2, 3 or 4 are used the corporation's report must also include the following for the facility:

(a) the facility specific emission factor that the corporation used to estimate greenhouse gas emissions from consumption of that energy during the year;

(b) the energy content factor that the corporation used to measure the amount of that energy consumed in the facility during the year.

For the reporting of all other scope 1 emission sources, Reporters should refer to chapters 3, 4 and 5.

A list of fuels and other energy commodities is provided on the following page. Note the item numbers in the list correspond to the item numbers in Schedule 1 of the *Determination*.

Table 2.7A.1 Fuels and other energy commodities

Item	Fuels and other energy commodities
1	Black coal (other than that used to produce coke)
2	Brown coal
3	Coking coal
4	Brown coal briquettes
5	Coke oven coke
6	Coal tar
7	Solid fossil fuels other than those mentioned in items 1 to 5
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity
10	Dry wood
11	Green and air dried wood
12	Sulphite lyes
13	Bagasse
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity
15	Charcoal
16	Primary solid biomass fuels other than those mentioned in items 10 to 15
17	Natural gas distributed in a pipeline
18	Coal seam methane that is captured for combustion
19	Coal mine waste gas that is captured for combustion
20	Compressed natural gas that has reverted to standard conditions
21	Unprocessed natural gas
22	Ethane
23	Coke oven gas
24	Blast furnace gas
25	Town gas
26	Liquefied natural gas
27	Gaseous fossil fuels other than those mentioned in items 17 to 26
28	Landfill biogas that is captured for combustion (methane only)
29	Sludge biogas that is captured for combustion (methane only)
30	A biogas that is captured for combustion, other than items 28 and 29 (methane only)

Note: Item numbers are those in Schedule 1 of the *Determination*.

Item	Fuels and other energy commodities
31	Petroleum based oils (other than petroleum based oil used as fuel)
32	Petroleum based greases
33	Crude oil including crude oil condensates
34	Other natural gas liquids
35	Gasoline (other than for use as fuel in an aircraft)
36	Gasoline for use as fuel in an aircraft
37	Kerosene (other than for use as fuel in an aircraft)
38	Kerosene for use as fuel in an aircraft
39	Heating oil
40	Diesel oil
41	Fuel oil
42	Liquefied aromatic hydrocarbons
43	Solvents if mineral turpentine or white spirits
44	Liquefied petroleum gas
45	Naphtha
46	Petroleum coke
47	Refinery gas and liquids
48	Refinery coke
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.
50	Biodiesel
51	Ethanol for use as a fuel in an internal combustion engine
52	Biofuels other than those mentioned in items 50 and 51
72	Bitumen
73	Waxes
74	Carbon black if used as a petrochemical feedstock
75	Ethylene if used as a petrochemical feedstock
76	Petrochemical feedstock other than items 74 and 75
84	Uranium (U_3O_8)
85	Sulphur
86	Hydrogen

Appendix 2A Notes on Energy and Emission Factors

The following notes apply to energy content and emission factors in the following tables:

- Table 2.2.2
- Table 2.3.2
- Table 2.4.2A
- Table 2.4.2B
- Table 2.4.5A
- Table 2.4.5B

1. Energy value: Source – ABARE[1] (washed steaming). CO_2 emission factor: Source - National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

2. Energy value: Source - AGEIS database, Department of Climate Change (based on facility reports). CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports). Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

3. Energy value: Source – ABARE[1] (washed coking). CO_2 emission factor: Source - National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

4. Energy value: Source – ABARE[1]. CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports). Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

5. Energy value: Source – ABARE[1]. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

6. Energy value: Source – ABARE[1]. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (coal tar). Oxidation factor 0.99. Non-CO2 factors: Source: AGEIS database, Department of Climate Change.

7. See (4)

8. Energy value: Source – GHD Review of Sectoral Models, Internal report to the AGO, 2006. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

9. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.98. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

10. Energy value: Source: ABARE[1] (dry wood). Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

11. Energy value: Source: $ABARE_1$ (green wood). Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

12. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

13. Energy value: Source: $ABARE_1$. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

14. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

15. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

16. See (14)

17. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

18. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

19. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

20. See (17)

21. See (17)

22. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.995. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

23. Energy value: Source: $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change . Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

24. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.90. Oxidation factor 0.995. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.90.

25. Energy value: Source – $ABARE_2$ (synthetic natural gas). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.995. Non-CO_2 factors: Source: AGEIS database.

26. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

27. See (17)

28. Energy value: Source – $ABARE_1$. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

29. Energy value: Source – $ABARE_1$. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

30. See (28)

31. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (lubricants and greases). Oxidation factor 0.4. Non-CO_2 factors: nil.

32. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (lubricants and greases). Oxidation factor 0.4. Non-CO_2 factors: nil.

33. Energy value: Source – $ABARE_2$ (weighted average). CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: IPCC 2006 (Energy Industries). Derived using conversion factor of 0.95.

34. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: IPCC 2006 (Energy Industries). Derived using conversion factor of 0.95.

35. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

36. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

37. Energy value: Source – $ABARE_2$ (power kerosene). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

38. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

39. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

40. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

41. Energy value: Source – $ABARE_2$ (low sulfur). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

42. Energy value: Source – $ABARE_2$. Given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (assumed same as solvents). Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

43. Energy value: Source – $ABARE_2$. CO_2 emission factor: National Inventory Report 2006, Department of Climate Change . Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

44. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

45. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

46. Energy value: Source – IPCC 2006. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.98. Non-CO_2 factors: IPCC 2006, Manufacturing category. Derived using conversion factor 0.95.

47. Energy value: Source – $ABARE_1$ (refinery fuel). CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

48. See (46)

49. Energy value: Source – $ABARE_2$. Based on IPCC 2006, given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (set same as solvents). Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

50. Energy value: Source – Derived from US Department of Energy. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

51. Energy value: Source – $ABARE_2$. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

52. See (51).

53. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

54. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

55. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

56. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

57. Energy value: Source – $ABARE_2$ (low sulfur). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

58. Energy value: Source – Derived from $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

59. Energy value: Source – Derived from US Department of Energy, 2006. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

60. Energy value: Source – $ABARE_2$. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

61. See (60)

62. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: AGEIS database, Department of Climate Change.

63. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: AGEIS database, Department of Climate Change.

64. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

65. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

66. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

67. Energy value: Source – $ABARE_2$. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

68. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

69. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

70. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

Chapter 3 Fugitive emissions from fuels

Part 3.1 Preliminary

3.1 Outline of Chapter

This Chapter provides for fugitive emissions from fuels from the following sources:

(a) coal mining (see Part 3.2);

(b) oil and natural-gas (see Part 3.3).

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

Part 3.2 Coal mining

3.2.1 Preliminary

The principal sources of fugitive greenhouse gases from coal mining include emissions from underground and open cut mining activities and emissions from decommissioned mines. A small amount of emissions are also associated with flaring coal mine waste gas and post-mining activities such as from the stockpiling of coal. This chapter describes the methods for estimating emissions from each of these sources.

Other sources of emissions arising from the coal production process, such as from the combustion of fuels for energy (e.g. electricity production), are not described in this chapter and must be estimated using the Methods described in other chapters.

3.2 Outline of Part

This Part provides for fugitive emissions from coal mining, as follows:

(a) underground mining (see Division 3.2.2);

(b) open cut mining (see Division 3.2.3);

(c) decommissioned underground mines (see Division 3.2.4).

Division 3.2.2 Underground mines

Subdivision 3.2.2.1 Preliminary

Fugitive emissions from underground mines involve the release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata. Emissions also arise from post mining activities such as the stockpiling of coal from the release of residual gases within the coal not released during the mining process. Emissions also occur when coal mine waste gas is flared.

3.3 Application

This Division applies to fugitive emissions from underground mining activities (other than decommissioned underground mines).

3.4 Available methods

(1) Subject to section 1.18, estimating emissions released from underground mining activities (other than decommissioned underground mines) the following methods as set out in this section must be used.

Methane from extraction of coal

(2) Method 4 under section 3.6 must be used for estimating fugitive emissions of methane that result from the extraction of coal from the underground mine.

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

Carbon dioxide from extraction of coal

(3) Method 4 under section 3.6 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).

General

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

Summary of available methods, for estimating emissions from underground mines, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Underground mining activities			
Method 1	NA	NA	NO
Method 2, 3	NA	NA	NO
Method 4	Section 3.6	Section 3.6	NO
Post-mining Activities			
Method 1	NA	Section 3.17	NO
Methods 2, 3 and 4	NA	NA	NO
Flaring			
Method 1	Section 3.14	Section 3.14	Section 3.14
Method 2	Section 3.15	NA	NA

Method 3	Section 3.16	NA	NA
Method 4	NA	NA	NA
Venting			
Methods 1, 2 and 3	NA	NA	NO
Method 4	Part 1.3	Part 1.3	NO

NA = Not available. NO = Not occurring

Subdivision 3.2.2.2 Fugitive emissions from extraction of coal

3.6 Method 4 — extraction of coal

Method 4 for estimating emissions associated with underground mining operations involves directly measuring emissions within ventilation shafts and degasification systems. This Method is dealt with in detail in Part 1.3 of Chapter 1.

Estimation methods under current applicable state or territory legislation

In addition to the methods outlined in Part 1.3, Reporters may also directly measure emissions using periodic emissions measurement (PEM) in accordance with elements of relevant State Government legislation. This legislation includes the following:

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).

It is intended that, as a minimum, existing practices for the monitoring of gases at underground mines may be maintained as input into the emissions estimation process under Method 4.

(1) Method 4 is:

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

where:

$\boldsymbol{E_j}$ 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.

$\boldsymbol{CO_2\text{-}e_{\ j\ gen,\ total}}$ 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 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

This section describes how measurements of gas flow rates and concentrations are converted from volumetric flow rates to mass emission estimates.

(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.

Part 1.3 provides more details on estimating emissions from PEM systems.

3.8 Periodic emission measurement systems and equipment — Overview

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

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

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

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) 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

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

Method 1 describes how to estimate greenhouse gas emissions from the flaring of coal mine waste gas - by multiplying the quantity of coal mine waste gas flared by the energy content and emission factor for each gas type. The quantity of coal mine waste gas flared is estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from Division 2.3.2 in Chapter 2.

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 Table 2.3.2, 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 Table 2.3.2, measured in kilograms CO_2-e 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

Method 2 requires representative and unbiased samples of coal mine waste gas consumed and the analysis of the coal mine waste gas to determine gas composition and must be done in accordance with Australian or equivalent international standards.

(1) 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

Method 3 is the same as for Method 2 except that it requires samples to be obtained in accordance with Australian or equivalent international standards.

(1) 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

Most fugitive greenhouse gas emissions are released from coal during the mining process. However some residual gas remains trapped within the coal after extraction, and is slowly released during, handling, transportation and stockpiling of the coal.

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

Method 1 for estimating emissions from post-mining activities, with the source as described in IPCC 2006, is associated with gassy underground mines only.

The method is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. Emissions are estimated by multiplying a (physical) quantity of run-of-mine coal extracted by an emission factor.

It is intended that consideration will be given to the development of additional higher order methods for this source in future.

(1) Method 1 is:

$$E_j = Q \times EF_j$$

where:

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.

(2) ***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

Fugitive emissions from open cut mines involve the release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata. Emissions also occur when coal mine waste gas is flared or is vented during degasification of the coal seams prior to the commencement of coal extraction.

Subdivision 3.2.3.1 Preliminary

3.18 Application

This Division applies to 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 an open cut mine facility the methods 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).

General

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

Summary of available methods for estimating emissions from open cut mines, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Open cut mining activities			
Method 1	NA	Section 3.20	NO
Method 2	Section 3.21	Section 3.21	NO
Method 3	Section 3.26	Section 3.26	NO
Method 4	NA	NA	NO
Flaring			
Method 1	Section 3.27	Section 3.27	Section 3.27
Method 2	Section 3.28	NA	NA
Method 3	Section 3.29	NA	NA
Method 4	NA	NA	NA
Venting			
Methods 1, 2 and 3	NA	NA	NO
Method 4	Part 1.3	Part 1.3	NO

NA = Not available. NO = Not occurring

Subdivision 3.2.3.2 Fugitive emissions from extraction of coal

Method 1 for open cut mining operations associated with the extraction of coal is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. Emissions are estimated for a particular location of the mine by multiplying a (physical) quantity of run-of-mine coal extracted by an emission factor. Note that new factors have been adopted for some States in the *National Inventory Report 2006* as a result of the most recent international expert review process.

3.20 Method 1 — extraction of coal

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.

Example

A facility constituted by an open cut coal mine in NSW extracts 2,554,000 tonnes of run-of-mine coal during the year. The Reporter elects to use Method 1 (Section 3.20) to estimate fugitive emissions of methane. Emissions are estimated as follows:

$$E_j = Q \times EF_j$$

where:
E_j is the emissions of methane (j) released 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. In this case being 2,554,000 tonnes of raw coal.

EF_j is the emission factor for methane (j), measured in CO_2 e tonnes per tonne of raw coal extracted from the mine. In this case, for an open cut mine in NSW the emission factor is 0.045 tonnes CO_2-e per tonne of raw coal extracted.

Therefore, the estimate of methane emissions in CO_2-e tonnes:

E_j = (2,554,000 x 0.045)

Total emissions of methane = 114,930 t CO_2-e

3.21 Method 2 — extraction of coal

Method 2 for estimating emissions from open cut mining involves the estimation of a total stock of gas available for release as emissions from the mine extraction area.

The total stock of gas is determined by sampling coal and non-coal strata layers to analyse gas content of the area adjusted for past quantities of gas captured for combustion, flared or transferred off site. It is intended that these potential sources of emissions should be estimated and reported at the time they occur. As emissions from the operating mine are to be determined using a stock of gas approach, these estimated quantities of gas released from the mine extraction area prior to mining should be summed over time and deducted from the total stock of gas available for release at the time of mining.

The framework for this method is based on:

Saghafi, A. (2008), *Evaluating a tier 3 method for estimating fugitive emissions from open cut mining,* Joint Research Project ACARP (C15076) and CSIRO. CSIRO Investigation Report ET/IR 1011. This report can be obtained from: http://www.acarp.com.au/reports.aspx.

More specific components of the methods such as the sampling of coal seams and surrounding rock strata and measuring the gas contents of the coal and non-coal strata must be done in accordance with Australian, international or equivalent standards (see section 3.25 below). Additional relevant standards for the estimation and reporting of gas bearing strata (in particular layers of coal) include:

- *The Australian code for reporting of exploration results, mineral resources and ore reserves,* the Joint Ore Reserves Committee (JORC) Code, 2004 edition

- *Australian Guidelines for Estimating and Reporting of Inventory Coal, Coal Resources and Coal Reserves*, prepared by the Coalfields Geology Council of NSW and the Queensland Mining Council, 2003.

These industry standards can be obtained from: http://www.jorc.org.

(1) Method 2 is:

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

where:

$\boldsymbol{E_j}$ 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.

$\boldsymbol{\gamma_j}$ 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:

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

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

Measurement of the gas content from coal and other gas bearing strata layers requires use of borecores. Geological characteristics can help to identify possible gas bearing areas based on previous evidence of gas content in a region and to infer gas content of coal and rock strata between actual borecore measurements. However knowledge of geological characteristics of a site, with no specific borecore measurements, would not be able to adequately predict gas content (Saghafi, 2008).

Gas content can be measured using either a slow desorption or a fast desorption method. Both methods follow similar steps, however the time of the procedure in the fast desorption method is significantly reduced by crushing coal before it naturally desorbs its gas. Because gases are released much more slowly using the slow desorption method, costs of undertaking the analyses can be significantly higher than the fast desorption method (Saghafi, 2008).

Analysis of gas content in strata layers 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*.

Apart from gas content of each strata layer, the thickness, length and density of each strata layer also has to be ascertained in order to work out the total mass of each gas bearing strata layer. The analysis of each strata layer must be done in accordance with an appropriate standard.

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*.

The Australian code for reporting of exploration results, mineral resources and ore reserves. The Joint Ore Reserves Committee (JORC) Code, 2004 edition

Australian Guidelines for Estimating and Reporting of Inventory Coal, Coal Resources and Coal Reserves. Prepared by the Coalfields Geology Council of NSW and the Queensland Mining Council, 2003.

3.26 Method 3 — extraction of coal

(1) Method 3 is the same as for Method 2 in section 3.21, except samples must be obtained using an appropriate standard, rather than general sampling requirements outlined in section 3.24.

(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

Emissions using Method 1 are estimated by multiplying the quantity of gas flared by the energy content and emission factor for each gas type. The quantity of gas flared is estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from Division 2.3.2 of Chapter 2.

(1) 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

Method 2 is the same as method 2 under section 3.15. Method 2 requires representative and unbiased samples of coal mine waste gas consumed and analysis of the coal mine waste gas to determine gas composition and must be done in accordance with Australian or equivalent international standards and as set out for Division 2.3.3.

3.29 Method 3 — coal mine waste gas flared

Method 3 is the same as for Method 2 except that it requires samples to be obtained in accordance with Australian or equivalent international standards and as set out in Division 2.3.4.

Division 3.2.4 Decommissioned underground mines

Greenhouse gas emissions are known to occur following the closure of coal mines. Leakages to the atmosphere occur through fractured rock strata, open vents and seals over daily to decadal timescales. However, emissions will be reduced by flooding of the mine, which prevents desorption of gases from the remaining coal strata and non-coal strata layers in the closed mine.

Subdivision 3.2.4.1 Preliminary

3.30 Application

This Division applies to 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 from 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 emissions another method may be used that is consistent with the principles in section 1.13.

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

Summary of available methods for estimating emissions from decommissioned mines, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Underground decommissioned mines			
Method 1	NA	Section 3.32	NO
Methods 2, 3	NA	NA	NO
Method 4	Section 3.37	Section 3.37	NO
Flaring			
Method 1	Section 3.38	Section 3.38	Section 3.38
Method 2	Section 3.39	NA	NA
Method 3	Section 3.40	NA	NA
Method 4	NA	NA	NA

NA = Not available. NO = Not occurring

Subdivision 3.2.4.2 Fugitive emissions from decommissioned underground mines

3.32 Method 1 — decommissioned underground mines

Method 1 for emissions from decommissioned mines is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*.

(1) Method 1 for emissions from decommissioned mines is:

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

where:

$\boldsymbol{E_{dm}}$ is the fugitive emissions of methane from the mine during the year measured in CO_2-e tonnes.

$\boldsymbol{E_{tdm}}$ 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.

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

$\boldsymbol{F_{dm}}$ 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

The emission factor for Method 1 is derived from an emission decay curve (EDC). The EDC describes the decline in fugitive methane emissions overtime following mine closure. Hyperbolic curves have been found to function best in portraying the rapid decline in emissions in the first few years, followed by a slow decline over time of the remaining emissions (*National Inventory Report 2006*).

Australian-specific EDCs developed for the national inventory have being utilized for both gassy and non-gassy mines.

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

$$(1 + A\,T)^{b}\,C$$

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

Emissions from decommissioned mines are reduced as a mine floods due to the reduction of gas desorption from the coal remaining in the closed mine. The variables required to estimate the portion of the mine flooded at a point in time is the size of the void volume and the water inflow rate into the closed mine.

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.

Examples of techniques available for measuring rate of inflow include air-lift pumping and V-notch weir, or container filling time.

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

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.

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.

For example, the mine plan showing longwall and roadway geometry maybe used to estimate the void volume size.

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) 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

Emissions using Method 1 are estimated by multiplying the quantity of gas flared by the energy content and emission factor for the coal mine waste gas. The quantity of coal mine waste gas flared should be estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from Division 2.3.2 of Chapter 2.

(1) 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

Method 2 is the same as method 2 under section 3.15.

Method 2 requires representative and unbiased samples of coal mine waste gas consumed and analysis of the coal mine waste gas to determine gas composition and must be done in accordance with Australian or equivalent international standards and as set out for Division 2.3.3.

3.40 Method 3 — coal mine waste gas flared

Method 3 is the same as for Method 2 except that it requires samples to be obtained in accordance with Australian or equivalent international standards and as set out in Division 2.3.4

3.40A Reporting

The corporation's report must include information for the facility in relation to greenhouse gas emissions from the source during the year and must identify:

(a) the methods used by the corporation to estimate the greenhouse gas emissions from the source; and

(b) the amount of each greenhouse gas that is emitted.

Additional emissions-related information set out in the Regulations, should also be reported.

For the reporting of all other scope 1 emission sources, Reporters should refer to chapters 2, 4 and 5 and other parts of this chapter.

Part 3.3 Oil or gas — fugitive emissions

Division 3.3.1 Preliminary

This part includes fugitive emissions from exploration, production, transport, storage, processing and refining of oil or gas.

Other sources of emissions arising from the production processes, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

3.40A Definition of natural gas for Part 3.3

In this Part:

natural gas includes coal seam methane that is captured for combustion where the production of coal is not intended to occur.

3.41 Outline of Part

This Part provides for fugitive emissions from the following:

(a) oil or gas exploration (see Division 3.3.2);
(b) crude oil production (see Division 3.3.3);
(c) crude oil transport (see Division 3.3.4);
(d) crude oil refining (see Division 3.3.5);
(e) natural gas production or processing, other than emissions that are vented or flared (see Division 3.3.6);
(f) natural gas transmission (see Division 3.3.7);
(g) natural gas distribution (see Division 3.3.8);
(h) natural gas production or processing, emissions that are vented or flared (see Division 3.3.9).

Division 3.3.2 Oil or gas exploration

Emissions may occur during the process of drilling for oil or gas either during exploration or development drilling whenever gas or liquid hydrocarbons are encountered. CO_2, some unburnt methane and N_2O are released as a result of the flaring of oil or gas. Emissions may also occur as a result of leakages and accidental releases such as blowouts.

3.42 Application

This Division applies to fugitive emissions from flaring from oil or gas exploration activities, including emissions from:

(a) oil well drilling; and

(b) gas well drilling; and

(c) drill stem testing; and

(d) well completions.

3.43 Available methods

Methods 1, 2 and 3 are set out below for the estimation of emissions from flaring of fuel. Flaring is the combustion of fuels for non-productive (non-commercial) reasons –for example for health and safety reasons. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2 and the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004.*

(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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from oil and gas exploration, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 3.44	Section 3.44	Section 3.44
Method 2	Section 3.45	Section 3.45	NA
Method 3	Section 3.46	NA	NA
Method 4	NA	NA	NA

NA = Not available.

3.44 Method 1 — oil or gas exploration

Method 1 for oil exploration and gas exploration is derived from the *National Greenhouse Accounts*.

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***) from a fuel type (***i***) flared in the oil or gas exploration during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) flared in the oil or gas exploration 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 the fuel type (***i***) flared.

(2) For $\boldsymbol{EF_{ij}}$ 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 or gas exploration

(1) Method 2 is the same as method 1 but the carbon dioxide emission factor $\boldsymbol{EF_{ij}}$ 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 or 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

Emissions arise for this category from fugitive sources (for example gas leaks, accidental releases), storage losses and from flaring of fuels (that is, the combustion of fuels for non-productive or non-commercial reasons) – for example for health and safety reasons.

Subdivision 3.3.3.1 Preliminary

3.47 Application

(1) This Division applies to fugitive emissions from crude oil production activities, including emissions from flaring, from:

(a) the oil wellhead; and

(b) well servicing; and

(c) oil sands mining; and

(d) shale oil mining; and

(e) the transportation of untreated production to treating or extraction plants; and

(f) activities at extraction plants or heavy oil upgrading plants, and gas re-injection systems and produced water disposal systems associated with the those plants; and

(g) activities at upgrading plants and associated gas re-injection systems and produced water disposal systems.

(2) For paragraph (1) (e), ***untreated production*** includes:

(a) well effluent; and

(b) emulsion; and

(c) oil shale; and

(d) oil sands.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from crude oil production (non-flared), by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	NO	Section 3.49	NO
Method 2	NO	Section 3.50	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

NA = Not available. NO = Not occurring

3.49 Method 1 — crude oil production (non-flared) emissions of methane

Method 1 for crude oil production for fugitive emissions is derived from the *National Greenhouse Accounts*.

(1) Method 1 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)\ ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from the crude oil production 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 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.

$\boldsymbol{Q_{ik}}$ 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

Method 2 requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004*, sections 5 and 6.1.2.

(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.

$\boldsymbol{EF_{ijk}}$ 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 $\boldsymbol{EF_{ijk}}$, 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

Methods 1, 2 and 3 are provided for flaring of fuels. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2 and the API *Compendium*.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Available methods, for estimating emissions from crude oil production (flared), by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 3.52	Section 3.55	Section 3.55
Method 2	Section 3.53	Section 3.56	NA
Method 3	Section 3.54	NA	NA
Method 4	NA	NA	NA

NA = Not available. NO = Not occurring

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:

$\boldsymbol{E_{ij}}$ 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.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) measured in tonnes flared in crude oil production during the year.

$\boldsymbol{EF_{ij}}$ 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 $\boldsymbol{EF_{ij}}$ 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 $\boldsymbol{EF_{ij}}$ 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.

Example

A crude oil production platform has a throughput of 710,400 tonnes of crude oil during the year. It has an equipment type constituting a floating tank in which 685,000 tonnes of crude oil throughput occurred during the year. 400 tonnes of crude oil were flared during the year.

The Reporter elects to use Method 1 to calculate fugitive emissions from crude oil production and flaring, for each of the greenhouse emission gases (*j*) (carbon dioxide, methane and nitrous oxide). Emissions are estimated as follows:

Part A: Crude oil production (non flared component)

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)\,ij}$$

where:

E_{ij} is the emissions measured in CO_2 e tonnes of methane (j), released from the crude oil production during the year.

Σ_k is the sum of emissions of methane (j) (tonnes of CO_2-e) arising from equipment of types (k) listed in the table in section 3.49.

Q_{ik} is the total of the quantities of crude oil (tonnes) that pass through each equipment of type (k) listed in the table in section 3.49 . **In this case it is the crude oil throughput for the floating tank is 685,000 tonnes**.

EF_{ijk} is the emission factor for methane (j) measured as tonnes of CO_2-e per tonne of crude oil that passes through each equipment of type (k). **In this case the emission factor for the floating tank is 3.2 x 10^{-6} CO_2-e/tonnes fuel throughput.**

Q_i is the total quantity of crude oil (i) measured in tonnes of crude oil production. **In this case the crude oil production throughput is 710,400 tonnes**.

$EF_{(l)\,ij}$ **1.2 x 10^{-3}**, 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 production.

Therefore, the estimate of methane emissions in CO_2-e tonnes :

$$= (685{,}000 \times 3.2 \times 10^{-6}) + (710{,}400 \times 1.2 \times 10^{-3})$$

Total emissions of methane = 855 t CO_2-e

Part B: Crude oil production (flared component)

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions of gas type (j) (CO_2-e tonnes) released from a fuel type (i) flared.

Q_i is the quantity of fuel type flared (i) (tonnes). **In this case the quantity of crude oil flared is 400 tonnes**.

EF_{ij} is the emission factor for gas type (j) in tonnes of CO_2-e emissions per tonne of the fuel type (i) flared. **The emission factors are obtained from Method 1, section 3.52**

Therefore, the estimate of greenhouse gas emissions (from carbon dioxide, methane and nitrous oxide (j)) in CO_2-e tonnes:

For carbon dioxide

$$=400 \times 3.2$$

Total emissions of carbon dioxide = 1280 t CO_2-e

For methane

$$=400 \times 0.007$$

Total emissions of methane = 3 t CO_2-e

For nitrous oxide

=400 x 0.07
Total emissions of nitrous oxide = 28 t CO_2-e

Division 3.3.4 Crude oil transport

The crude oil transport subsector includes fugitive methane emissions associated with the marine, road and rail transport of crude oil. Emissions result largely from three types of activities: loading, transit, and ballasting.

3.57 Application

This Division applies to fugitive emissions from crude oil transport activities, other than emissions that are flared.

Note that Appendix B has the following definition for crude oil transport:

crude oil transport means the transportation of marketable crude oil to heavy oil upgraders and refineries by means that include the following:

(a) pipelines;
(b) marine tankers;
(c) tank trucks;
(d) rail cars.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Available methods, for estimating emissions from crude oil transport), by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	NO	Section 3.59	NO
Method 2	NO	Section 3.60	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

NA = Not available. NO = Not occurring

3.59 Method 1 — crude oil transport

Method 1 for crude oil transport for fugitive emissions is derived from the *National Greenhouse Accounts*.

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 x 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

Method 2 requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004* sections 5 and 6.1.2.

(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

Emissions arise for this category from fugitive sources (for example gas leaks), flaring and from the process vents, system upsets and accidents, including the combustion of catalyst coke for non-energy purposes.

Other sources of emissions arising from the crude oil refining, such as from the combustion of fuels for energy or from the production of hydrogen, are not described in this chapter and must be estimated using the Methods described in other chapters.

3.61 Application

This Division applies to fugitive emissions from crude oil refining activities, including emissions from flaring at petroleum refineries.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from crude oil refining, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Crude oil refining and storage tanks			
Method 1	NO	Section 3.63	NO
Method 2	NO	Section 3.64	NO
Methods 3, 4	NO	NA	NO
Process vents, system upsets and accidents			
Method 1	Section 3.65	Section 3.65	Section 3.65

Methods 2, 3	NA	NA	NA
Method 4	Section 3.66	Section 3.66	Section 3.66
Flaring			
Method 1	Section 3.67	Section 3.67	Section 3.67
Method 2	Section 3.68	Section 3.68	NA
Method 3	Section 3.69	NA	NA
Method 4	NA	NA	NA

NA = Not available. NO = Not occurring

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 for fugitive emissions from crude oil refining is derived from the *National Greenhouse Accounts*.

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.

$\sum_I$ 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

Method 2 for fugitive emissions from crude oil refining requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004* sections 5 and 6.1.2.

(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.

$\boldsymbol{Q_{ik}}$ 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 refining and in the storage tanks.

$\boldsymbol{EF_{ijk}}$ 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 $\boldsymbol{EF_{ijk}}$, 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 for the estimation of emissions from the burning of catalyst coke for non-energy purposes is derived from the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004* sections 5.2.

It is intended that there should be no double count or omissions of emissions from the estimation of emissions from the combustion of the catalyst coke. Where it is difficult to distinguish between the emissions from combustion of catalyst coke for non-energy purposes from its use as an energy source, it is intended that all emissions should be attributed to the combustion of fuels for energy.

Method 1 is:

$$E_i = Q_i \times CCF_i \times 3.664$$

where:

E_i is the fugitive emissions of carbon dioxide 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

Method 4 is provided as an additional option and is taken from the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004* sections 5 and 6.1.2. Consistent with the American Petroleum Institute methodology, emissions of carbon monoxide must be treated as if they fully oxidise to carbon dioxide and estimated accordingly.

(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

Flares are commonly used at refineries for the disposal of vented waste gases. The flaring of refinery gases results in the emission of CO_2, methane, nitrous oxide and products of incomplete combustion. Method 1 is derived from the methods used for the National Greenhouse Accounts. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2.

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 or processing (other than emissions that are vented or flared)

Emissions of methane may occur during natural gas production—during production or field processing—from the same causes as the corresponding emissions from crude oil production, namely leakage, accidents and controlled releases for safety purposes and during some maintenance operations. Venting of CO_2 extracted from raw gas and flaring of unusable gas produced at various stages of processing are separately accounted for under venting and flaring.

Other sources of emissions arising from natural gas production and processing, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Note that in this part the definition of natural gas is as follows:

> ***natural gas*** includes coal seam methane that is captured for combustion where the production of coal is not intended to occur

3.70 Application

(1) This Division applies to fugitive emissions from natural gas production or processing activities, other than emissions that are vented or flared, including emissions from:

(a) a gas wellhead through to the inlet of gas processing plants; and

(b) a gas wellhead through to the tie-in points on gas transmission systems, if processing of natural gas is not required; and

(c) gas processing facilities; and

(d) well servicing; and

(e) gas gathering; and

(f) gas processing and associated waste water disposal and acid gas disposal activities.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from natural gas production and processing (other than emissions that are vented or flared), by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	NO	Section 3.72	NO
Method 2	NO	Section 3.73	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

NA = Not available. NO = Not occurring

3.72 Method 1 — natural gas production or processing (other than emissions that are vented or flared)

Method 1 for fugitive emissions from natural gas production and processing is derived from the *National Greenhouse Accounts*.

(1) Method 1 is:

$$E_{ij} = \Sigma_k \ (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)\ ij}$$

where:

$\boldsymbol{E_{ij}}$ 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.

$\boldsymbol{\Sigma_k}$ 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.

$\boldsymbol{Q_{ik}}$ 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.

$\boldsymbol{EF_{ijk}}$ 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.

$\boldsymbol{Q_i}$ is the total quantity of natural gas (***i***) that passes through the natural gas production and processing measured in tonnes.

$\boldsymbol{EF_{(l)\ ij}}$ 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 $\boldsymbol{EF_{ijk}}$ 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 or processing (other than venting and flaring)

Method 2 for fugitive emissions from natural gas production and processing requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004 sections 5 and 6.1.2.

(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 natural gas production and processing during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ 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.

$\boldsymbol{Q_{ik}}$ 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.

$\boldsymbol{EF_{ijk}}$ 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 $\boldsymbol{EF_{ijk}}$, 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

Emissions may occur as a result of compressor blow downs for maintenance at compressor stations, maintenance on pipelines, leakage and accidents.

Transmission mains are defined as high-pressure pipelines greater than 1050 kilopascals, as used in the Energy Supply Association of Australia natural gas statistics.

Note that in this part the definition of natural gas is as follows:

> ***natural gas*** includes coal seam methane that is captured for combustion where the production of coal is not intended to occur

3.74 Application

This Division applies to fugitive emissions from natural gas transmission activities.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from natural gas transmission, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 3.76	Section 3.76	NO
Method 2	Section 3.77	Section 3.77	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

NA = Not available. NO = Not occurring

3.76 Method 1 — natural gas transmission

Method 1 for fugitive emissions from natural gas transmission is derived from the *National Greenhouse Accounts*.

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***).

Example

A company has a network of natural gas transmission pipelines with a total length of 3600 km, over a year. The Reporter elects to use Method 1 to calculate fugitive emissions from natural gas transmission, for carbon dioxide and methane. Emissions are estimated as follows:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions measured in CO_2 e tonnes of gas type (j), being either carbon dioxide or methane, released 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. **In this case pipeline length is 3600 km**.

EF_{ij} is the emission factor for gas type (j) being 0.02 for carbon dioxide and 8.7 for methane measured in tonnes of CO_2 e emissions per kilometre of pipeline (i).

Therefore, to estimate greenhouse gas emissions (from carbon dioxide and methane) in CO_2-e tonnes:

For carbon dioxide

=3600 x 0.02

Total emissions of carbon dioxide = 72 t CO_2-e

For methane

=3600 x 8.7

Total emissions of methane = 31,320 t CO_2-e

3.77 Method 2 — natural gas transmission

Method 2 for fugitive emissions from natural gas transmission requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004* sections 5 and 6.1.2. The option is also provided to refine the emission factors from information on the composition of the gases and from information on the leakage rates for specific pipeline materials for the industry.

(1) Method 2 is:

$$E_j = \Sigma_k \ (Q_k \times EF_{jk})$$

where:

$\boldsymbol{E_j}$ 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.

$\boldsymbol{\Sigma_k}$ 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.

$\boldsymbol{Q}_k$ 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.

$\boldsymbol{EF_{jk}}$ 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 $\boldsymbol{EF_{jk}}$, 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

Emissions arise for this category from fugitive sources (for example gas leaks, accidental releases). The boundary between natural gas transmission and distribution is generally taken to be the city gate regulator stations at which gas pressures are reduced from transmission pressures to sub-transmission pressures. For the purposes of this methodology, natural gas distribution comprises low, medium and high-pressure reticulation ≤ 1050 kilopascals.

Other sources of emissions arising from the natural gas distribution, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Note that in this part the definition of natural gas is as follows:

> ***natural gas*** includes coal seam methane that is captured for combustion where the production of coal is not intended to occur

3.78 Application

This Division applies to fugitive emissions from natural gas distribution activities.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from natural gas distribution, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 3.80	Section 3.80	NO
Method 2	Section 3.81	Section 3.81	NO
Method 3	NA	NA	NO
Method 4	NA	NA	NO

NA = Not available. NO = Not occurring

3.80 Method 1 — natural gas distribution

Method 1 for fugitive emissions from natural gas distribution is derived from the *National Greenhouse Accounts*.

(1) Method 1 is:

$$E_{ij} = S_p \times \%UAG_p \times 0.55 \times C_{i,p,j}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***) that result from natural gas distribution through a system of pipelines with sales of gas ($\boldsymbol{S_p}$) during the year, measured in CO_2-e tonnes.

$\boldsymbol{S_p}$ is the total gas sales during the year from the pipeline system measured in terajoules.

$\boldsymbol{\%UAG_p}$ 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 $\boldsymbol{\%UAG_p}$ in method 1 represents the proportion of gas that is unaccounted for and released as emissions.

$\boldsymbol{C_{i,p,j}}$ 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 $\boldsymbol{C_{i,p,j}}$ 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
6	TAS	0.40	0.9	326
7	NT	0.10	0.0	264

3.81 Method 2 — natural gas distribution

Method 2 for fugitive emissions from natural gas distribution requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004* sections 5 and 6.1.2. The option is also provided to refine the emission factors from information on the composition of the gases and from information on the leakage rates for specific pipeline materials for the industry.

(1) Method 2 is:

$$E_j = \Sigma_k \ (Q_k \times EF_{jk})$$

where:

$\boldsymbol{E_j}$ is the fugitive emissions of gas type (***j***) that result from the natural gas distribution during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ 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.

$\boldsymbol{Q}_k$ 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.

$\boldsymbol{EF_{jk}}$ 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 $\boldsymbol{EF_{jk}}$, 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 using adjusted factors; or

(d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type — those factors.

(3) In paragraph 3.81 (2) (c), a reference to ***factors adjusted*** is a reference to the factors in Table 5-3 of the publication entitled *Greenhouse Gas Emission Estimation Methodologies, Procedures and Guidelines for the Natural Gas Distribution Sector*, American Gas Association, April 2008, that are adjusted for variations in estimated gas composition in accordance with:

(a) section 5.2.1 of that publication; and

(b) Division 2.3.3.

Note that 3.81 (2) (c) allows adjustment of emission factors for variations in the type of material from which the equipment is made. This adjustment is made using Table 5-3 and section 5.2.1 of the publication entitled Greenhouse Gas Emission Estimation Methodologies, Procedures and Guidelines for the Natural Gas Distribution Sector, American Gas Association, April 2008. Table 5-3 includes the emission factors for equipment made from different materials, for example, cast iron pipelines or plastic pipelines. Section 5.2.1 provides a description of how to apply the information in Table 5-3.

The publication entitled Greenhouse Gas Emission Estimation Methodologies, Procedures and Guidelines for the Natural Gas Distribution Sector, American Gas Association, April 2008, is available from:
http://www.aga.org/legislative/legislative+advocacy/environmentalinformation/publicenviro/2008/aga+greenhouse+gas+emission+estimation+guidelines+for+the+natural+gas+distribution+sector.htm

Division 3.3.9 Natural gas production or processing (emissions that are vented or flared)

3.82 Application

This Division applies to fugitive emissions from venting or flaring from natural gas production or processing activities, including emissions from:

(a) the venting of natural gas; and

(b) the venting of waste gas and vapour streams at facilities that are constituted by natural gas production or processing; and

(c) the flaring of natural gas and waste gas and waste vapour streams at those facilities.

Note that in this part the definition of natural gas is as follows:

natural gas includes coal seam methane that is captured for combustion where the production of coal is not intended to occur

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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from natural gas production and processing (emissions that are vented or flared), by emissions of gas type (j)

	CO_2	CH_4	N_2O
Deliberate releases from process vents, system upsets and accidents			
Method 1	Section 3.84	Section 3.84	NO
Method 2	NA	NA	NO
Method 3	NA	NA	NO
Method 4	Method 4 under Part 1.3	Method 4 under Part 1.3	NO
Flaring			
Method 1	Section 3.85	Section 3.85	Section 3.85
Method 2	Section 3.86	Section 3.85	NA
Method 3	Section 3.87	NA	NA

NA = Not available. NO = Not occurring

Subdivision 3.3.9.1 Fugitive emissions that result from deliberate releases from process vents, system upsets and accidents

Venting refers to the controlled release of unburnt gases to the atmosphere. Venting at oil or gas processing facilities is mainly associated with the release of CO_2, which is extracted from the raw gas stream in the course of gas processing. Because separation of the other components of the gas stream from the CO_2 is incomplete, the vented CO_2 contains small quantities of methane. The quantities of CO_2 and methane vented will depend on the concentration of CO_2 in the raw gas, which varies significantly between gas fields, and on the mode of operation and efficiency of the CO_2 stripping plant. The volumes of the vent gas and CO_2 and methane concentrations are monitored as a part of routine plant operation.

3.84 Method 1 — deliberate releases from process vents, system upsets and accidents

Method 1 for vented emissions from natural gas production and processing is intended to be as specified in the American Petroleum Institute's Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004 sections 5 and 6.1.2.

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

Flaring refers to the controlled release to combustion of a mixed flammable gas stream. At gas processing plants, flared gas may arise from natural gas processing. Where there is no market for gas separated from the wellhead production stream, the gas is reinjected or flared.

This subsector does not include flaring from petroleum refining activities, which should be reported separately under 1.B.2a.iv Crude Oil refining and storage.

Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 for carbon dioxide rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2. Method 2 for methane emissions should be estimated in accordance with the guidance set out in the American Petroleum Institute's *Compendium*.

3.85 Method 1 — gas flared from natural gas production and processing

(1) Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ 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.

$\boldsymbol{Q_i}$ is the quantity measured in tonnes of gas flared during the year.

$\boldsymbol{EF_{ij}}$ 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 $\boldsymbol{EF_{ij}}$ 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 ($\boldsymbol{EF}_{ij}$) 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.

3.87 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.

3.87A Reporting

The corporation's report must include information for the facility in relation to greenhouse gas emissions from the source during the year and must identify:

(a) the criteria used by the corporation to estimate the amount of fuel produced or consumed for the source.

(b) the methods used by the corporation to estimate the greenhouse gas emissions from the source.

(c) the amount of each greenhouse gas that is emitted.

Additional emissions-related information set out in Regulation 4.11, should also be reported.

For the reporting of all other scope 1 emission sources, Reporters should refer to chapters 2, 4 and 5 and other parts of this chapter.

Part 3.4 Carbon Capture and Storage

Carbon dioxide capture and storage (CCS) is a technology aimed at reducing greenhouse gas emissions from burning fossil fuels during industrial and energy-related processes.

No methods have been described in these Technical Guidelines for the estimation of emissions from carbon capture and storage. Potential sources of emissions should be monitored in accordance with relevant Australian Government and State legislation, regulations or guidance. CCS consists of the following four components:

1. Capture—carbon dioxide gases arising from the combustion of fuels and certain industrial processes can be captured to produce a concentrated stream of CO_2 at high pressure. Only CO_2 captured for permanent storage in geological reservoirs should be estimated.

2. Transportation—compressed CO_2 may be transported from the source to a storage site through pipelines or in tanks carried by ships.

3. Injection—the injection of CO_2 requires the use of a number of surface facilities including storage facilities, any distribution manifold at the end of the pipeline, distribution pipelines to the wells, additional compression facilities, measurement and control systems, wellhead(s) and the injection wells.

4. Storage—involves the long-term isolation of captured CO_2 from the atmosphere (IPCC 2006). CO_2 can be stored in geological formations such as deep saline formations, depleted or partially depleted oil and natural gas fields, and coal seams.

Fugitive emissions may arise at each stage of the process.

Fugitive emissions may arise from the leakage of CO_2 due to pipeline breaks, seals and valves, intermediate compressor stations on pipelines, intermediate storage facilities, ships transporting low temperature liquefied CO_2 and ship loading and offloading facilities.

Potential pathways for leakages from storage include, among others:

- operational or decommissioned wells;
- well blow-outs;

- future mining of CO_2 reservoirs;
- the pore system in low permeability cap rocks if the capillary entry pressure is exceeded or the CO_2 is in solution;
- situations in which the cap rock is locally absent;
- a spill if the reservoir is overfilled;
- dissolution of CO_2 into pore fluid and subsequent transport out of the storage site by natural fluid flow;
- natural or induced faults or fractures;
- fugitive methane emissions arising from the displacement of methane by CO_2 at geological storage sites.

Technical standards relating to the measurement of gases are set out in Chapter 2. These standards are applicable to the capture, transport and injection of gases.

For any oil or gas facility that captures carbon dioxide for permanent storage that would have otherwise been vented then emission estimates automatically take account of this quantity of gas captured. For other facilities it is intended that additional guidelines will be developed to improve the integration of this data with the other parts of a corporation's inventory in future.

3.4.1 Reporting

Reporters involved in carbon capture and storage should report the information listed in table in Regulation 4.12.

Chapter 4 Industrial processes emissions

Part 4.1 Preliminary

Industrial process emissions are an important source of emissions in Australia and are generated from a wide variety of activities. The principal processes that lead to industrial process emissions include:

1. Mineral Products—generated mainly from the consumption (heating) of carbonate materials (such as limestone) and from within processes that generate carbon dioxide from the use of carbonates;

2. Chemical Industry—generated mainly by the use of fuels as a feedstock or reductant;

3. Metal Products—generated principally from the use of fuels such as coke as carbon reductants and also including perfluorocarbons released from aluminium metal production;

4. Synthetic gas emissions —the release of hydrofluorocarbons and sulphur hexafluoride either as fugitive emissions or leakages from the use of these gases as (for example) refrigerants.

Other sources of emissions released in the course of the production, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Full details of industries covered in this chapter are given in section 4.1.

4.1 Outline of Chapter

(1) This Chapter provides for emissions from:
  (a) the consumption of carbonates; or
  (b) the use of fuels as:
    (i) feedstock; or
    (ii) carbon reductants;
  from sources that are industrial processes mentioned in subsection (2).

(2) For subsection (1), the industrial processes are as follows:

(a) in Part 4.2:
  (i) producing cement clinker (see Division 4.2.1); or
  (ii) producing lime (see Division 4.2.2); or
  (iii) using and producing soda ash (see Division 4.2.4); or
  (iv) using carbonate for the production of a product other than cement clinker, lime or soda ash (see Division 4.2.3); or

(b) in Part 4.3 — the production of:
  (i) ammonia (see Division 4.3.1); or
  (ii) nitric acid (see Division 4.3.2); or
  (iii) adipic acid (see Division 4.3.3); or
  (iv) carbide (see Division 4.3.4); or
  (v) a chemical or mineral product other than carbide using a carbon reductant (see Division 4.3.5);

(c) in Part 4.4 — the production of:
  (i) iron and steel (see Division 4.4.1); or
  (ii) ferroalloy metal (see Division 4.4.2); or
  (iii) aluminium (see Divisions 4.4.3 and 4.4.4); or
  (iv) other metals (see 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.

(4) This Chapter does not apply to emissions from fuel combusted for energy production.

Part 4.2 Industrial processes — mineral products

This Part applies to any industry that generates emissions of carbon dioxide through the consumption of carbonates such as calcium carbonate (limestone) or magnesium carbonate. The consumption of carbonates that does not lead to carbon dioxide emissions (for example, when used as gravel) is not covered by the scope of these Guidelines.

Division 4.2.1 Cement clinker production

Carbon dioxide is generated during the production of clinker, an intermediate product from which cement is made. The manufacture of cement involves a multi-stage process whereby calcium carbonate ($CaCO_3$) from calcium rich raw materials such as limestone, chalk and natural cement rock is heated at temperatures of approximately 1500 °C in cement kilns to form lime (CaO) and CO_2. In addition to $CaCO_3$, the raw materials used in cement production may also contain small quantities of magnesium carbonate ($MgCO_3$). On heating, $MgCO_3$ also decomposes to generate CO_2. Some clinker manufacturers also use materials containing lime and magnesium oxide as inputs into their process which can reduce the amount of CO_2 generated by that facility.

It is intended that the parameters F_{cal} and F_{ckd} in methods 1,2 and 3 in this division, be estimated by industry based on the principles of Section 1.13, namely transparency, comparability, accuracy and completeness. Where actual data for these is not available it is assumed that, at the temperatures and residence times achieved in cement (clinker) kilns, the degree of calcination achieved for all material incorporated in the clinker is 100 percent.

4.2 Application

This Division applies to 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 emissions, another method may be used that is consistent with the principles in section 1.13; *namely that the estimates are transparent, comparable, accurate and complete*.

Summary of available methods, for estimating emissions from cement production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.4	NO	NO
Method 2	Section 4.5	NO	NO
Method 3	Section 4.8	NO	NO
Method 4	Part 1.3	NO	NO

NO = Not occurring

4.4 Method 1 — cement clinker production

Method 1 for the production of cement clinker is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. It involves the collection of data on the quantities of cement clinker and cement kiln dust produced and the use of the specified emission factors for cement clinker and carbon-bearing non-fuel raw material.

Method 1 is:

$$E_{ij} = \left(EF_{ij} + EF_{toc,j}\right) \times \left(A_i + A_{ckd} \times F_{ckd}\right)$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide (***j***) released from the production of cement clinker (***i***) during the year measured in CO_2-e tonnes.

$\boldsymbol{EF_{ij}}$ 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.

$\boldsymbol{EF_{toc,j}}$ 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.

$\boldsymbol{A_i}$ is the quantity of cement clinker (***i***) produced during the year measured in tonnes and estimated under Division 4.2.5.

$\boldsymbol{A_{ckd}}$ 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.

$\boldsymbol{F_{ckd}}$ 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

Method 2 requires the derivation of more accurate, facility-specific emission factors to generate more accurate estimates of emissions of carbon dioxide from the production process. It utilises sampling and analysis of the clinker outputs to estimate the composition of its contents and, from an understanding of the chemical reactions involved in the calcination, the derivation of facility-specific emission factors. The fractions of calcium oxide and magnesium oxide in subsection (2) should not include the calcium oxide and magnesium oxide that enters the process in the raw materials..

(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, $\boldsymbol{EF_{ij}}$ is taken to be:

$$F_{CaO} \times 0.785 + F_{MgO} \times 1.092$$

where:

$\boldsymbol{F_{CaO}}$ is the estimated fraction of cement clinker that is calcium oxide derived from carbonate sources and produced from the operation of the facility.

$\boldsymbol{F_{MgO}}$ is the estimated fraction of cement clinker that is magnesium oxide derived from carbonate sources and produced from the operation of the facility.

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

Method 3 is based on the Tier 3 approach in the *2006 IPCC Guidelines for National Greenhouse Inventories* which utilises information on the purity of the carbonate inputs. This method requires sampling and analysis of the raw materials to determine the qualities that affect emission levels such as the raw material's pure carbonate content.

(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:

$\boldsymbol{E_{ij}}$ 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.

$\boldsymbol{EF_{ij}}$ 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.

$\boldsymbol{Q_i}$ 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.

$\boldsymbol{F_{cal}}$ 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.

$\boldsymbol{A_{ckd}}$ 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.

$\boldsymbol{EF_{ckd}}$ is 0.440, which is the carbon dioxide emission factor for calcined cement kiln dust lost from the kiln.

$\boldsymbol{F_{ckd}}$ 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.

$\boldsymbol{Q_{toc}}$ 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.

$\boldsymbol{EF_{toc}}$ 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 $\boldsymbol{EF_{ckd}}$ 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 $\boldsymbol{Q_{toc}}$ 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

Lime is a chemical having major uses in metallurgy and construction. Lime is produced by heating carbonate raw materials in a kiln. During this process, carbon dioxide is emitted. Emissions from the in-house production of lime in the metals industry is estimated under Division 4.2.3.

4.11 Application

This Division applies to lime production (other than the in-house production of lime in the 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 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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from lime production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.13	NO	NO
Method 2	Section 4.14	NO	NO
Method 3	Section 4.17	NO	NO
Method 4	Part 1.3	NO	NO

NO = Not occurring

4.13 Method 1 — lime production

Method 1 for the production of lime is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. It involves the multiplication of the quantity of lime produced by the emission factor for lime.

Method 1 is:

$$E_{ij} = A_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide (***j***) released from the production of lime (***i***) during the year measured in CO_2-e tonnes.

$\boldsymbol{A_i}$ is the quantity of lime produced during the year measured in tonnes and estimated under Division 4.2.5.

$\boldsymbol{EF_{ij}}$ 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

Method 2 requires the derivation of more accurate, facility-specific emission factors to generate more accurate estimates of emissions of carbon dioxide from the production process. It utilises sampling and analysis of the lime outputs to estimate the composition of its contents and, from an understanding of the chemical reactions involved in the consumption of carbonate (calcination), the derivation of facility-specific emission factors.

(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:

$$EF_{ij} = F_i \times \frac{44.01}{56.08}$$

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

Method 3 is based on the Tier 3 approach in the IPCC Guidelines for National Greenhouse Inventories which utilises information on the purity of the carbonate inputs. This method requires sampling and analysis of the raw materials for qualities that affect emission levels such as the material's pure carbonate content.

(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:

$\boldsymbol{E_{ij}}$ 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.

$\boldsymbol{EF_{ij}}$ 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.

$\boldsymbol{Q_i}$ 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.

$\boldsymbol{F_{cal}}$ 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.

$\boldsymbol{A_{lkd}}$ 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.

$\boldsymbol{EF_{lkd}}$ is 0.440, which is the emission factor for calcined lime kiln dust lost from the kiln.

$\boldsymbol{F_{lkd}}$ 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 ~~4.15~~ 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 ~~4.16~~ to lime is taken to be a reference to carbonates.

Division 4.2.3 Use of carbonates for the production of a product other than cement clinker, lime or soda ash

This division is concerned with the consumption or any other use of carbonates that generates carbon dioxide emissions regardless of the industry in which they are used. Apart from the production of cement clinker and lime, addressed in Divisions 4.2.1 and 4.2.2, and soda ash, addressed in Division 4.2.4, activities that may be likely to use carbonates that generate emissions include the industries listed in Section 4.20.

4.20 Application

This Division applies to emissions from the use of carbonate for the production of a product other than cement clinker, lime or soda ash:

(a) involving the consumption or any other use of carbonates; and

(b) generating emissions of carbon dioxide.

Note Examples of activities involving the consumption of carbonates that generate emissions include the following:

- metallurgy
- glass manufacture, including fibreglass and mineral wools
- magnesia production
- agriculture
- construction
- environment pollution control
- use as a flux or slagging agent
- in-house production of lime in the metals industry.

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 or any other use of carbonates that produces carbon dioxide (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.

There is no method 2 for these sources because under this Division, unlike for Divisions 4.2.1 and 4.2.2, there is no equivalent to the estimation of emissions from the analysis of the products obtained from the consumption of carbonates.

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

Summary of available methods, for estimating emissions from other uses of carbonates, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.22	NO	NO
Method 2	NA	NO	NO
Method 3	Section 4.23	NO	NO
Method 4	Part 1.3	NO	NO

NA = Not available. NO = Not occurring

4.22 Method 1 — product other than cement clinker, lime or soda ash

Method 1 is derived from the methodology used for the *National Greenhouse Accounts*. It involves the multiplication of the quantity of raw carbonate material consumed in the calcining or other process by the emission factor for raw carbonate material and the fraction of the raw carbonate consumed during the production process.

Method 1 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each raw carbonate material consumed 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***) consumed 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 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 consumed 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 consumed 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 —90% calcium carbonate;
(b) for magnesium carbonate — 100% magnesium carbonate;
(c) for dolomite —95% dolomite.

4.23 Method 3 —product other than cement clinker, lime or soda ash

Method 3 is based on the Tier 3 approach in the *IPCC Guidelines for National Greenhouse Inventories* which utilises information on the purity of the carbonate inputs. This method requires sampling and analysis of the raw materials to determine the material's pure carbonate content, which is then used in the estimation. This estimation differs from Method 1, which utilises raw carbonate material with specified degrees of impurity as an input into the estimation.

(1) Method 3 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each pure carbonate consumed in the industrial process during the year as follows:

$$E_{ij} = EF_{ij} \times Q_i \times F_{cal}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide (***j***) from a pure carbonate (***i***) consumed in the industrial process during the year measured in CO_2-e tonnes.

$\boldsymbol{EF_{ij}}$ 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.

$\boldsymbol{Q_i}$ is the quantity of the pure carbonate (***i***) entering the industrial process during the year measured in tonnes and estimated under Division 4.2.5.

$\boldsymbol{F_{cal}}$ is:

(a) the fraction of the pure carbonate consumed 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 consumed 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

This Division addresses emissions from the consumption and also from the production of soda ash. The consumption of soda ash generates carbon dioxide emissions regardless of the industry that consumes the product. Examples of industries that use soda ash are given in Section 4.26.

4.26 Application

This Division applies to 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 As Method 1 relies on the assumption that the soda ash consumed is pure, there is no Method 2 or 3 for this category.

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

Summary of available methods, for estimating emissions from soda ash use, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.29	NO	NO
Methods 2, 3 and 4	NA	NO	NO

NA = not available. NO = Not occurring

4.29 Method 1 — use of soda ash

This Method is derived from the methodology used for the *National Greenhouse Accounts.* It involves the multiplication of the quantity of soda ash consumed in the production process by the emission factor for soda ash.

Method 1 is:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

$\boldsymbol{E_{ij}}$ 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.

$\boldsymbol{Q_i}$ 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.

$\boldsymbol{EF_{ij}}$ 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

Emissions from soda ash production arise from the consumption of fuels for energy and from the calcination of limestone and sodium bicarbonate. The methods provided in sections 4.30 to 4.33 are for the estimation of emissions from the consumption of fuels. Calculation of emissions from calcination of carbonates should be estimated using the methods in Division 4.2.3. The production of soda ash is a multi-step process involving the generation and reabsorption of carbon dioxide. To obtain a more accurate estimation of emissions from the consumption of fuels and calcination processes a carbon balance approach may be taken. Methods for a carbon balance approach to the estimation of emissions from sodium bicarbonate and sodium carbonate (soda ash) will be incorporated in the next update of the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* and will be based on the following section 4.33.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from soda ash production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.31	Section 4.31	Section 4.31
Method 2	Section 4.32	NA	NA
Method 3	Section 4.33	NA	NA
Method 4	Part 1.3	NA	NA

NA = Not available

4.31 Method 1 — production of soda ash

Method 1 is based on methodology used for the *National Greenhouse Accounts*. It involves the multiplication of the quantity of fuel consumed from the production of soda ash by the energy content and emission factor for the particular fuel type.

(1) Method 1 is:

$$E_{ij} = Q_i \times EC_i \times \left(\frac{EF_{ij}}{1000}\right)$$

where:

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.

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.

EC_i is the energy content factor for fuel type ***(i)*** used as a feedstock or carbon reductant in the production of soda ash during the year, estimated under section 6.5. 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.

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.

4.33A Method 1 — production of soda ash – using a carbon balance

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:

Σ_i means sum the carbon content values obtained for all fuel types (***i***) or carbonaceous input material.

1) CCF_i is the carbon content factor mentioned in Appendix A 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. For limestone input material the carbon content factor is equal to 0.108 tonnes of carbon per tonne of limestone entering the facility.

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:

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 type (***p***) produced during the year.

A_p is the quantity of product types (***p***) produced leaving the activity during the year measured in tonnes. These quantities are saleable end products.

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.

This component would account for non-oxidised or non-calcinated portions of fuel or carbonaceous inputs as well as on-site absorption of carbon dioxide from the process of brine purification using sodium carbonate and from alkali losses.

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.

4.33B Method 2 — production of soda ash – using a carbon balance

(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 1 of the *Determination*, 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 or equivalent.

4.33C Method 3 — production of soda ash – using a carbon balance

(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 1 of the *Determination*, 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 or equivalent.

Division 4.2.5 Measurement of quantity of carbonates consumed and products derived from carbonates

4.34 Purpose of Division and Background

This Division sets out how 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 purpose of working out the emissions released from the consumption and production of carbonates.

Division 4.2.5 specifies the criteria for the estimation of the amounts of carbonate consumed or produced during the operation of a facility during a year.

There are four criteria available for the estimation of the quantities of carbonates reflecting differing levels of measurement effort and precision.

Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen by the Reporter to estimate carbonate inputs and outputs is required to be reported. Measuring equipment calibrated to a measurement requirement mentioned in Sections 4.37 and 4.38 refers to the standards required for measurement to support all commercial transactions covered by the National Measurement Act 1960 and associated instruments.

In Section 4.37 it is intended that measured data for carbonates delivered (at the point of sale) would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the carbonate consumed at the facility are less than 5% of carbonate consumption for the facility during the year and that the stock changes by less than 1% during the year. It is intended that the analysis may be conducted by the supplier.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase their carbonates and where the Reporter also does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out in section 1.13 of transparency, comparability, accuracy and completeness. Such data would be classified and reported as 'BBB' data.

The restriction on the choice of criteria at 4.35 (3) is designed to ensure time series consistency of the measurements.

4.35 Criteria for measurement— criterion A and restrictions on the use of all criteria

(1) 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 in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the carbonates, or the dispatch of the products derived from carbonates, involves a commercial transaction, the quantity of the carbonates or products must be estimated using one of the following criteria:

(a) the quantity of the carbonates acquired or products dispatched for the facility during the year as evidenced by invoices issued by the vendor of the carbonates or products (***criterion A***);

(b) as provided in section 4.36 (***criterion AA***);

(c) as provided in section 4.37 (***criterion AAA***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 4.37 (2) (a), is used to estimate the quantity of carbonates acquired or products dispatched, then, in each year following that year, only criterion AA, or criterion AAA using paragraph 4.37 (2) (a), (respectively) is to be used.

Acquisition does not involve commercial transaction

(4) If the acquisition of the carbonates or the dispatch of the products does not involve a commercial transaction, the quantity the carbonates or products must be estimated using one of the following criteria:
(a) as provided in paragraph 4.37 (2) (a) (***criterion AAA***);
(b) 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 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.

4.39A Reporting

The corporation's report must include information for the facility in relation to the greenhouse gas emissions from the source during the reporting year and must identify:

a) the criteria used by the corporation to estimate the amount of carbonate inputs and/or outputs for the source;

(b) the methods used by the corporation to estimate the greenhouse gas emissions from the source; and

(c) the amount of each greenhouse gas that is emitted.

Additional emissions-related information set out in Regulation 4.13, should also be reported.

Reporters should refer to Part 2.7A for the reporting of the consumption of fossil fuels used as a feedstock or reductant used in the production of soda ash, facility-specific emission factors and the emissions associated with the consumption of those fossil fuels.

For the reporting of all sources of emissions not covered by this Part, Reporters should refer to other chapters and parts of these Guidelines and the Regulations for reporting details.

Part 4.3 Industrial processes — chemical industry

This Part applies to any chemical industry that generates emissions of carbon dioxide through the use of fuels as feedstocks or as carbon reductants, as described below. Nitric acid production is also addressed in this chapter.

It is intended that the quantities of fuels consumed for industrial process purposes are to be estimated in accordance with the same criteria as has been set out for fuels consumption in chapter 2.

Other sources of emissions arising from the production of the products listed below, such as from the combustion of fuels for energy purposes, are not described in this chapter and must be estimated using the Methods described in other chapters.

Division 4.3.1 Ammonia production

Ammonia production involves the consumption of fossil fuel for both energy and non-energy purposes. CO_2 emissions are generated in the primary steam reforming process in which the source of fuel, commonly natural gas, is used to derive hydrogen.

Emissions from the use of natural gas for its energy value should be separated from its non-energy purposes, if possible. Emissions and fuels consumed for energy should be estimated using Methods provided under chapter 2. Emissions and fuel use as an input into ammonia production should be estimated using Methods provided in this Division. If this separation cannot be completed then, in order to minimise the risk of duplication or omission, all emissions from the use of gas in ammonia production should be included within the industrial processes sector using methods detailed in this Division.

4.40 Application

This Division applies to 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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from ammonia production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.42	NO	NO
Method 2	Section 4.43	NO	NO
Method 3	Section 4.44	NO	NO
Method 4	Method 4 under Part 1.3.	NO	NO

NO = Not occurring.

4.42 Method 1 — ammonia production

Method 1 for emissions of carbon dioxide released from the use of fuels as feedstocks in the production of ammonia is derived from the methodology used for the *National Greenhouse Accounts*.

(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 for fuel type *(i)* used as a feedstock in the production of ammonia during the year, estimated under section 6.5.

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 as given in the table in Division 2.2.2.

R is the quantity of carbon dioxide measured in CO_2-e tonnes 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.

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 $\boldsymbol{EF_{ij}}$.

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 $\boldsymbol{EF_{ij}}$.

Division 4.3.2 Nitric acid production

The manufacture of nitric acid (HNO_3) generates nitrous oxide (N_2O) as a by-product of the high temperature catalytic oxidation of ammonia (NH_3).

4.45 Application

This Division applies to chemical industry nitric acid production.

4.46 Available methods

Method 1, 2 or 4 are available for plants, unless abatement measures are in place – in which case Method 2 or 4 must be used.

(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 emissions 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.

Summary of available methods, for estimating emissions from nitric acid production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	NO	NO	Section 4.47
Method 2	NO	NO	Section 4.48
Method 3	NO	NO	NA
Method 4	NO	NO	Method 4 under Part 1.3

NO = Not occurring , NA = Not available.

4.47 Method 1 — nitric acid production

Method 1 for emissions released from the production of nitric acid (is derived from the methodology used for the *National Greenhouse Accounts*, with the emission factors for individual plants taken from the *IPCC Guidelines for National Greenhouse Inventories Volume 3, Part 1*.

(1) Method 1 is:

$$E_{ijk} = EF_{ijk} \times A_{ik}$$

where:

$\boldsymbol{E_{ijk}}$ 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.

$\boldsymbol{EF_{ijk}}$ is the emission factor of nitrous oxide for each tonne of nitric acid produced during the year from plant type (***k***).

$\boldsymbol{A_{ik}}$ is the quantity, measured in tonnes, of nitric acid produced during the year from plant type (***k***).

(2) For $\boldsymbol{EF_{ijk}}$ 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.

Example

A high pressure nitric acid plant produces 45,000 tonnes of nitric acid during the year. The Reporter elects to use Method 1 *(Division 4.3.2)* for each of greenhouse emission gases (*j*) (nitrous oxide) to calculate the Industrial Process emissions. Emissions are estimated as follows:

$$E_{ijk} = EF_{ijk} \times A_{ik}$$

where:

$\boldsymbol{E_{ijk}}$ is the emissions of nitrous oxide released during the year from the production of nitric acid at the plant type (k) measured in CO_2 e tonnes.

$\boldsymbol{EF_{ijk}}$ is the emission factor of nitrous oxide for each tonne of nitric acid produced during the year from plant type (k). **In this case the emission factor is 2.79 tonnes CO_2-e per tonne of nitric acid production for a high pressure plant.**

$\boldsymbol{A_{ik}}$ is the quantity, measured in tonnes, of nitric acid produced during the year from plant type (k). **In this case production is 45,000 tonnes.**

Therefore, to estimate emissions of nitrous oxide in CO_2-e tonnes :

=45,000 x 2.79

Total emissions of nitrous oxide = 125,550 t CO_2-e

4.48 Method 2 — nitric acid production

For Method 2, facility-specific emission factors may be derived from periodic emissions monitoring undertaken in accordance with the provisions of Chapter 1 (and, in particular, section 1.28). These facility-specific emission factors should be substituted into the equation specified in 4.47 (1) to estimate emissions.

(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 $\boldsymbol{EF_{ijk}}$:
   (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

Method 1 for emissions released from the production of adipic acid is described in *IPCC 2006 Guidelines for National Greenhouse Gas Inventories Volume 3, Part 1*. Currently, there is no adipic acid production recorded in Australia.

4.49 Application

This Division applies to 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 emissions another method may be used that is consistent with the principles in section 1.13.

Division 4.3.4 Carbide production

Method 1 for emissions released from the production of carbide is described in *IPCC 2006 Guidelines for National Greenhouse Gas Inventories Volume 3, Part 1*. Currently, there is no carbide production recorded in Australia.

4.51 Application

This Division applies to 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 emissions another method may be used that is consistent with the principles in section 1.13.

Division 4.3.5 Chemical or mineral production, other than carbide production, using a carbon reductant

Emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of chemical or mineral products (other than carbide) should be

estimated using methods provided in this Division. The use of fuels for energy purposes should be estimated using methods in Chapter 2 and reported separately.

Some of the industries included in this Division are listed below.

4.53 Application

This Division applies to emissions from activities producing a chemical or mineral product (other than carbide production) using a carbon reductant, including the following products:

(a) titanium dioxide;

(b) synthetic rutile;

(c) glass.

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 a chemical or mineral product:

(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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from titanium dioxide production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.55	NO	NO
Method 2	Section 4.56	NO	NO
Method 3	Section 4.57	NO	NO
Method 4	Part 1.3	NO	NO

NO = Not occurring.

4.55 Method 1 — chemical or mineral production, other than carbide production, using a carbon reductant

Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of a chemical or mineral product is derived from the methodology used for the *National Greenhouse Accounts*.

(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 activities producing a chemical or mineral product, other than carbide production, using a carbon reductant, 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 a chemical or mineral product 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 for the fuel type ***(i)*** consumed as a carbon reductant in the production of a chemical or mineral product during the year, estimated under section 6.5.

EF_{ij} is the carbon dioxide emission factor for the fuel type (***i***) used in the production of a chemical or mineral product during the year, including effects of oxidation, measured in kilograms for each gigajoule according to source as mentioned in:

(a) for solid fuel combustion — Division 2.2.2; and

(b) for gaseous fuel combustion — Division 2.3.2; and

(c) for liquid fuel combustion for stationary energy purposes — Division 2.4.2.

4.56 Method 2 — chemical or mineral production, other than carbide production, using a carbon reductant

Method 2 is:

(a) for estimating emissions released in the consumption of a carbon reductant in the production of a chemical or mineral product using solid fuels during the year — 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 a chemical or mineral product using gaseous fuels during the year — 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 a chemical or mineral product using liquid fuels during the year — the same as method 2 under Division 2.4.3.

4.57 Method 3 — chemical or mineral production, other than carbide production, using a carbon reductant

Method 3 is:

(a) for estimating emissions released in the consumption of a carbon reductant in the production of a chemical or mineral product using solid fuels during the year — 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 a chemical or mineral product using gaseous fuels during the year — 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 a chemical or mineral product using liquid fuels during the year — the same as method 3 under Division 2.4.4.

Example

A synthetic rutile production plant consumes 15,000 tonnes of black coal used as a reductant during the year. The Reporter elects to use Method 1 *(Division 4.3.6)* to calculate carbon dioxide emissions. Emissions are estimated as follows:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000}$$

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. **In this case 15,000 tonnes of black coal was used as a reductant.**

EC_i is the energy content factor of the fuel type (***i***), used in the production of synthetic rutile during the year, measured as energy content in gigajoules per the appropriate unit. **In this case, energy content for black coal is 27GJ/t, sourced from Part 1 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. **In this case, the CO_2 emission factor for black coal is 88.2 kg CO2-e/GJ, sourced from Part 1 of Schedule 1.**

Therefore, to calculate emissions of carbon dioxide in CO_2-e tonnes:

For carbon dioxide

= (15000 x 27 x 88.2)/1000

Total emissions of carbon dioxide = 35,721 t CO_2-e

4.57A Reporting

The corporation's report must include information for the facility in relation to greenhouse gas emissions from the source during the year and must identify:

(a) the criteria used by the corporation to estimate the amount of fuel consumed for the source.

(b) the methods used by the corporation to estimate the industrial process emissions from the source.

(c) the amount of each greenhouse gas that is emitted.

Additional emissions-related information set out in Regulation 4.14, should also be reported.

Reporters should refer to Part 2.7A for the reporting of the consumption of fossil fuels used as a feedstock or reductant for the purpose of making a chemical product, facility specific emission factors and the emissions associated with the consumption of those fossil fuels.

For the reporting of all sources of emissions not covered by this Part, Reporters should refer to other chapters and parts of these Guidelines and the Regulations for reporting details.

Part 4.4 Industrial processes — metal industry

This Part applies to any metal industry that generates emissions of carbon dioxide through the use of fuels as carbon reductants, as described below. Perfluorocarbon emissions from aluminium production are also addressed in this part.

The quantities of fuels consumed for industrial process purposes should be estimated in accordance with the same criteria as has been set out for fuels consumption in chapter 2.

Other sources of emissions arising from the production of the products listed below, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Division 4.4.1 Iron, steel or other metal production using an integrated metalworks

This division applies to any facility that produces both coke and a metal in an integrated metalworks. Metals such as iron, steel, lead and silicon may be produced in an integrated metalworks. The methods for estimating emissions of carbon dioxide are based on a carbon balance approach in order to reduce the complexity of the calculation for these facilities.

4.63 Application

This Division applies to emissions from integrated metalworks.

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 a metal, for example, an integrated metalworks.

(2) An ***integrated metalworks*** means a metal works that produces coke and a metal, for example, iron and steel.

(3) The emissions from the activity are to be worked out as a total of emissions released from the production of a metal and from all other emissions released from the operation of the activity (including the production of coke if the activity is an integrated metalworks).

(4) However, the amount of emissions to be determined for this source is only the amount of emissions from the use of coke as a carbon reductant in the metal production estimated in accordance with section 2.69.

Note The amount of emissions to be determined for other activities is as provided for in other provisions of this Determination.

4.65 Available methods for production of a metal from an integrated metalworks

(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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from iron and steel production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.66	NO	NO
Method 2	Section 4.67	NO	NO
Method 3	Section 4.68	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NA = Not available. NO = Not occurring.

4.66 Method 1 — production of a metal from an integrated metalworks

Method 1 sets out the estimation of emissions from a facility producing both a metal and coke. It specifies that emissions should be estimated using a carbon mass balance approach for the facility as a whole. Method 1 utilises carbon content factors listed in Appendix A (Schedule 3 in the Determination). These carbon content factors are derived directly from the carbon dioxide emission factors listed in Chapter 2. There are no carbon content factors specified for products or for waste by-products. It is intended that these should be estimated by industry based on the principles of Section 1.13, namely transparency, comparability, accuracy and completeness.

The carbon mass balance approach requires fuels to be estimated in accordance with Criterion A – based on quantities of fuels delivered rather than consumed. This is because criteria AA or AAA cannot be utilised as changes in stocks of fuels are explicitly taken into account in the mass balance estimation directly.

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:

Σ_i means sum the carbon content values obtained for all fuel types (***i***) or carbonaceous input material.

CCF_i is the carbon content factor mentioned in Appendix A 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.

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:

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 type (***p***) produced during the year.

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 — production of a metal from an integrated metalworks

(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 1, 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 — production of a metal from an integrated metalworks

(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 1, 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 Ferroalloys production

Emissions of CO_2 occur during ferroalloy production as a result of the use of carbon reductants such as coke.

4.69 Application

This Division applies to 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 emissions another method may be used that is consistent with the principles in section 1.13.

Methane and nitrous oxide emissions arising from the combustion of reductants should be estimated using methods described in Chapter 2 – Fuel Combustion.

Summary of available methods, for estimating emissions from ferralloy metal production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.71	NO	NO
Method 2	Section 4.72	NO	NO
Method 3	Section 4.73	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NO = Not occurring.

4.71 Method 1 — ferroalloy metal

Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of ferroalloy metals is derived from the methodology used for the *National Greenhouse Accounts*.

(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 for the fuel type ***(i)*** consumed as a carbon reductant in the production of ferroalloy metal during the year, estimated under section 6.5.

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), for the factor EF_{ij} — the emission factor of each carbon reductant means the emission factor for that reductant as mentioned in Schedule 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 production (carbon dioxide emissions)

4.74 Application

This Division applies to aluminium production.

Subdivision 4.4.3.1 Aluminium — emissions from consumption of baked carbon anodes in aluminium production

Method 1 for carbon dioxide emissions from aluminium production is intended to reproduce the method set out in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, which is drawn from the *International Aluminium Institute Greenhouse Gas Protocol*. As for fuels combusted for energy, Methods 2 and 3 for the category provide for sampling and analysis of fuels in accordance with Chapter 2 to determine facility-specific carbon content factors to be applied in estimating emissions.

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 emissions another method may be used that is consistent with the principles in section 1.13.

Available methods, for estimating emissions from aluminium involving the consumption of baked carbon anodes, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.76	NO	NO
Method 2	Section 4.77	NO	NO
Method 3	Section 4.78	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NA = Not available. NO = Not occurring.

4.76 Method 1 — aluminium (baked carbon anode consumption)

Method 1 is:

$$E_{ij}=A_i \times EF_{ij}$$

where:

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.

A_i is the amount of primary aluminium produced in tonnes during the year.

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.

S_a is the mass of sulphur content in baked carbon anodes that are consumed in the production of aluminium during the year, expressed as a percentage of the mass of the baked carbon anodes, and is taken to be 2.

Ash_a is the mass of ash content in baked carbon anodes that are consumed in the production of aluminium during the year, expressed as a percentage of the mass of the baked carbon anodes, and is taken to be 0.4.

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*, S_a and 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.

(3) However, in applying method 1 under section 4.76, the factor S_a may be the amount for the factor as mentioned in section 4.76.

(4) If the amount for the factor S_a as mentioned in section 4.76 is not used, then S_a must be determined by sampling and analysing the fuel type ***(i)*** for sulphur content in accordance with subsection (2).

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*, S_a and 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 emissions another method may be used that is consistent with the principles in section 1.13.

Available methods, for estimating emissions from aluminium involving the production of baked carbon anodes, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.80	NO	NO
Method 2	Section 4.81	NO	NO
Method 3	Section 4.82	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NO = Not occurring.

4.80 Method 1 — aluminium (baked carbon anode production)

Method 1 is:

$$E_{ij} = \left(GA - Hw - BA - WT\right) \times 3.664 + \left(\frac{\sum Q_i}{BA} \times BA \times \frac{\left(100 - S_i - Ash_i\right)}{100}\right) \times 3.664$$

where:

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 mass of sulphur content in baked carbon anodes that are consumed in the production of aluminium during the year, expressed as a percentage of the mass of the baked carbon anodes, and is taken to be 2.

Ash_i is the mass of ash content in baked carbon anodes that are consumed in the production of aluminium during the year, expressed as a percentage of the mass of the baked carbon anodes, and is taken to be 0.4.

Note The default value for H_w is 0.5% of ***GA***.

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 production (perfluoronated carbon compound emissions)

Method 2 and Method 3 are to be drawn from the US Environment Protection Agency, *Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminium Production* as referenced in the *International Aluminium Institute Greenhouse Gas Protocol*.

4.83 Application

This Division applies to 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:

(b) method 2 under section 4.86;

(c) method 3 under section 4.87.

Note There is no method 1 or 4 for this provision.

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

Summary of available methods, for estimating tetrafluoromethane emissions aluminium production, by emissions of gas type (j)

	Tetrafluoromethane
Method 2	Section 4.86
Method 3	Section 4.87

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:

(b) method 2 under section 4.90;(c) method 3 under section 4.91.

Note There is no method 1 or 4 for this provision.

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

Summary of available methods, for estimating hexafluoroethane emissions aluminium production, by emissions of gas type (j)

	Hexafluoroethane
Method 2	Section 4.90
Method 3	Section 4.91

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

This Division applies to the production of metal, other than iron and steel, ferro-alloy metal, aluminium or any other metal produced in an integrated metalworks, that involves the use of fuels as carbon reductants.

4.92 Application

This Division applies to emissions from activities producing metals other than aluminium, ferroalloys, iron and steel or any other metal produced using an integrated metal works.

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 metalsto which this Division applies:

(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 emissions another method may be used that is consistent with the principles in section 1.13.

Summary of available methods, for estimating emissions from other metal production, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Method 1	Section 4.94	NO	NO
Method 2	Section 4.95	NO	NO
Method 3	Section 4.96	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NO = Not occurring.

4.94 Method 1 — other metals

Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of other metals is derived from the methodology used for the *National Greenhouse Accounts*.

(1) Method 1 is:

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

where:

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.

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.

EC_i is the energy content factor for the fuel type ***(i)*** consumed as a carbon reductant in the production of the metal during the year, estimated under section 6.5.

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), for EF_i, the emission factor of each carbon reductant means the emission factor for that reductant as mentioned in Schedule 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.

4.96A Reporting

The *National Greenhouse and Energy Reporting Regulations 2008,* Division 4.4 specifies information relating to greenhouse gas emissions that must be included in a registered corporation's report for a reporting year if the corporation's group meets a threshold in subsection 13 (1) of the Act for that year.

The corporation's report must include information for the facility in relation to greenhouse gas emissions from the source during the year and must identify:

(a) the criteria used by the corporation to estimate the amount of fuel consumed for the source;

(b) the methods used by the corporation to estimate the greenhouse gas emissions from the source;

(c) the additional emissions-related information listed in Regulation 4.15; and

(d) the amount of each greenhouse gas that is emitted.

Reporters should refer to Part 2.7A for the reporting of the consumption of fossil fuels used as a feedstock or reductant for the purpose of making a metal product, facility specific emission factors and the emissions associated with the consumption of those fossil fuels.

For the reporting of all sources of emissions not covered by this Part, Reporters should refer to other chapters and parts of these Guidelines and the Regulations for reporting details.

Part 4.5 Industrial processes — emissions of hydrofluorocarbons and sulphur hexafluoride gases

Emissions of hydrofluorocarbon (HFC) or sulphur hexafluoride (SF_6) gases arise as fugitive emissions from the use of equipment, such as refrigeration, that contains these gases. Production of hydrofluorocarbons and sulphur hexafluoride currently does not occur in Australia.

4.97 Application

This Part applies to emissions of hydrofluorocarbons and sulphur hexafluoride gases.

4.98 Available method

(1) Subject to section 1.18, 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, one of the following methods must be used:

(a) method 1 under section 4.102;

(b) method 2, for both hydrofluorocarbons and sulphur hexafluoride, under section 4.103;

(c) method 3:

(i) for hydrofluorocarbons under subsection 4.104 (1);

(ii) for sulphur hexafluoride under subsection 4.104 (2).

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

Note There is no method 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*

Only a subset of Reporters need to report estimates of emissions of hydrofluorocarbon gases. This reflects the assessment that the benefits of reporting may not exceed the costs of measurement in many instances given the large number of appliances that contain relatively small refrigerant charges, and the small share of

total emissions that these emission sources would represent for many companies and facilities.

Emissions of hydrofluorocarbon gases need only be estimated if:

(a) hydrofluorocarbon gases are used in the equipment types specified in 4.102(4);
(b) the equipment type contains a refrigerant charge of more than 100 kilograms of refrigerants for each unit;
(c) the refrigerants have a weighted-average Global Warming Potential of over 1000; and
(d) the equipment is operated by a facility attributable to an ANZSIC classification listed in 4.100 (1) (b).

All users of SF_6 should report SF_6 emissions.

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

These thresholds are intended to limit the application of the Part because of the large number of diverse and minor sources of emissions for this category.

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

Method 1 for emissions of HFCs and SF_6 calculates emissions during the year using default leakage rates for the particular types of equipment within the facility. HFC and SF_6 emissions should be estimated separately according to Method 1.

(1) Method 1 is:

$$E_{jk} = Stock_{jk} \times L_{jk}$$

where:

$\boldsymbol{E_{jk}}$ 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.

$\boldsymbol{Stock_{jk}}$ 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.

$\boldsymbol{L_{jk}}$ 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 $\boldsymbol{Stock_{jk}}$, 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

Both the type and quantity of hydrofluorocarbon or SF_6 contained in the equipment should be shown on the equipment compliance plate. Quantities of hydrofluorocarbon or SF_6 should be converted into CO_2-e using the Global Warming Potentials listed in Appendix C.

Example

For a commercial refrigeration unit with a stock of 2 tonnes of HFC-23 the emissions in CO_2-e tonnes are:

$$E_{jk} = Stock_{jk} \times L_{jk}$$

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.

Convert the tonnes of HFC-23 to CO_2-e tonnes using the global warming potential for HFC-23 listed in Appendix C

Stock = 2 x GWP

= 2 x 11,700

= 23,400 CO_2-e tonnes

Emissions in CO_2-e tonnes are:

= 23,400 x 0.23

= 5382 t CO_2-e

4.103 Method 2

The stock may also be estimated from mass balance calculations based on the opening stock of gas; transfers into the facility from additions of gas from purchases of new equipment and replenishments; and transfers out of the facility from disposal of equipment or gas. Method 2 uses the mass balance worksheet in Appendix A of the ENA Industry Guideline for SF_6 Management and reporters should use this worksheet for both SF_6 and hydrofluorocarbon gases. A separate worksheet should be completed for each type of gas. Note that the total annual loss estimate (item F in the mass balance worksheet) for each type of gas should be converted into CO_2-e using the Global Warming Potentials listed in Appendix C. Where a refrigerant blend is used a worksheet for that particular refrigerant blend should be completed and a weighted average of the global warming potentials for each type of HFC in the blend should be used to convert to CO_2-e.

As the mass balance worksheet may not include all items for addition and subtraction applicable to the management of refrigerant systems (hydrofluorocarbons), Reporters of HFCs may modify the worksheet in order to obtain a more accurate estimate of emissions.

Storage means all equipment, cylinders and other containers which hold hydrofluorocarbons or SF_6 not in use and which meet the requirements of 4.100 and 4.101.

> For paragraph 4.98 (1) (b), method 2 for estimating emissions of hydrofluorocarbons or sulphur hexafluoride during a year uses the table in Appendix A of the publication entitled *ENA Industry Guideline for SF_6 Management*, Energy Networks Association, 2008.

4.104 Method 3

Alternatively, emissions may be estimated from data on replenishments of gases in equipment as a proxy for leakage and using an assumption that the stock levels of gases within the equipment are maintained at constant levels in order to maintain

constant operating efficiency levels. Method 3 uses this approach and refers reporters of SF_6 to the whole section in the *ENA Industry Guideline for SF_6 Management,* section 6.3, which provides a discussion as well as a worksheet (by reference to Appendix B).

For reporters of HFCs, however, Method 3 simply references the worksheet in Appendix B of the *ENA Industry Guideline for SF_6 Management,* and although it refers to SF_6 can also be applied to HFCs.

A separate worksheet should be completed for each type of gas. The worksheet in Appendix B may not include all the point sources of losses for both SF_6 and HFCs. Therefore this worksheet may be modified to include more point sources where they have been identified by the Reporter.

Note that the total annual loss of each type of gas should be converted into CO_2-e using the Global Warming Potentials listed in Appendix C. Where a refrigerant blend is used a worksheet for that particular refrigerant blend should be completed and a weighted average of the global warming potentials for each type of HFC in the blend should be used to convert to CO_2-e.

Storage means all equipment, cylinders and other containers which hold hydrofluorocarbons or SF_6 not in use and which meet the requirements of 4.100 and 4.101.

(1) For paragraph 4.98 (1) (c), method 3 for estimating emissions of hydrofluorocarbons uses the table in Appendix B of the publication entitled *ENA Industry Guideline for SF_6 Management*, Energy Networks Association, 2008.

(2) For paragraph 4.98 (1) (c), method 3 for estimating emissions of sulphur hexafluoride during a year uses the Tier 3 method set out in section 6.3 of the publication mentioned in subsection (1).

4.104A Reporting

The National Greenhouse and Energy Reporting Regulations 2008, Division 4.4 specifies information relating to greenhouse gas emissions that must be included in a registered corporation's report for a reporting year if the corporation's group meets a threshold in subsection 13 (1) of the Act for that year.

The corporation's report must include information for the facility in relation to greenhouse gas emissions from the source during the year and must identify:

(a) the amount of each greenhouse gas that is emitted.

Chapter 5 Waste

Part 5.1 Preliminary

5.1 Outline of Chapter

This Chapter provides for emissions from the following sources:

(a) solid waste disposal on land (see Part 5.2);
(b) wastewater handling (domestic and commercial) (see Part 5.3);
(c) wastewater handling (industrial) (see Part 5.4);
(d) waste incineration (see Part 5.5).

Throughout the Waste chapter, emissions of CO_2 generated from waste management are considered to be from biomass sources and therefore do not need to be estimated. For example, landfill gas comprises both methane and carbon dioxide but only the methane component should be reported.

Carbon dioxide produced from the flaring of methane from landfill gas or other emission sources in this chapter is also considered as having been derived from biomass sources and should not be reported.

Emissions of all gases arising from other, non-waste processes from the facility – such as emissions from the combustion of fuels for energy – must be estimated using methods described in the appropriate chapter of these Guidelines.

Part 5.2 Solid waste disposal on land

Division 5.2.1 Preliminary

5.2 Application

(1) This Part applies to emissions released from:

(a) the decomposition of organic material from solid waste disposal in a landfill; and

(b) flaring of landfill gas.

(2) This Part does not apply to a landfill unless:

(a) the landfill was open for the acceptance of waste on and after 1 July 2008; and

(b) during a year the landfill emits more than 10,000 tonnes of CO_2 –e from solid waste disposal on land at the landfill.

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.

(2) Under paragraph (1) (b), the same method must be used for estimating emissions of each gas type.

(3) For incidental emissions 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.

Summary of available methods, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Solid waste disposal at landfill			
Method 1	NA	Section 5.4	NO
Method 2	NA	Section 5.15	NO
Method 3	NA	Section 5.18	NO
Method 4	NA	NA	NO
Methane flared from the operation of the landfill			
Method 1	NA	Section 5.19	Section 5.19
Method 2	NA	Section 5.20	Section 5.20
Method 3	NA	Section 5.21	Section 5.21
Method 4	NA	NA	NA
Biological treatment of solid waste			
Method 1	NA	Section 5.22	Section 5.22

NA = Not available or Not applicable. NO = Not occurring.

Future work

It is intended that methods for the direct monitoring of emissions at landfills be developed over time. No method 4 has been specified in the Determination. Further development work and consultation is required to establish the appropriateness of various monitoring techniques before their inclusion.

The Department of Climate Change is also monitoring the results of research being conducted into the fractions of degradable organic carbon dissimilated for various Australian waste types and certain other parameters including methane correction factors, methane gas capture efficiencies, and oxidation factors. The Department plans to review the results of this research, once it is completed, and to give consideration to an update of factors contained in these Guidelines. A critical criterion for any update of such factors is that they must be acceptable to international review processes.

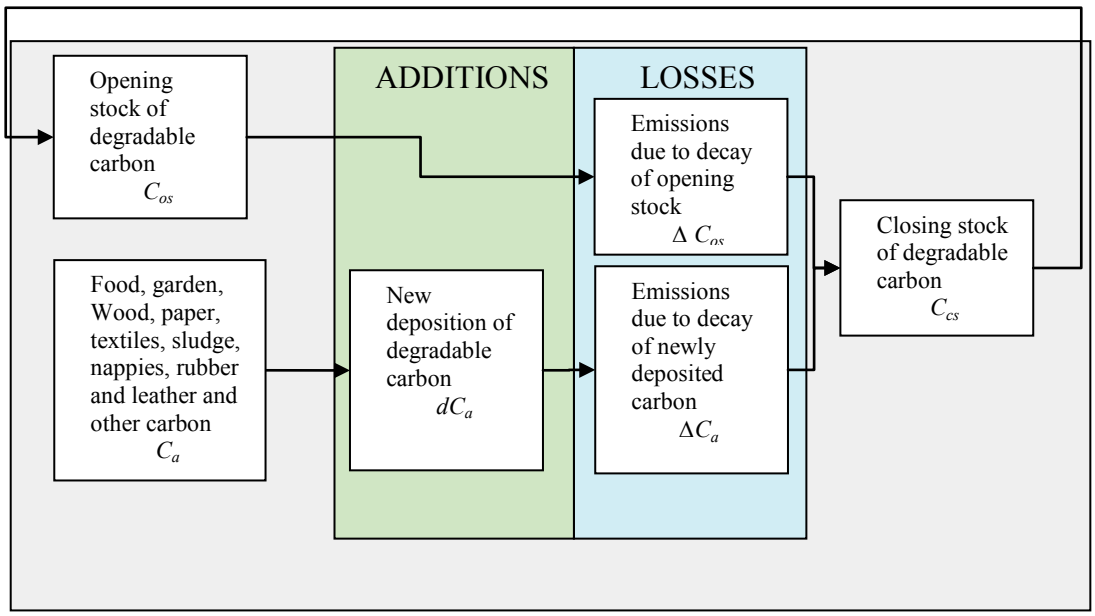
Division 5.2.2 Method 1 — emissions of methane released from landfills

Method 1 is consistent with the methods used for Australia's *National Greenhouse Accounts.* It is intended that methane generated from solid waste disposal is estimated principally using data on the receipt of solid waste materials at the landfill (often required under State Government levy or reporting arrangements) and the First Order Decay (FOD) model provided in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, except in certain circumstances specified below.

The quantity of methane generated from solid waste disposal is estimated using a carbon mass balance approach consistent with the First Order Decay (FOD) model (IPCC 2006). Methane is generated by the decay of the decomposable degradable organic carbon stock in the landfill site and reflects waste disposal activity over many decades. The concept of the carbon stock model approach is illustrated in Figure 1.

Methane generated from the landfill at any point in time depends on the stock of decomposable degradable organic carbon inside the landfill. The opening stock of decomposable degradable organic carbon decays over the year (ΔC_{os}) resulting in the generation of landfill gas with the remainder going to the year's closing stock. Additionally, decomposable degradable organic carbon enters the landfill system through the deposition of new waste during the reporting year dC_a. A portion of the newly deposited decomposable degradable organic carbon decays in the reporting year ΔC_a and the remainder contributes to the closing stock of decomposable degradable organic carbon C_{cs}.

Figure 1: Carbon stock model flow chart



Principal method for estimation of emissions

The total change in decomposable degradable organic carbon stock is estimated simultaneously with estimated methane generation.

Methane generated at the landfill:

$$CH_{4\ gen} = (\Delta C_a(t) + \Delta C_{os}(t)) \times F \times 1.336 \text{ x } 21$$

Decomposable degradable organic carbon lost through decay during the year t:

$$\Delta C_{os}(t) = C_{os}(t) \text{ x } (1-e^{-k})$$

$$\Delta C_a(t) = dC_a(t) \text{ x } [1-e^{-k \text{ x } (13-M)/12}]$$

Accumulated decomposable degradable organic carbon at the landfill at the end of the year

$$C_{cs}(t) = C_{os}(t) - \Delta C_{os}(t) + dC_a(t) - \Delta C_a(t)$$

Where:

$CH_{4\ gen}$ is the quantity of methane generated at the landfill (in tonnes of CO_2-e)

dCa(t) is the quantity of decomposable degradable organic carbon from newly deposited waste arriving at the landfill and is derived using the equation:

$$dC_a(t) = \sum_i (Ca(t) \text{ x } DOC_{Fi} \text{ x } MCF)$$

Where:

$C_a(t)$ is the quantity of degradable organic carbon in newly deposited waste at the landfill during the year t (in tonnes)

DOC_F is the fraction of degradable organic carbon dissimilated and is equal to 0.5 for all waste types *i*.

MCF is the methane correction factor for aerobic decomposition and is equal to 1.

Sum for all waste types *i*.

$\Delta C_a(t)$ is the quantity of decomposable degradable organic carbon from newly deposited waste arriving at the landfill lost through decay (decomposition) (in tonnes)

$\Delta C_{os}(t)$ is the quantity of decomposable degradable organic carbon from the opening stock of carbon at the landfill lost through decay (decomposition) (in tonnes)

F is the fraction of CH_4, by volume, generated in landfill gas (and equal to 0.5)

1.336 is the conversion factor from a mass of C to a mass of CH_4

$C_{os}(t)$ is the quantity of decomposable degradable organic carbon accumulated in the landfill at the beginning of the year t (in tonnes)

$C_{cs}(t)$ is the quantity of decomposable degradable organic carbon accumulated in the landfill at the end of the year t (in tonnes)

$C_a(t)$ is the quantity of decomposable degradable organic carbon in newly deposited waste at the landfill during the year t (in tonnes)

The opening stock of degradable organic carbon for a year $C_{os}(t)$ is equal to the closing stock $C_{cs}(t-1)$ of the previous year

M = month when decay process commences, equal to the average delay time (months) + 7. Landfill operators may choose an appropriate value for average delay time between 0 and 12. In the absence of information on delay time, a value of 0 months (immediate decay) may be used for average delay time (M = 7).

k = methane generation constant

t = year *t* (reporting year)

The FOD model estimates CH_4 generated in any given year by adding the newly deposited waste (dC_a) into the disposal site in one year to the waste left over from the previous year (which is taken as the current year's opening stock – C_{os}). The CH_4 generation for the year is then calculated from this 'running total' of the decomposable degradable organic carbon remaining in the site.

The basis for this approach lies in the first order reaction. With a first order reaction the amount of product (here degradable organic carbon decomposed - $\Delta C_a(t) + \Delta C_{os}(t)$) - is always proportional to the amount of reactant (here $C_{os} + dC_a$).

Alternative method for estimation of emissions

Section 5.4 also sets out the circumstances in which an alternative approach to the estimation of emissions will apply. The alternative approach will apply to a facility that captures methane generated by the landfill and where the estimates of the quantity of methane captured for combustion (either at the landfill or elsewhere) and from flaring exceed 75 per cent of the estimated emissions generated by the landfill according to the application of the Tier 2 FOD model.

If the 75 per cent threshold is exceeded, (that is, if the quantity of methane captured, transferred offsite or flared exceeds 75 per cent of the estimated methane generated at the landfill) then it is intended that emissions would be estimated as [1/0.75] multiplied by the quantity of methane captured.

This mixed approach ensures that where a more accurate estimate of emissions generated by the landfill is available – i.e. based on the quantity of emissions captured – that this better data is substituted for the Tier 2 FOD model-generated emissions data.

The choice of 75 per cent as the threshold value reflects advice in the Department of Environment and Heritage publication, National Pollution Inventory – *Emission Estimation Manual for Municipal Solid Waste (MSW) Landfills, Version 1.2,* May 2005, that this constitutes the most common assumption about capture efficiency of landfill sites. A similar approach has recently been adopted by the US Environment Protection Agency.

It is intended that Reporters will be able to use higher-order methods – in particular, method 2 – to establish higher capture efficiencies. That is, the 75 per cent cap does not apply in the application of method 2 because method 2 provides an appropriate basis for the estimation of emissions that escape the capture systems in place.

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 the emissions of methane released by the landfill during the year measured in CO_2-e tonnes.

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:

$$\frac{\gamma\,(Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

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 CO_2-e tonnes.

(3) For subsection (1), if:

$$\frac{\gamma\,(Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is greater than 0.75 then:

$$CH_4^* = \gamma\left(Q_{cap} + Q_{flared} + Q_{tr}\right) \times \left(\frac{1}{0.75}\right)$$

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.

(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 disposed of in the landfill during the year (see section 5.5);

(ii) the composition of the solid waste disposed of in the landfill during the year (see section 5.9);

(iii) the degradable organic carbon content of the solid waste disposed of in 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).

Measurement of quantities of degradable organic carbon deposited at landfill

The quantities of degradable organic carbon deposited at the landfill by waste type are calculated according to the following equation:

$$C_{a(i)}(t) = \sum_j Q_{waste} \text{ x } F_{Stream(j)} \text{ x } F_{(i)} \text{ x } DOC_{(i)}$$

Where:

$C_{a(i)}(t)$ is the quantity of degradable organic carbon by waste type (i), in tonnes

Q_{waste} is the total waste disposed to landfill in year t, in tonnes (Sections 5.5 – 5.8)

$F_{Stream(j)}$ is the fraction of total waste in each waste stream (j) (Section 5.9 – 5.10)

$F_{(i)}$ is the fraction of waste mix type (i) in each stream (j) (Section 5.11)

$DOC_{(i)}$ is the fraction of degradable organic carbon by waste type (i) (Section 5.12)

Sections 5.5 – 5.8 set out the criterion available for the data for total waste volumes received that is required for the estimation of emissions using the IPCC Tier 2 FOD model. The data may, in principle, be classified according to similar criteria set out for the classification of quantities of fuels and other raw materials.

5.5 Criteria for estimating tonnage of total solid waste

For the purpose of estimating the tonnage of waste disposed of in a landfill, 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

Sections 5.9 – 5.10 set out data requirements for the composition of the waste data split between waste streams. Data required include tonnes of (a) municipal solid waste (b) commercial and industrial waste and (c) construction and demolition waste.

It is intended that Reporters should adopt the classifications adopted for state-based levy systems where applicable and, if not:

- class waste from transfer stations as commercial and industrial;
- class all council collections as municipal solid waste;
- class mixed load deliveries of domestic and commercial waste according to the dominant source.

(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) or (3).

(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 as follows:
  (a) municipal solid waste;
  (b) commercial and industrial waste;
  (c) construction and demolition waste.

(2) For subsection 5.9 (1), the tonnage of each waste stream must be estimated:
  (a) if the operator of the landfill is required, under a law of the State or Territory in which the landfill is located, to collect data on tonnage of waste received at the landfill according to the waste streams set out in column 2 of the following table — by using that data; or
  (b) if paragraph (a) does not apply and there is no restriction on the waste streams that can be received at the landfill — 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
3	Construction and demolition	27	40	43	57	45	10	15	43

(3) For subsection 5.9 (1), if the landfill is only permitted to receive:
  (a) non-putrescible waste; or
  (b) commercial and industrial waste and construction and demolition waste;

the waste may be assumed to consist only of commercial and industrial waste and construction and demolition waste.

(4) If subsection (3) applies, the tonnage of each waste stream must be estimated 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	Commercial and industrial waste	61	38	25	23	30	77	74	25
2	Construction and demolition waste	39	62	75	77	70	23	26	75

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) inert waste (including concrete, metal, plastic and glass).

(2) The percentage of the total waste tonnage for each waste mix type mentioned in column 2 of an item in the following table must be estimated by using:
- (a) sampling techniques specified in:
  - (i) waste audit guidelines issued by the State or Territory in which the landfill is located; or
  - (ii) if no guidelines have been issued by the State or Territory in which the landfill is located — ASTM 5231-92 (Reapproved 2008) or an equivalent Australian or international standard; or
- (b) the tonnage of each waste mix type received at the landfill estimated in accordance with the criteria set out in section 5.5; or
- (c) subject to subsection 5.11 (3), the default waste stream percentages in columns 3, 4 and 5 for the item for each waste mix type.

Item	Waste mix type	Municipal solid waste default %	Commercial and industrial waste default %	Construction and demolition waste default %
1	Food	35	21.5	0
2	Paper and paper board	13	15.5	3
3	Garden and park	16.5	4	2
4	Wood and wood waste	1	12.5	6
5	Textiles	1.5	4	0
6	Sludge	0	1.5	0
7	Nappies	4	0	0
8	Rubber and Leather	1	3.5	0
9	Inert waste (including concrete, metal, plastic and glass)	28	37.5	89

(3) If the licence or other authorisation authorising the operation of the landfill restricts the waste mix types (***restricted waste mix type***) that may be received at the landfill, the percentage of the total waste volume for each waste mix type mentioned in column 2 of an item of the following table (appearing immediately before the example) must be estimated:

(a) for a restricted waste mix type — by using the maximum permitted tonnage of the restricted waste mix type received at the landfill as a percentage of the total waste received at the landfill; and

(b) for each waste mix type that is not a restricted waste mix type (***unrestricted waste mix type***) — by adjusting the default percentages in columns 3, 4 and 5 of the following table for the item for each unrestricted waste mix type in accordance with the following formula:

$$W_{mtuadj} = W_{mtu} + \frac{\left(W_{mtr} - W_{mtrmax}\right) \times W_{mtu}}{\sum W_{mtu}}$$

where:

W_{mtuadj} is the adjusted percentage for each unrestricted waste mix type.

W_{mtu} is the default percentage for each unrestricted waste mix type in columns 3, 4 and 5 of the table appearing immediately before the example.

W_{mtr} is the default percentage for each restricted waste mix type in columns 3, 4 and 5 of the table appearing immediately before the example.

W_{mtrmax} is the maximum percentage for each restricted waste mix type.

$\sum$ means sum the results for each unrestricted waste mix type.

Item	Waste mix type	Municipal solid waste default %	Commercial and industrial waste default %	Construction and demolition waste default %
1	Food	35	21.5	0
2	Paper and paper board	13	15.5	3
3	Garden and park	16.5	4	2
4	Wood and wood waste	1	12.5	6
5	Textiles	1.5	4	0
6	Sludge	0	1.5	0
7	Nappies	4	0	0
8	Rubber and Leather	1	3.5	0
9	Inert waste (including concrete, metal, plastic and glass)	28	37.5	89

Example A landfill in a State is licensed only to receive commercial and industrial waste. A condition of the licence is that the landfill is restricted to receiving no more than 5% (W_{mtrmax} = 5%) food waste in its deliveries. The landfill operator accounts for this restriction by using the formula for each unrestricted waste type (W_{mtu}) in the table above. So, for paper and paper board waste, the calculation is:

$$W_{mtuadj} = 15.5 + \frac{(21.5 - 5) \times 15.5}{(15.5 + 4 + 12.5 + 4 + 1.5 + 3.5 + 37.5)}$$
$$= 18.8$$

The operator would continue to use the formula for each unrestricted waste mix type. For the restricted waste mix type the percentage used is W_{mtrmax}.

The following table sets out all the relevant variables and results for this example.

Waste mix type	W_{mtu}	W_{mtr}	W_{mtrmax}	Wmt_{adj}
Food		21.5%	5.0%	
Paper and paper board	15.5%			18.8%
Garden and park	4.0%			4.8%
Wood and wood waste	12.5%			15.1%
Textiles	4.0%			4.8%
Sludge	1.5%			1.8%
Nappies	0.0%			0.0%
Rubber and Leather	3.5%			4.2%
Inert waste (including concrete, metal, plastic and glass)	37.5%			45.4%

5.11A Certain waste to be deducted from waste received at landfill when estimating waste disposed in landfill

(1) When estimating the tonnage of waste by waste mix type disposed of in the landfill, the tonnage of the following waste is to be deducted from the estimates of waste received at the landfill:

(a) waste that is taken from the landfill for recycling or biological treatment;

(b) waste that is received at the landfill for recycling or biological treatment at the landfill site;

(c) inert waste that is used at the landfill for construction purposes, daily cover purposes, intermediate cover purposes or final capping and cover purposes..

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	Inert waste (including concrete, metal, plastic and glass)	0.00

5.13 Opening stock of degradable organic carbon

The calculation of the opening stock of carbon in a landfill in any given year requires historical data on quantities and composition of waste sent to landfill in all prior years of the landfill's operation. These data may not be available in all instances. Section 5.13 sets out the methods that can be applied in determining the opening stock of carbon.

(1) 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 and estimated in accordance with section 5.5) disposed of in 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 disposed of in the landfill over the lifetime of the landfill until the start of the first reporting period for the landfill, worked out in accordance with subsection (2);

(iii) the State or Territory in which the landfill is located.

(2) For subparagraph (1) (b) (ii), the estimated annual tonnage of waste is to be worked out:

(a) by using the average annual tonnage of solid waste disposed of in the landfill for the years for which data is available; or

(b) by conducting a volumetric survey of the landfill in accordance with subsection (3).

(3) For paragraph (2) (b), the survey:

(a) must be a ground based survey or an aerial survey: and

(b) must be conducted by a qualified surveyor.

(4) For the volumetric survey, the volume of waste is to be converted to mass by using the following volume to mass conversion factors:

(a) the landfill volume to mass conversion factors that were used during the most recent reporting year in order to comply with a landfill reporting requirement of the State or Territory in which the landfill is located; or

(b) if thefactors mentioned in paragraph (a) were not used during the most recent reporting year in order to comply with a landfill reporting requirement of the State or Territory in which the landfill is located — the volume to mass conversion factors specified in column 3 of an item in the following table for a waste stream specified in column 2 of the item:

Item	Waste stream	Volume to mass conversion factor
1	Municipal solid waste	1.1 tonnes per cubic metre
2	Commercial and industrial waste	1.1 tonnes per cubic metre
3	Construction and demolition waste	1.1 tonnes per cubic metre

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

Item	State/Territory	Waste mix type	k values
		Nappies	0.07
		Rubber and Leather	0.07

Example: Calculation of emissions from solid waste disposal

A facility constituted by a managed landfill accepting municipal solid waste uses the IPCC FOD model to determine that the emissions ($CH_{4\ gen}$) from the facility are 28,493 tonnes of CO_2-e during the year. Additionally 1,000,000 m^3 of methane has been captured at the facility (Q_{cap}) during the year for combustion. On this basis $\boldsymbol{\gamma(Q_{cap} + Q_{flared} + Q_{tr})}/CH_{4\ gen}$ is assessed to be 50% therefore according to section 5.4 – subsection 2 of the Determination, CH_4* is taken to equal $CH_{4\ gen}$.

The reporter elects to use Method 1 (5.2.2 in the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*) for methane released from landfills. Emissions are estimated as follows:

$$E_j = (CH_4 * - \gamma(Q_{cap} + Q_{flared} + Q_{tr})) \times (1\text{-}OF)$$

where:

$\boldsymbol{E_j}$ is emissions of methane (CO_2-e) released by the landfill during the year.
$\boldsymbol{CH_4}$ * is the estimated quantity of methane in landfill gas generated by the landfill during the year.
$\boldsymbol{\gamma}$ is the factor 6.784 x 10^{-4} x 21 converting cubic metres to CO_2-e tonnes.
$\boldsymbol{Q_{cap}}$ is the quantity of methane in landfill gas captured for combustion from the landfill during the year and measured in cubic metres.
$\boldsymbol{Q_{flared}}$ is the quantity of methane in landfill gas flared from the landfill during the year and measured in cubic metres.
$\boldsymbol{Q_{tr}}$ is the quantity of methane in landfill gas transferred out of the landfill during the year and measured in cubic metres.
OF is the oxidation factor (0.1) for near-surface methane in the landfill.

Therefore, to calculate emissions of methane in CO_2 e tonnes :

Total methane generated during the year as estimated using the FOD model = 28,493 tonnes CO_2-e

$$E_j = (CH_4* - \gamma(Q_{cap} + Q_{flared} + Q_{tr})) \times (1\text{-}OF)$$
$$= (28{,}493 - 6.784\text{x}10^{-4} \mathbf{\ x\ 21\ x}\ (1{,}000{,}000 + 0 + 0)) \times (1\text{-}0.1)$$

Total emissions of methane = 12,822 t CO_2-e

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)

Section 5.15 sets out Method 2, which is based on the method published in the *IPCC 2000 Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.*

(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 x 10^{-4} x 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 the Tier 2 first order decay model (the *Tier 2 FOD model*) in Volume 5, Chapter 3 of the 2006 IPCC Guidelines.

(3) In calculating CH_{4gen} for the purposes of subsection (2), the methane generation constant (***k***) must be estimated by:

(a) selecting a representative zone at the landfill in accordance with sections 5.16 to 5.17B, from which estimates of methane generation are to be obtained; and

(b) using the formula in section 5.17L.

(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 Requirements for calculating the methane generation constant (k)

5.16 Procedures for selecting representative zone

For paragraph 5.13 (3) (a), the operator of the landfill must select a representative zone in accordance with sections 5.17 to 5.17B for the purpose of estimating the methane generated from the landfill.

5.17 Preparation of site plan

(1) Before selecting a representative zone, the operator must prepare a site plan of the landfill.

(2) The site plan must be consistent with the provisions of these technical guidelines relating to landfill site plans.

Technical Guidelines relating to landfill site plans

The operator of the landfill must prepare a site plan prior to the commencement of the use of method 2 that must include the following information:

a) a description of basic site characteristics:

- the planned life of the facility and permitted volumes of waste disposal; the exact boundaries of the waste disposal area;
- containment design (liner and capping);
- fill process (for example, phased or cell; landfill or landraise);
- sideslopes and edges;
- any fissures or weak points in the cap where emissions may be high; and

b) spatial mapping of permanent and temporary capped zones and uncapped zones; and

c) spatial mapping of volumes, mass and age of waste disposed at the facility; and

d) description of gas control systems:

- locations of wells and their capacity and other relevant attributes;
- gas monitoring points;
- density of well sub-systems;

- description of flares (location, timing and gas capacities); and

e) leachate management systems;

- leachate towers, sumps, risers systems (including recirculation)
- leachate monitoring points
- presence of former co-disposal systems (eg liquid disposal trenches); and

f) any other features of the facility that could impact on flux box locations or the capacity of a representative zone or to be representative of facility.

5.17A Representative zone

(1) After preparing a site plan, the operator of the landfill must select a representative zone at the landfill.

(2) The representative zone must be a single, contiguous area within the landfill and the methane generated from the representative zone must be representative of the methane that is generated at the landfill

(3) The representative zone must cover an area of at least 1 hectare and must contain a sufficient number of operating gas collection wells to enable accurate and representative estimates to be obtained of the methane being generated from the zone.

(4) The representative zone must contain only waste that has been undisturbed:

(a) for at least 12 months before any methane generation is measured under section 5.17H; or

(b)in the case of a representative zone that is on landfill that recirculates leachate or adds moisture through the waste to promote methane generation — for the period determined by an independent expert. (5) The following characteristics of the representative zone must be uniform and must be representative of the landfill so that the estimates of the methane that is generated from the zone comply with section 1.13:

(a) the depth of waste in the zone; and

(b) moisture levels in the zone.

(c) the composition of waste mix types in the zone.

5.17B Independent verification

(1) After selecting a representative zone, the operator must arrange for an independent expert to certify, in writing, that:

(a) the representative zone is representative of the landfill; and

(b) the boundaries of the zone are appropriate for the purpose of obtaining accurate and representative estimates of the methane being generated from the zone.

(2) The independent expert must also prepare a written report for the zone.

(3) The report must include the details specified in these technical guidelines in relation to expert reports.

Expert reports on representative zones

The operator of the facility must enter into a written agreement with the expert, which may be by an exchange of letters, specifying the terms governing the preparation of a report providing an assessment on the selection of the representative zone.

The written report must contain all information which the operator and others likely to rely on the report would reasonably require, and reasonably expect to find in the report, for the purpose of making an informed decision about the representativeness of the selected zone.

The report should include:

(a) a description of the relevant aspects of the facility;

(b) an account of the material history of the facility, including the volume, mass, age and types of waste in the representative zone;

(c) an assessment as to the degree of uniformity of moisture levels between the representative zone and the remainder of the landfill, taking into account the technologies and processes used in the representative zone that affect moisture levels compared with other parts of the facility including the use of leachate recirculation and cell size; and

(d) an assessment of the degree of uniformity of the depth of waste, taking into account the results of volumetric surveys conducted for the site, if any have been conducted.

The independent expert must also provide an assessment as to whether the boundaries of the representative zone are appropriate. The boundaries of the zone should define the volume of waste that is generating the gas captured by the collection system within the representative zone.

For any given point on the boundary, the location of the boundary should be located by determining a distance between two adjacent wells - one well internal to the selected area and one well external to the selected area - which is proportional to the relative landfill gas flow rate of each well recorded over the test period. The data used must have been recorded during periods of operation of the collection system that reflect normal operating conditions (ie consistent with the operation of the system on days of flux box measurement). There must be no significant net flow of landfill gas across the representative zone boundary when the measurements are made.

For zones with vertical well systems in place, the boundary can be assumed to be a vertical surface extending from the landfill surface to the base of the waste.

For zones with horizontal well systems in place the representative zone may be estimated on the zone of influence of the horizontal well system.

Detailed technical information and data should be included in the report if their understanding is important to the assessment. Explanations of unusual or new technical processes and activities that may be material to the understanding of the assessment should be included, where commercial confidentiality considerations allow.

Experts must not rely uncritically on the data and other information provided, either by the operator of the facility or obtained otherwise. They must undertake suitable checks, enquiries, analyses and verification procedures to establish reasonable grounds for establishing the soundness of the contents and conclusions of the report.

The expert must either certify that the representative zone has been selected in accordance with these *Guidelines* and the *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009,* or the contrary, and personally sign the report.

5.17C Estimation of waste and degradable organic content in representative zone

The amount of waste, and the amount of degradable organic content in the waste, disposed of in the representative zone must be estimated in accordance with sections 5.5 to 5.12 for each reporting year that waste is disposed of in the representative zone.

5.17D Estimation of gas collected at the representative zone

(1) The operator of the landfill must estimate the total amount, and concentration, of landfill gas (measured in tonnes of methane per year) collected by all of the landfill gas collection wells located within the representative zone.

(2) Measurement of the landfill gas flow rate for each well must be undertaken in accordance Division 2.3.6.

(3) The methane concentration of the landfill gas from the representative zone:

(a) may be estimated from measurements [of landfill gas] obtained at each gas collection well located within the representative zone using industry standard landfill gas analysers that are calibrated to the manufacturer's specifications; or

(b) may be assumed to be the methane concentration for the landfill as analysed under Subdivision 2.3.3.2.

(4) Data about the methane gas flow rates at each well in the representative zone must be:

(a) the data used for operational purposes; and

(b) recorded at least once a week for a period of at least 12 months.

(5) Fuel flow meter equipment and gas composition monitor equipment used to measure and analyse the landfill gas must be calibrated in accordance with:

(a) a standard specified in section 2.24 or an equivalent standard; or

(b) the calibration procedures specified, and at the frequencies recommended, by the manufacturer of the equipment.

(6) Fuel flow meter equipment and gas composition monitor equipment must be recalibrated:

(a) at the frequency specified by the manufacturer of the equipment; or

(b) if the manufacturer does not specify a recalibration period for the equipment — annually.

(7) Estimates of gas flow must be converted from cubic metres to mass by using the formula in subsection 1.21 (1).

5.17E Estimating methane generated but not collected in the representative zone

(1) The operator must estimate the amount of methane generated in the representative zone that is not collected by the collection wells in the zone.

(2) Estimates must be obtained by using the procedures in sections 5.17F to 5.17H.

5.17F Walkover survey

(1) The operator of the landfill must arrange for an independent expert to conduct a walkover survey of the representative zone using a portable gas measurement device in order to:

(a) determine the near surface gas concentrations in the representative zone and in the immediately surrounding area; and

(b) identify locations within the representative zone:

(i) that have high methane emissions; and

(ii) where flux boxes need to be installed in accordance with section 5.17G in order to obtain the most accurate and representative measurements of methane emissions.

(2) The portable gas measurement device must be capable of detecting hydrocarbons at 10 parts per million.

Note The publication entitled *Guidance on monitoring landfill gas surface emissions* published by the Environment Agency of the United Kingdom in September 2004 contains guidance on how to conduct a walkover survey.

5.17G Installation of flux boxes in representative zone

(1) After the walkover survey has been completed, the operator of the landfill must arrange for the installation of flux boxes in the representative zone.

(2) The number of flux boxes must be at least the minimum number identified during the walkover survey.

(3) The flux boxes must be installed at the locations identified in the walkover survey.

(4) If the operator installs the flux boxes, the operator must ensure that an independent expert certifies, in writing, that the boxes have been correctly installed and located.

(5) If the operator arranges for some other person to install the flux boxes, the other person must be an independent expert.

(6) The minimum number of flux boxes is to be determined by using the following formula:

$$6+0.15 \times \sqrt{Z}$$

where:

Z is the size of the representative zone in square metres.

Note AS/NZS 4323.4:2009 and the publication entitled *Guidance on monitoring landfill gas surface emissions* published by the Environment Agency of the United Kingdom in September 2004 contains guidance on how to design and install flux boxes.

5.17H Flux box measurements

(1) After the flux boxes have been installed in the representative zone, the operator must:

(a) measure the flow of methane in each flux box and arrange for an independent expert to certify, in writing, that the measurements are accurate and were correctly measured; or

(b) arrange for an independent expert to take the measurements.

Note AS/NZS 4323.4:2009 and the publication entitled *Guidance on monitoring landfill gas surface emissions* published by the Environment Agency of the United Kingdom in September 2004 contains guidance on how to take measurements in flux boxes.

Expert reports on emission measurements

The operator of the facility must enter into a written agreement with the expert, which may be by an exchange of letters, specifying the terms governing the preparation of a report on the estimation of emissions from the representative zone.

The written report must contain all information which the operator and others likely to rely on the report would reasonably require, and reasonably expect to find in the report, for the purpose of making an informed decision about the estimated emissions from the representative zone. The report must include:

(a) sufficient information about the method(s) used to conduct the walkover and flux box surveys so that another expert could understand the procedures used and analyses undertaken. This information must include:

- a description of the precise boundaries of the representative zone, and of any recalculations to the estimated boundaries made by the expert for the conduct of the flux box test;
- a description of the facility and any features which may have affected placement of flux boxes;
- dates and times at which measurements were undertaken;
- details about the precise location of flux boxes operated for the measurement process and any relevant information that may have affected the placement of the flux boxes;

(b) sufficient information about the results obtained so that another expert could understand the procedures used and replicate the estimates. This information must include:

- data on all measurements undertaken, and methods used to determine a gas flow rate estimate at individual flux boxes; and
- details of the geospatial techniques used and the calculations made to estimate the flow of methane emissions from the representative zone from the measurements taken at individual flux boxes.

(c) a qualitative assessment of the accuracy of the measurements obtained. This assessment must take account of relevant conditions that may have affected the measurements taken. The report must include data on:

- rainfall;
- barometric pressure;
- wind speed; and
- temperature;

at the facility or as otherwise specified for the duration of the measurement period. All relevant data for the immediate period prior to the measurements being undertaken, as considered appropriate by the expert, must also be recorded.

(d) a review of any other matters that are material to the report;

(e) information regarding all sources of data used;

(f) a concise summary setting out the key data and important assumptions made and the conclusions drawn by the expert.

Detailed technical information and data should be included in the report if their understanding is important to the assessment. Explanations of unusual or new technical processes and activities that may be material to the understanding of the assessment should be included, where commercial confidentiality considerations allow.

Experts must not rely uncritically on the data and other information provided, either by the operator of the facility or obtained otherwise. They must undertake suitable checks, enquiries, analyses and verification procedures to establish reasonable grounds for establishing the soundness of the contents and conclusions of the report.

The expert must certify that the estimate of emissions from the representative zone has been prepared in accordance with these Guidelines and with the *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009* and personally sign the report.

Estimation of the flow of methane at an individual flux box

(2) The flow of methane from each flux box must be calculated in accordance with the following formula:

Q = V x (dc/dt)/A

where:

Q is the flow density of the gas in the flux box measured in milligrams of methane per square metre per second.

V is the volume of the flux box measured in cubic metres.

dc/dt is the rate of change of gas concentration in the flux boxes over time, measured in milligrams per cubic metre per second.

A is the area covered by the flux box measured in square metres.

Estimation of methane generation not collected from the representative zone

(3) The total gas flow rate for the representative zone is to be obtained by using geospatial interpolation techniques. The total gas flow rate for the zone is obtained by the use of tributary arithmetic mean, kriging mean or other geospatial interpolation techniques. If the flow of emissions is uniform, then these techniques revert to a simple averaging process.

(4) The amount of methane generated in the representative zone, and not collected, must be estimated by dividing the total gas flow rate obtained in subsection (3) by (1-OF) where OF is defined in 5.15.

(5) The measurement of methane obtained under the formula in subsection (4) must be converted from milligrams of methane per square metre per second to tonnes of methane for the surface area of the representative zone for the reporting year.

(6) Estimates of gas flow must be converted from cubic metres to mass by using the formula in subsection 1.21 (1).

5.17I When flux box measurements must be taken

(1) Flux box measurements must be taken during the normal operating times of the gas collection wells in the representative zone.

(2) The measurements must be completed within 3 days.

5.17J Restrictions on taking flux box measurements

(1) Flux box measurements must not be taken:
   (a) within 2 days of heavy rainfall over the representative area; or
   (b) if barometric pressure at the landfill site is rising or falling sharply; or
   (c) during frost conditions; or
   (d) in any other meteorological conditions that may significantly affect the accuracy of the measurements; or
   (e) in areas where there is standing water.

Note AS/NZS 4323.4:2009 and the publication entitled *Guidance on monitoring landfill gas surface emissions* published by the Environment Agency of the United Kingdom in September 2004 contains guidance on good measurement practice.

(2) For subsection (1), there is ***heavy rainfall*** over a representative area on any day of a month if the amount of rain that is recorded:
   (a) at the landfill or
   (b) if rainfall is not recorded at the landfill — at the nearest Bureau of Meteorology weather station to the landfill;

exceeds the heavy rainfall benchmark, as calculated in accordance with the following formula:

HRF = 2 x RF/MRD

where

HRF is the heavy rainfall benchmark.

RF is the mean monthly rainfall for the month at the landfill or nearest Bureau of Meteorology weather station.

MRD is the mean rainfall days for the month at the nearest Bureau of Meteorology weather station as recorded in the publication published by the Bureau of Meteorology and known as *Climate Statistics for Australian locations*. This document is available at http://www.bom.gov.au/climate/cdo/about/about-stats.shtml.

5.17K Frequency of measurement

The measurement of emissions by flux boxes must be undertaken on a quarterly basis for a period of at least 12 months.

The 12 month flux-box measurement period should be the same 12 month period in which the measurements of landfill gas collection in the well system are undertaken.

5.17L Calculating the methane generation constant (*k*)

(1) For paragraph 5.15 (3) (b), the formula for calculating the methane generation constant (***k***) is as follows:

$$Q_z - \left(k \times Q_{waste} \times L_0 \times e^{-k \times A_{avg}}\right) = 0$$

where:

Q_z is the gas flow rate for the representative zone, measured in tonnes per year, and is the sum of:

(a) the total amount of methane estimated under section 5.17D and collected at the collection wells in the representative zone; and

(b) the total amount of methane generated from the representative zone as obtained under subsection 5.17H (5).

k is the methane generation constant.

Q_{waste} is the total waste disposed of in the representative zone, measured in tonnes and estimated in accordance with section 5.17C.

L_o is the methane generation potential of the waste in the representative zone worked out under subsection (2) and measured in tonnes of methane per tonne of waste disposed.

e is the base number for natural logarithms (2.718).

A_{avg} is the average age of the waste in the representative zone, measured in years.

(2) For subsection (1), the methane generation potential (L_o) for waste disposed of in a representative zone of a landfill during a year is to be worked out using the following formula:

$$\left(\frac{C_a}{Q_{waste}}\right) \times DOC_F \times MCF \times F \times 1.336$$

where:

C_a is the is the quantity of degradable organic carbon in waste disposed of in the representative zone, measured in tonnes and estimated in accordance with section 5.17C.

Q_{waste} is the total waste disposed in the representative zone, measured in tonnes and estimated under section 5.17C.

DOC_F is the fraction of degradable organic carbon dissimilated and is equal to 0.5.

MCF is the methane correction factor for aerobic decomposition and is equal to 1.

F is the fraction by volume of methane in landfill gas as estimated in accordance with section 5.17D and collected from the representative zone.

1.336 is the factor to convert carbon to methane.

(3) For the formula in subsection (1), it is sufficient if the left-hand side of the formula is within ±0.001 of zero.

Example: Calculation of emissions from solid waste disposal – Method 2

A facility constituted by a managed landfill accepting food waste only elects to use method 2 to determine a site-specific decay rate constant. The total amount of food waste in the representative zone is estimated at 10,000 tonnes and has been undisturbed under a final cover for a period of 1 year (with an average age of 1 year).

The combined methane generation as measured from the collection system and flux-box testing (taking account of the oxidation of methane in the landfill cap) in the representative zone was estimated at 28.3 tonnes of methane over the year.

With this information, the landfill operator can proceed to calculate a site-specific 'k' value using the equation:

$$Q_z\text{-}(k \times Q_{waste} \times L_o \times e^{-k \times Aavg}) \quad (1)$$

where:

Q_z is the combined methane generation for the representative zone
k is the methane generation constant.
Q_{waste} is the total waste disposed in the representative zone measured in tonnes
e is the base number for natural logarithms (2.718).
A_{avg} is the average age of the waste in the representative zone measured in years.
L_o is the methane generation potential of the waste in the representative zone and calculated according to:

$$\{C_a/Q_{waste}\} \times DOC_F \times MCF \times F \times 1.336$$

where:

C_a is the quantity of degradable organic carbon in waste disposed of in the representative zone measured in tonnes.
Q_{waste} is the total waste disposed in the representative zone measured in tonnes.
DOC_F is the fraction of degradable organic carbon dissimilated and equal to 0.5.
MCF is the methane correction factor for aerobic decomposition and is equal to 1.
F is the fraction by volume of methane in landfill gas collected from the representative zone.
1.336 is the factor to convert carbon to methane.

Firstly, the landfill operator uses information about the waste composition to calculate L_o:

C_a = 1,500
Q_{waste} = 10,000
DOC_F = 0.5
MCF = 1
F = 0.5

L_o = (1,500/10,000) x 0.5 x 1 x 0.5 x 1.336 = 0.05 tonnes of methane per tonne of waste.

The estimate for L_o is then used in equation (1) which is to be solved for 'k'. The landfill operator chooses a value for 'k' which makes the left hand side of the equation equal zero within ±0.001. If the estimate of k does not produce this result, the process is repeated until a suitable value for 'k' is found.

In this example, the value that solves for 'k' is 0.06 and:

$Q_z = 28.3$
$Q_{waste} = 10{,}000$
$L_o = 0.05$
$A_{avg} = 1$

Thus:

$$28.3 - (0.06 \times 10{,}000 \times 0.05 \times e^{(-0.06 \times 1)}) = 0.000$$

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)

Section 5.18 sets out Method 3, which is the same as for Method 2, except that the sampling requirements of the US Environment Protection Agency *Method 2E*, *Determination of landfill gas flow production rates* are applied.

(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:
   (a) paragraph 5.15 (3) (a) does not apply; and
   (b) the gas flow rate must be estimated from sampling undertaken 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

Sections 5.19-5.21 set out Methods 1, 2 and 3 for the flaring of methane in landfill gas. Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the gas composition of the fuel more closely in order to estimate the quantity of methane flared more accurately.

(1) For subparagraph 5.3 (b) (i), method 1 is:

$$E_{j\ flared} = Q_{flared} \times EC_i \times \frac{EF_{ij}}{1\,000}$$

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

Section 5.22 sets out Method 1 for emissions released from the Biological treatment of solid waste production. The method to be used is described in *IPCC 2006 Guidelines for National Greenhouse Gas Inventories Volume 5, Chapter 4.*

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 – equations 4.1 and 4.2:

EQUATION 4.1: Methane emissions from biological treatment

$$CH_4\ Emissions = \Sigma_i (Q_i \times EF_i) - R$$

Where:

CH_4 Emissions = total CH_4 emissions in inventory year, tonnes CO_2-e
Q_i = mass of wet organic waste treated by biological treatment type *i*, tonnes
EF = emission factor for treatment *i*, tonnes CO_2-e/tonne of wet waste treated and equal to:

- for composting: 0.08
- for anaerobic digestion: 0.02

R = total amount of CH_4 recovered in inventory year, tonnes CO_2-e

EQUATION 4.2: Nitrous oxide emissions from biological treatment

$$N_2O\ Emissions = \Sigma_i (Q_i \times EF_i)$$

Where:
N_2O Emissions = total N_2O emissions in inventory year, tonnes of CO_2-e
Q_i = mass of wet organic waste treated by biological treatment type *i*, tonnes
EF = emission factor for treatment *i*, tonnes of CO_2-e/tonnes of wet waste treated and equal to:

- for composting: 0.09
- for anaerobic digestion: 0.0

Part 5.3 Wastewater handling (domestic and commercial)

Division 5.3.1 Preliminary

5.23 Application

(1) This Part applies to emissions released from the decomposition of organic material, nitrification and denitrification processes or flaring of sludge biogas resulting from the handling of domestic or commercial wastewater through:

(a) treatment in wastewater collection and treatment systems; or

(b) discharge into surface waters.

(2) In this section, ***domestic or commercial wastewater*** means liquid wastes and sludge (including human waste) from housing or commercial premises.

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

Summary of available methods by emissions of gas type (j)

	CO_2	CH_4	N_2O
Domestic and Commercial waste water management			
Method 1	NA	Section 5.25	Section 5.31
Method 2	NA	Section 5.26	Section 5.32
Method 3	NA	Section 5.30	Section 5.36
Method 4	NA	NA	NA
Methane flared from the operation of the facility			
Method 1	NA	Section 5.37	Section 5.37
Method 2	NA	Section 5.38	Section 5.38
Method 3	NA	Section 5.39	Section 5.39
Method 4	NA	NA	NA

NA = Not available. NO = Not occurring.

(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 emissions 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)

Section 5.25 sets out Method 1 for wastewater handling – domestic and commercial.

Method 1 for wastewater handling is based on the *National Greenhouse Accounts* methods, except in certain circumstances, specified below.

Total greenhouse gas emissions from domestic and commercial wastewater are the sum of emissions from wastewater treatment and sludge treatment. The total quantity

of wastewater treated depends on the size of the population that is generating wastewater.

Method 1 provides a method for estimating emissions in the absence of data on Chemical Oxygen Demand (COD) or Biochemical Oxygen Demand (BOD) estimates of on-site wastewater and sludge.

Section 5.25 sets out that under certain specific circumstances an alternative estimation approach should apply. These circumstances are for facilities that capture methane generated by the wastewater handling and where the estimates of the quantity of methane captured for combustion (either at the facility or elsewhere) or flaring exceed 75 per cent of the estimated emissions generated from the wastewater from the facility according to the application of the emissions generation model.

The method to be applied in these circumstances is as for the solid waste disposal method set out in section 5.4 with the exception of subsection (5) which provides a calculation specific to wastewater handling based on chemical oxygen demand (COD) in the wastewater and uses methane correction factors (F_{wan} and F_{slan}) for the wastewater and sludge. The methane correction factors are the fractions of COD anaerobically treated by the plant. Methane will only be generated through anaerobic treatment of the COD and emissions estimates must be corrected to eliminate any COD that is not anaerobically treated.

As for solid waste disposal, it is intended that Reporters will be able to use direct emissions monitoring systems to establish higher capture efficiencies and to establish emissions directly. This will require the development of direct monitoring methods. None have been specified in this Determination. Further development work and consultation is required to establish the appropriateness of various monitoring techniques before their inclusion.

(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:

$$\frac{\gamma\ (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

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:

$$\frac{\gamma\ (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is greater than 0.75 then:

$$CH_4^* = \gamma\left(Q_{cap} + Q_{flared} + Q_{tr}\right) \times \left(\frac{1}{0.75}\right)$$

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 tonnes 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)

Division 5.3.3 sets out Method 2 for the estimation of methane emissions from wastewater handling, which requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using general sampling provisions for the Guidelines and analysis conducted in accordance with listed Australian or international standards or an equivalent standard. It is likely that many facilities collect this data routinely for existing regulatory reasons.

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:

$$COD = 2.6 \times BOD_5$$

(2A) In applying method 1 under section 5.25, the reference to 0.75 in subsections 5.25 (2) and (3) is to read as a reference to 1.00.

(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)

Division 5.3.4 sets out Method 3 for the estimation of methane emissions from wastewater handling, which requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using sampling and analysis conducted in accordance with listed Australian or international standards or an equivalent standard.

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)

Section 5.31 sets out Method 1 for the estimation of nitrous oxide emissions.

(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:

$$N_{in} = Protein \times Frac_{Pr} \times P$$

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)

Section 5.32 to 5.35 sets out Method 2 for the estimation of nitrous oxide emissions from wastewater handling. Method 2 requires the sampling and analysis of nitrogen quantities in the wastewater and sludge in accordance with listed Australian or international standards or an equivalent standard. It is likely that many facilities collect this data routinely for regulatory reasons.

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)

Section 5.36 sets out Method 3 for the estimation of nitrous oxide emissions from wastewater handling. Method 3 is very similar to Method 2, except that sampling of the water and sludge must be undertaken in accordance with listed Australian or international standards or an equivalent standard.

(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

Sections 5.37-5.39 set out Methods 1, 2 and 3 for the flaring of gas. Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the gas composition of the fuel in order to estimate the quantity of methane flared more accurately.

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:

$$E_{j\ flared} = Q_{flared} \times EC_i \times \frac{EF_{ij}}{1\,000}$$

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 Wastewater handling (industrial)

Division 5.4.1 Preliminary

5.40 Application

(1) This Part applies to emissions released from the decomposition of organic material, nitrification and denitrification processes or flaring of sludge biogas resulting from handling of industrial wastewater through:

(a) treatment in wastewater systems; or

(b) discharge into surface waters.

(2) In this section, ***industrial wastewater*** means liquid wastes or sludge resulting from the production of a commodity, by an industry, mentioned in column 2 of an item of the table in subsection 5.42 (8).

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 generated by the relevant industries (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.

Summary of available methods, by emissions of gas type (j)

	CO_2	CH_4	N_2O
Domestic and Commercial waste water management			
Method 1	NA	Section 5.42	NO
Method 2	NA	Section 5.43	NO
Method 3	NA	Section 5.47	NO
Method 4	NA	NA	NO
Methane flared from the operation of the facility			

Method 1	NA	Section 5.48	Section 5.48
Method 2	NA	Section 5.49	Section 5.49
Method 3	NA	Section 5.50	Section 5.50
Method 4	NA	NA	NA

NA = Not available. NO = Not occurring.

(4) For incidental emissions 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)

Section 5.42 sets out Method 1 for methane emissions from wastewater handling – industrial. It is intended that this method applies to industries producing the following commodities under the applicable ANZSIC codes:

- Dairy products (ANZSIC code 113)
- Pulp, paper and paperboard (ANZSIC code 1510)
- Meat and poultry (ANZSIC codes 1111 and 1112)
- Organic chemicals (ANZSIC codes 18 and 19)
- Raw sugar (ANZSIC code 1181)
- Beer (ANZSIC code 1212)
- Wine and Other Alcoholic Beverages (ANZSIC code 1214)
- Fruit and vegetables (ANZSIC code 1140)

ANZSIC codes and descriptions of the activities included under each code can be found on the Australian Bureau of Statistics website at http://www.abs.gov.au.

Note the definition of raw sugar is as follows:

> ***raw sugar*** has the meaning given by Chapter 17, Section IV, Schedule 3 of the *Customs Tariff Act 1995*

The following is an excerpt from Chapter 17, Section IV, Schedule 3 of the *Customs Tariff Act 1995*

> " "raw sugar" means sugar whose content of sucrose by weight, in the dry state, corresponds to a polarimeter reading of less than 99.55."

As for domestic and commercial wastewater handling facilities, Method 1 for wastewater handling is based on the *National Greenhouse Accounts* methods, except in certain circumstances.

The method to be applied in these circumstances is as for the solid waste disposal method set out in section 5.4.

As for solid waste disposal, it is intended that Reporters will be able to use direct emissions monitoring systems to establish higher capture efficiencies and to establish emissions directly. This will require the development of direct monitoring methods. None have been specified in these Guidelines. Further development work and consultation is required to establish the appropriateness of various monitoring techniques before their inclusion.

(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:

$$\frac{\gamma\,(Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

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:

$$\frac{\gamma\ (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is greater than 0.75 then:

$$CH_4^* = \gamma\left(Q_{cap} + Q_{flared} + Q_{tr}\right) \times \left(\frac{1}{0.75}\right)$$

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 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:

$$CH_{4gen} = \left[\ (\Sigma_{w,i} COD_{wi} - COD_{sl}) \times \left(F_{wan} \times \quad {}_{w\,ij}\right)\right]$$
$$+\left[(COD_{sl} - COD_{trl} - COD_{tro}) \times F_{slan} \times EF_{slij}\right]$$

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:

$Prod_i$ has the meaning given by the table in subsection 5.42 (9).

$W_{gen,i}$ 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:

$COD_{w,i}$ 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.

F_{sl} is the fraction of COD removed from wastewater as sludge by the plant during the year.

F_{wan} is the fraction of COD in wastewater 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

$EF_{w\,ij}$ is the methane emission factor for industrial wastewater.

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.

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.

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

$EF_{sl\ ij}$ is the methane emission factor for the treatment of sludge by the plant.

(6) For ***EF_{wij}*** in subsection (5), an emission factor of 5.3 CO_2-e tonnes per tonne of COD may be used.

(7) For ***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 that is produced by the industry referred to by the ANZSIC code set out in column 2 for that item:

(a) by using the default values for $W_{gen,i}$, $COD_{con,i}$ and 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 and industry	$W_{gen,i}$, default value	$COD_{con,i}$ default value	F_{wan} default value
1	Dairy product (ANZSIC code 113)	5.7	0.9	0.4
2	Pulp, paper and paperboard (ANZSIC code 1510)	26.7	0.4	0.0
3	Meat and poultry (ANZSIC codes 1111 and 1112)	13.7	6.1	0.4
4	Organic chemicals (ANZSIC codes 18 and 19)	67.0	3.0	0.1
5	Raw sugar (ANZSIC code 1181)	0.4	3.8	0.3
6	Beer (ANZSIC code 1212)	5.3	6.0	0.5
7	Wine and Other Alcoholic Beverage (ANZSIC code 1214)	23.0	1.5	0.0
8	Fruit and vegetable (ANZSIC code 1140)	20.0	0.2	1.0

(9) For subsection (5), $Prod_i$ is the amount of any commodity set out in column 2 of an item in the following table, produced by the industry set out in column 2 for that item, and measured in accordance with the corresponding units of measurement set out in column 3 for that item.

Item	Commodity and industry	Units of measurement
1	Dairy product (ANZSIC code 113)	tonne of product
2	Pulp and paper and paperboard (ANZSIC code 1510)	tonne of paper produced
3	Meat and poultry (ANZSIC codes 1111 and 1112)	tonne of product (hot standard carcass weight or live weight basis)
4	Organic chemicals (ANZSIC codes 18 and 19)	tonne of product
5	Raw sugar (ANZSIC code 1181)	tonne of raw sugar produced (raw sugar equivalent)
6	Beer (ANZSIC code 1212)	tonne of product
7	Wine and other alcoholic beverage (ANZSIC code 1214)	tonne of product
8	Fruit and vegetable (ANZSIC code 1140)	tonne of product

Division 5.4.3 Method 2 — methane released from wastewater handling (industrial)

5.43 Method 2 — methane released from wastewater handling (industrial)

Sections 5.43-5.46 set out Method 2 for wastewater handling. Method 2 requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using general sampling provisions for these Guidelines and analysis conducted in accordance with listed Australian or international standards or an equivalent standard.

(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:

$$COD = 2.6 \times BOD_5$$

(2A) In applying method 1 under section 5.42, the reference to 0.75 in subsections 5.42 (2) and (3) is to read as a reference to 1.00

(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)

Section 5.47 sets out Method 3 for wastewater handling. The Method requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using sampling and analysis conducted in accordance with listed Australian or international standards or an equivalent standard.

(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

Sections 5.48-5.50 set out Methods 1, 2 and 3 for the flaring of methane in sludge biogas. Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the gas composition of the fuel in order to estimate the quantity of methane flared more accurately.

5.48 Method 1 — flaring of methane in sludge biogas

(1) For paragraph 5.41 (2) (a), method 1 is:

$$E_{j\ flared} = Q_{flared} \times EC_i \times \frac{EF_{ij}}{1\ 000}$$

where:

$E_{j\ flared}$ 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 Waste incineration

5.51 Application

This Part applies to 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:

$\boldsymbol{E_i}$ 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.

$\boldsymbol{Q_i}$ is the quantity of waste type (***i***) incinerated by the plant during the year measured in tonnes of wet weight value in accordance with:

(a) Division 2.2.5 for solid fuels; and

(b) Division 2.3.6 for gaseous fuels; and

(c) Division 2.4.6 for liquid fuels.

$\boldsymbol{CC_i}$ is the carbon content of waste type (***i***).

$\boldsymbol{FCC_i}$ is the proportion of carbon in waste type (***i***) that is of fossil origin.

$\boldsymbol{OF_i}$ 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 3.

(3) For $\boldsymbol{CC_i}$ in subsection (1), the IPCC default of 0.60 for clinical waste must be used.

(4) For $\boldsymbol{FCC_i}$ in subsection (1), the IPCC default of 0.40 for clinical waste must be used.

(5) For $\boldsymbol{OF_i}$ in subsection (1), the IPCC default of 1.00 for clinical waste must be used.

5.53A Reporting

The corporation's report must include information for the facility in relation to greenhouse gas emissions from waste during the year and must identify:

(a) the criteria used by the corporation to estimate the amount of waste disposed for the source.

(b) the methods used by the corporation to estimate the greenhouse gas emissions from the source.

(c) the amount of each greenhouse gas that is emitted.

Additional emissions-related information that should be reported are set out in Regulation 4.17.

For the reporting of all other scope 1 emission sources, Reporters should refer to chapters 2, 4 and 5 and other parts of this chapter.

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.

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 during 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 operation of the facility that is not supplied to the network; or

(d) if the energy is electricity produced for use outside the operation of the facility other than for supply to an electricity transmission or distribution network — 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 for use outside the operation of the facility for supply 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.

An example of metering requirements applicable to a region is the *Wholesale Electricity Market Amending Rules* in Western Australia's South West Interconnected System.

The requirements above are generally sourced from definitions contained in the National Electricity Rules and current measurement requirements under the *Generator Efficiency Standards* program.

The metering requirements specified in 6.2 (3) apply to the measurement of electricity supplied to an electricity transmission and distribution network measured at the connection point to the network.

Metering requirements are not specified for the amount of electricity produced by the electricity generation unit measured at the unit's terminals or the amount supplied for use outside the facility which is not supplied to the network. Measurement of these quantities of electricity should make use of existing data and be consistent with the general principles set out in 1.13.

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.

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 Chapter 2; 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, EC_i is equal to 0.0036; or

(d) for fuels measured in gigajoules, 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.

Estimates of energy produced do not enter emission calculations and will be used for statistical purposes. Further development of these specifications may be necessary, however, depending on the development of policy in relation to emissions trading and, in particular, the use of the concept of upstream liability.

6.3A Reporting

The *National Greenhouse and Energy Reporting Regulations 2008,* Division 4.4 specifies information relating to energy production that must be included in a registered corporation's report for a reporting year if the corporation's group meets a threshold in subsection 13 (1) of the Act for that year.

If the operation of a facility of the corporation produces energy during the reporting year, the corporation's report must include information for the facility identifying the type and amount of energy produced during the reporting year.

If the operation of a facility of the corporation produces electricity, the corporation must report whether the electricity was produced using:

a) thermal generation; or

b) geothermal generation; or

c) solar generation; or

d) wind generation; or

e) water generation; or

f) biogas generation.

The corporation's report must identify the amount of the electricity that was produced for use in the facility and produced for use outside the facility.

Information required to be reported, relating to energy production are detailed in the following tables:

Item	Fuels and other energy commodities	Energy production
1	Black coal (other than that used to produce coke)	
2	Brown coal	
3	Coking coal	
4	Brown coal briquettes	
5	Coke oven coke	
6	Coal tar	
7	Solid fossil fuels other than those mentioned in items 1 to 5	
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	
10	Dry wood	
11	Green and air dried wood	
12	Sulphite lyes	
13	Bagasse	
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	
15	Charcoal	
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	
17	Natural gas distributed in a pipeline	
18	Coal seam methane that is captured for combustion	
19	Coal mine waste gas that is captured for combustion	
20	Compressed natural gas that has reverted to standard conditions	
21	Unprocessed natural gas	
22	Ethane	
23	Coke oven gas	
24	Blast furnace gas	
25	Town gas	
26	Liquefied natural gas	
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	
28	Landfill biogas that is captured for combustion (methane only)	
29	Sludge biogas that is captured for combustion (methane only)	
30	A biogas that is captured for combustion, other than those mentioned in items 28 and 29 (methane only)	
31	Petroleum based oils (other than petroleum based oil used as fuel)	
32	Petroleum based greases	
33	Crude oil including crude oil condensates	

Item	Fuels and other energy commodities	Energy production
34	Other natural gas liquids	
35	Gasoline (other than for use as fuel in an aircraft)	
36	Gasoline for use as fuel in an aircraft	
37	Kerosene (other than for use as fuel in an aircraft)	
38	Kerosene for use as fuel in an aircraft	
39	Heating oil	
40	Diesel oil	
41	Fuel oil	
42	Liquefied aromatic hydrocarbons	
43	Solvents if mineral turpentine or white spirits	
44	Liquefied petroleum gas	
45	Naphtha	
46	Petroleum coke	
47	Refinery gas and liquids	
48	Refinery coke	
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.	
50	Biodiesel	
51	Ethanol for use as a fuel in an internal combustion engine	
52	Biofuels other than those mentioned in items 50 and 51	
71	Solvents if mineral turpentine or white spirits	
72	Bitumen	
73	Waxes	
74	Carbon black if used as a petrochemical feedstock	
75	Ethylene if used as a petrochemical feedstock	
76	Petrochemical feedstock other than those mentioned in items 74 and 75	
84	Sulphur	
85	Uranium	
86	Hydrogen	
	Energy commodities other than those mentioned above and in the form of steam, compressed air or waste gas acquired either to produce heat or for another purpose	

Reporting Table – Electricity Generation Type

	Electricity produced
Thermal generation	
Geothermal generation	
Solar generation	
Wind generation	
Water generation	
Biogas generation	

Reporting Table – Electricity Use

		Electricity produced
Electricity produced for use in the facility		
Electricity produced for use outside the facility	Electricity supplied for use outside an electricity transmission or distribution network	
	Electricity supplied to an electricity transmission or distribution network	

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.

Calculating the energy content of fuels and energy commodities consumed is an intermediate step in the estimation of emissions from fuel combustion using methods 1, 2 or 3 in Chapter 2. Consequently this data will serve the dual purpose of providing an estimation of energy consumed and a step in the estimation of emissions.

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:

$\boldsymbol{Z_i}$ is the energy content of fuel type (***i***) consumed during the year and measured in gigajoules.

$\boldsymbol{Q_i}$ 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.

$\boldsymbol{EC_i}$, is the energy content factor of fuel type ***(i)*** and is:

(a) for solid fuels, measured in gigajoules per tonne:

  (i) as mentioned in Part 1 or Part 7 of Schedule 1; or

  (ii) estimated by analysis of the fuel in accordance with the standard indicated for that energy content factor in Schedule 2 or an equivalent standard; or

(b) for gaseous fuels, measured in gigajoules per cubic metre:

  (i) as mentioned in Part 2 or Part 7 of Schedule 1; or

  (ii) estimated by analysis under Subdivision 2.3.3.2; or

(c) for gaseous fuels measured in gigajoules — equal to 1; or

(d) for liquid fuels, measured in gigajoules per kilolitre:

  (i) as mentioned in Part 3 or Part 7 of Schedule 1 for stationary energy purposes; or

(ii) as mentioned in Division 4.1 or Part 7 of Schedule 1 for transport energy purposes; or

(iii) estimated by analysis under Subdivision 2.4.3.2; or

(e) for electricity measured in kilowatt hours — equal to 0.0036.

(1A) Despite subsection (1), if:

(a) the kind of energy is one of the following:

(i) solar energy for electricity generation;

(ii) wind energy for electricity generation;

(iii) water energy for electricity generation;

(iv) geothermal energy for electricity generation; and

(b) the energy is consumed from the operation of the facility during the year; and

(c) from that consumption of energy, electricity is produced from the operation of the facility during the year;

then the energy content of the consumed energy is taken to be equal to the energy content of the electricity produced as estimated under Part 6.1.

(2) The amount of electricity consumed from the operation of the facility during the year must be:

(a) evidenced by invoices, contractual arrangements or industry metering records; or

(b) estimated in accordance with industry practice, if such evidence is unavailable.

(3) If, in relation to a year:

(a) a method used by a person requires the EC_i factor to be estimated under this section in relation to a particular fuel type (***i***); and

(b) a way of estimating is chosen for the fuel type as required by this section; and

(c) other methods used by the person for the same fuel type also require the EC_i factor to be estimated under this section;

then the chosen way of estimating, and the amount estimated, must also be applied in using the other methods for the fuel type in relation to that year.

6.5A Reporting

The *National Greenhouse and Energy Reporting Regulations 2008*, Div 4.4 specifies information relating to greenhouse gas emissions, energy production and energy consumption that must be included in a registered corporation's report for a reporting year if the corporation's group meets a threshold in subsection 13 (1) of the Act for that year.

If the operation of a facility of the corporation consumes energy during a reporting year, the corporation's report must include information for the facility identifying separately:

a) the amount and type of energy consumed by means of combustion for:

   (i) producing electricity;

   (ii) producing a chemical product or metal product;

   (iii) transport, other than transport that involves the consumption of international bunker fuel; and

   (iv) a purpose other than a purpose mentioned in subparagraphs (i) to (iii); and

b) the amount of energy consumed by a means other than combustion (if this amount is greater than 20 tonnes of solid fuel, 13 000 cubic metres of gaseous fuel or 15 kiloliters of liquid fuel.)

c) the criteria used by the corporation to estimate the amount of the energy consumed.

d) The methods used to estimate greenhouse gas emissions from the consumption of energy.

If the operation of a facility of the corporation consumes energy in the production of a chemical product containing carbon during a year, the corporation's report for the facility must include information identifying the amount and type of energy consumed in the production of the product.

The consumption of solar, water, wind and geothermal energy for electricity generation should identify the amount of energy of these types subsequently converted into electricity.

Fuels and other energy commodities	Amount of energy consumed	Criteria used by the corporation to estimate the amount of the energy consumed
The amount of energy consumed from fuels is listed in Chapter 2. The amount of energy consumed from energy commodities is listed below.		
Sulphur combusted for energy		
Solar energy for electricity generation		
Wind energy for electricity generation		
Water energy for electricity generation		
Geothermal energy for electricity generation		
Uranium		
Hydrogen		
Electricity purchased from the grid		
Electricity not purchased from the electricity grid		
Energy commodities other than those mentioned above and in the form of steam, compressed air or waste gas acquired either to produce heat or for another purpose		

Chapter 7 Scope 2 emissions

7.1 Outline of Chapter

Chapters 1-5 relate to the estimation of scope 1 emissions.

This chapter concerns Scope 2 emissions which 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.

This Chapter specifies a method of determining scope 2 emissions from the consumption of purchased electricity that has been used by the Greenhouse Challenge Plus for over a decade. The method accommodates electricity measured either in kilowatt hours or gigajoules.

It is intended that the Scope 2 emissions factors will be updated each year.

Scope 2 emissions also arise from electricity acquired from off-grid sources that do not form part of the facility.

These Scope 2 emissions may be estimated using section 7.3 below. Emission factors can be provided by the supplier of the electricity, or if unavailable, the emission factor for NT may be used. NT electricity generation primarily represents a mix of natural gas and diesel generation which is a reasonable match for the fuel mix used in the generation of off-grid electricity generation.

7.2 Method 1 — purchase of electricity from main electricity grid in a State or Territory

(1) The following method must be used for estimating scope 2 emissions released from electricity purchased from the main electricity grid in a State or Territory and consumed from the operation of a facility during a year:

$$Y = Q \times \frac{EF}{1000}$$

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 or Territory in which the consumption occurs as mentioned in the table below.

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.

(4) The ***main electricity grid*** for a State or Territory means:

(a) for Western Australia — the Southwest Interconnected System; and

(b) for each other State or Territory — the electricity grid that provides electricity to the largest percentage of the State's or Territory's population.

7.3 Method 1 — purchase of electricity from other sources

(1) The following method must be used for estimating scope 2 emissions released from electricity:

(a) purchased from a grid other than the main electricity grid in a State or Territory; and

(b) 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 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, either:

(a) provided by the supplier of the electricity; or

(b) if that factor is not available, the emission factor for the Northern Territory 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.

Table 7.2 Indirect (scope 2) emission factors for consumption of purchased electricity from a 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	0.89
80	South Australia	0.77
81	South West Interconnected System in Western Australia	0.84
82	Tasmania	0.23
83	Northern Territory	0.68

Other Scope 2 Emissions

Scope 2 emissions also arise from heating, cooling, or steam acquired from outside the facility.

These Scope 2 emissions may be estimated in consultation with the vendor of the heating, cooling or steam to ensure consistency and completeness with the vendor's estimates of scope 1 emissions for those energy commodities.

Example A

A company has operations in NSW and Queensland. A component of the company's energy use is electricity purchased from the grid. During the year the NSW operations consumed 11,300,000 kWh of electricity, while the Queensland operations consumed 14,600,000 kWh. Emissions are estimated as follows:

$$Y = Q \times EF/1000$$

where:

Y is the scope 2 emissions.

Q is the quantity of electricity purchased from the electricity grid measured in kilowatt hours. **In this case 11,300,000 kWh from NSW and 14,600,000 kWh from QLD.**

EF is the scope 2 emission factor, in either kilograms of CO_2 e emissions per kilowatt hour for the State or Territory in which the consumption occurs as specified in Part 6 of Schedule 1. **In this case it is 0.89 kg CO_2-e/kWh for NSW and 0.91 CO_2-e/kWh for QLD.**

Therefore, to calculate Scope 2 emissions:

For NSW operations

=(11,300,000 x 0.89)/1000

= 10,057 t Scope 2 CO_2-e

For QLD operations

=(14,600,000 x 0.89)/1000

= 12,994 t Scope 2 CO_2-e

Example B

A company uses steam from another facility to provide heat and returns condensate back to the other facility. During the year the company consumed 5,700 gigajoules of energy from the steam. Emissions are estimated as follows:

$$Y = Q \times EF/1000$$

where:

Y is the scope 2 emissions.

Q is the quantity of steam purchased from the other facility. **In this case the quantity of steam purchased is 5,700 GJ.**

EF is the scope 2 emission factor for the steam, in this case measured in kg CO_2-e/GJ. The vendor has provided a scope 2 emission factor for the steam of 400 kg CO_2-e/GJ.

Therefore, to calculate Scope 2 emissions:

Scope 2 emissions

= (5,700 x 400) / 1000

= 2280 t Scope 2 CO_2-e

The scope 2 emission factors are state-based emission factors from on-grid electricity generation calculated systematically from the physical characteristics of the electricity grid. The state-based emission factor calculates an average emission factor for all electricity consumed from the grid in a given state, territory or electricity grid. All emissions attributable to a state territory or grid's electricity consumption are

allocated amongst individual consumers in proportion to their relative level of consumption. In effect, the likelihood of a particular generator supplying a particular consumer is assumed to reflect each generator's relative level of supply to the grid. The reason for this approach is that within an electricity grid it is impossible to physically trace or control the actual physical source of electricity received by each customer.

This approach minimises information requirements for the system and produces factors that are relatively easy to interpret and apply, and which are used to support a range of specific government programs and policies. Consistent adoption of these 'physical' state-based emission factors ensures the emissions generated in each state are fully accounted for by the end-users of the purchased electricity and double counting is avoided.

It is recognised that this approach does not serve all possible policy purposes and that alternative, more data-intensive approaches are possible. Reporters will be able to provide additional data on a voluntary basis on consumption of certain renewable products.

Background to Scope 2 factor estimates

The scope 2 emission factors reflect data that are based on:

- on-grid activity only;
- state-based activity;
- annual financial year averages;
- physical characteristics of the electricity supply and demand.

The estimated electricity emission factors have been aligned with the definitions used in *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard* of the World Resources Institute/World Business Council for Sustainable Development (the GHG Protocol).

The emission factor for scope 2 is defined in terms of energy sent out on the grid rather than energy delivered because this effectively ensures that end users of electricity are allocated only the scope 2 emissions attributable to the electricity they consume and not the scope 2 emissions attributable to electricity lost in transmission and distribution. The latter are allocated to the transmission and distribution network. This follows the GHG Protocol guidance that scope 2 emissions be reported by the organisation owning or controlling the plant or equipment where the electricity is consumed. Companies that own or control transmission and distribution networks report their transmission and distribution loss emissions under scope 2.

The emission factors are calculated as financial year averages based on electricity generation within each state and territory and take into account interstate electricity flows (where they exist) and the emissions attributable to those flows. To reduce volatility scope 2 emission factors are calculated as a three-year moving average.

Scope 2 emissions result from the generation of purchased electricity from each state's electricity grid. The emission factor at generation ($EFG\ scope2^t_i$) is used to calculate scope 2 emissions and is defined for state i and financial year t:

$$EFG\ scope2_i^t = \frac{Combustion\ emissions\ from\ electricity\ consumed\ from\ the\ grid\ in\ state\ i\ (CE_C_i^t)}{Electricity\ sent\ out\ consumed\ from\ the\ grid\ in\ state\ i\ (ESO_C_i^t)}$$

Where

'combustion emissions from electricity consumed from the grid in state i' (CE_C_{ti}) and 'energy sent out consumed from the grid in state i' (ESO_C_{ti}) are defined in terms of the state's electricity grid generation, imports and exports as follows:

$$CE_C_i^t = CE_P_i^t + \sum^{j}\left(\frac{ESO_M_{j,i}^t}{ESO_P_j^t} \times CE_P_j^t\right) - \sum^{k}\left(\frac{ESO_X_{i,k}^t}{ESO_P_i^t} \times CE_P_i^t\right)$$

$$ESO_C_i^t = ESO_P_i^t + \sum^{j} ESO_M_{j,i}^t - \sum^{k} ESO_X_{i,k}^t$$

where

CE_P_{ti} is the total CO_2-e emissions from fuel combustion at generation attributed to the electricity generated/produced for the grid in state i in financial year t

CE_P_{tj} is the total CO_2-e emissions from fuel combustion at generation attributed to the electricity generated for the grid in state j in financial year t

$ESO_M_{tj,i}$ is the imports of energy sent out from state j to state i in financial year t. Imports are calculated from the interregional flows of electricity across the interconnectors published by the National Electricity Market Management Company (NEMMCO)

$ESO_X_{ti,k}$ is the exports of energy sent out from state i to state k in financial year t. Exports are calculated from the inter-regional flows of electricity across the interconnectors published by NEMMCO

ESO_P_{tj} is the total energy sent out on the grid that is generated within state j in financial year t

ESO_P_{ti} is total energy sent out on the grid that is generated within state i in financial year t

The estimated 'Scope 2' emission factors for consumption of purchased electricity use data from Department of Climate Change surveys supplemented with data from the National Electricity Market Management Company, ABARE and the Energy Supply Association of Australia. Emission estimates are taken from the National Greenhouse Accounts. Further detail on the approach to calculating electricity emission estimates is available in the *National Inventory Report 2007*.

Chapter 8 Assessment of uncertainty

Part 8.1 Preliminary

The *GHG Protocol guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty (September 2003) v1.0 (the uncertainty protocol)* is the source document for the methodology of calculating uncertainty under NGERS. It is referred to in this chapter as *the uncertainty protocol.*

This document is produced by the World Resources Institute and the World Business Council on Sustainable Development and is available at http://www.ghgprotocol.org/calculation-tools/all-tools and has detailed information about the calculation of uncertainty in greenhouse gas inventories.

There are a number of different sources of uncertainty identified in the uncertainty protocol – however corporations are only asked to estimate the statistical uncertainty. This type of uncertainty results from natural variations (for example, random human errors in the measurement process and fluctuations in measurement equipment). More information is provided in the uncertainty protocol.

Note that the provision of estimated uncertainty is on a voluntary basis for 2008-09 and 2009-10.

8.1 Outline of Chapter

(1) This Chapter sets out rules about how uncertainty is to be assessed in working out estimates of scope 1 emissions for a source, a facility and a registered corporation.

(2) Part 8.2 sets out general rules for assessing uncertainty of scope 1 emissions estimates.

(3) Part 8.3 sets out how to assess the uncertainty of estimates of scope 1 emissions that have been estimated using method 1.

(4) Part 8.4 sets out how to assess the uncertainty of estimates of scope 1 emissions that have been estimated using method 2, 3 or 4.

(5) Emissions estimates for a source that are calculated using method 1, 2 or 3 are a function of a number of parameters. The uncertainty of the emissions estimates consists of the uncertainty associated with each of these parameters, which may include one or more of the following parameters:

(a) energy content factor;

(b) emissions factor;

(c) activity data.

Note In the case of fuel combustion, activity data refers to the quantity of fuel combusted. In the case of industrial processes, activity data refers to the quantity of product consumed or produced, as appropriate.

(6) Estimates of emissions need only provide for statistical uncertainty.

Note The uncertainty protocol provides information about the assessment of uncertainty.

A definition of statistical uncertainty is provided in the uncertainty protocol.

Part 8.2 General rules for assessing uncertainty

Note that there is a difference in meaning between the common usage of the word 'confidence' and its statistical usage in relation to '95% confidence interval'. In natural science and technical experiments it is often standard practice to estimate uncertainty at the 95% confidence interval. The 'confidence interval' is defined by a probability value (in this case a probability of 95%) and confidence limits on either side of the mean value.

This means that the uncertainty level (the +/- percentages – otherwise known as the confidence limits) is to be calculated so that there is a 95% probability that the true value of the estimate is encompassed by the estimated uncertainty levels (the confidence limits). For example, an emission estimate of 100kt +/- 10% at the 95% confidence interval means that the true value lies between 90kt and 110kt with a probability of 95%.

8.2 Range for emission estimates

Uncertainty must be assessed so that the range for an emissions estimate encompasses the actual amount of the emissions with 95% confidence.

8.3 Uncertainty to be assessed having regard to all facilities

The calculation of uncertainty for a registered corporation should take into account the uncertainty associated with all the sources of emissions reported by the corporation. The uncertainty associated with each emission source is to be aggregated to the "subtotal" of uncertainty at the facility level and the uncertainty associated with each facility if to be aggregated to the "total" of uncertainty at the corporation level.

In the calculation of uncertainty, it is important that the corporation calculates their uncertainty at the same level of disaggregation to which the emission estimate was calculated. For example, if a facility uses multiple types and qualities of a fuel (e.g different types of coals) for which it has data on, and the emission calculation incorporates the data on each different fuel types, then the uncertainty calculation should also be performed at the same level of disaggregation. In other words, the

uncertainty calculation should incorporate uncertainty data on the different fuel types at the same level of detail that was performed in the emission calculation.

(1) Uncertainty of estimates of scope 1 emissions for a registered corporation must be assessed in accordance with the uncertainty protocol, having regard to all of the facilities under the operational control of the corporation.

(2) For corporations that have multiple sources of scope 1 emissions that are estimated using a variety of method 1, 2, 3 or 4, the uncertainty associated with the emissions must be aggregated in accordance with section 8 of the uncertainty protocol.

Part 8.3 How to assess uncertainty when using method 1

8.4 Purpose of Part

This Part sets out how to assess uncertainty of scope 1 emissions if method 1 is used to estimate:

(a) scope 1 emissions for a source; and

(b) scope 1 emissions for a facility; and

(c) scope 1 emissions for a registered corporation.

8.5 General rules about uncertainty estimates for emissions estimates using method 1

(1) The total uncertainty of scope 1 emissions estimates for a source in relation to a registered corporation is to be worked out by aggregating, as applicable, the uncertainty of the emissions factor, the energy content factor and the activity data for the source in accordance with the formula in section 8.11.

Note This is generally referred to as the aggregated uncertainty for the source.

(2) The total uncertainty of scope 1 emissions estimates for a facility is to be worked out by adding the total uncertainty for each source associated with the facility in accordance with the formula in section 8.12.

Note This is generally referred to as the subtotal uncertainty for a facility.

(3) The total uncertainty of scope 1 emissions estimates for a registered corporation is to be worked out by adding the total uncertainty for each facility under the operational control of the corporation in accordance with the formula in section 8.13.

Note This is generally referred to as the total uncertainty for the corporation.

8.6 Assessment of uncertainty for estimates of carbon dioxide emissions from combustion of fuels

(1) In assessing uncertainty of the estimates of carbon dioxide emissions estimated using method 1 for a source that involves the combustion of a fuel, the assessment must include the statistical uncertainty associated with the following parameters:

(a) the energy content factor of the fuel (as specified in column 3 of the following table or as worked out in accordance with item 1, 2 or 3 of section 7 of the uncertainty protocol);

(b) the carbon dioxide emission factor of the fuel (as specified in column 4 of the following table or as worked out in accordance with item 1, 2 or 3 of section 7 of the uncertainty protocol);

(c) the quantity of fuel combusted (as worked out in accordance with subsection (2) or as worked out in accordance with item 1, 2 or 3 of section 7 of the uncertainty protocol).

Item	Fuel combusted	Energy content uncertainty level (%)	Carbon dioxide emission factor uncertainty level (%)
1	Black coal (other than used to produce coke)	28	5
2	Brown coal	50	12
3	Coking coal	12	7
4	Brown coal briquettes	40	11
5	Coke oven coke	9	11
6	Coal tar	50	17
7	Solid fossil fuels other than those mentioned in items 1 to 5	50	15
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	50	26
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	50	26
10	Dry wood	50	NA
11	Green and air-dried wood	50	NA
12	Sulphite lyes	50	NA
13	Bagasse	50	NA
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or energy	50	NA
15	Charcoal	50	NA
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	50	NA
17	Natural gas if distributed in a pipeline	4	4
18	Coal seam methane that is captured for combustion	4	4

Item	Fuel combusted	Energy content uncertainty level (%)	Carbon dioxide emission factor uncertainty level (%)
19	Coal mine waste gas that is captured for combustion	4	4
20	Compressed natural gas that has reverted to standard conditions	4	4
21	Unprocessed natural gas	4	4
22	Ethane	4	10
23	Coke oven gas	50	19
24	Blast furnace gas	50	17
25	Town gas	4	4
26	Liquefied natural gas	7	4
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	50	10
28	Landfill biogas that is captured for combustion (methane only)	50	NA
29	Sludge biogas that is captured for combustion (methane only)	50	NA
30	A biogas that is captured for combustion, other than those mentioned in items 28 and 29 (methane only)	50	NA
31	Petroleum based oils (other than petroleum based oils used as fuel)	11	2
32	Petroleum based greases	11	2
33	Crude oil including crude oil condensates	6	3
34	Other natural gas liquids	7	9
35	Gasoline (other than for use as fuel in an aircraft)	3	4
36	Gasoline for use as fuel in an aircraft	3	4
37	Kerosene (other than for use as fuel in an aircraft)	3	2
38	Kerosene for use as fuel in an aircraft	3	3
39	Heating oil	5	2
40	Diesel oil	2	2
41	Fuel oil	2	2
42	Liquefied aromatic hydrocarbons	5	2
43	Solvents if mineral turpentine or white spirits	18	2
44	Liquid petroleum gas	8	3
45	Naphtha	5	5
46	Petroleum coke	19	17
47	Refinery gas and liquids	19	18
48	Refinery coke	19	17

Item	Fuel combusted	Energy content uncertainty level (%)	Carbon dioxide emission factor uncertainty level (%)
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	18	2
50	Biodiesel	50	NA
51	Ethanol for use as a fuel in an internal combustion engine	50	NA
52	Biofuels other than those mentioned in items 50 and 51	50	NA

(2) In the table in subsection (1), ***NA*** means not applicable.

(3) For a fuel type specified in column 2 of an item of the following table:

(a) column 3 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion A in Chapter 2; and

(b) column 4 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AA in Chapter 2; and

(c) column 5 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AAA in Chapter 2; and

(d) column 6 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion BBB in Chapter 2.

Note Division 2.2.5 sets out the relevant criteria for solid fuels; Division 2.3.6 sets out the relevant criteria for gaseous fuels; and Division 2.4.6 sets out the relevant criteria for liquid fuels.

		Uncertainty levels for quantities of fuel combusted (%)			
		Criterion used for estimation of quantity of fuel combusted			
Item	Fuel type	A	AA	AAA	BBB
1	Solid fuel	2.5	2.5	1.5	7.5
2	Liquid fuel	1.5	1.5	1.5	7.5
3	Gaseous fuel	1.5	1.5	1.5	7.5

8.7 Assessment of uncertainty for estimates of methane and nitrous oxide emissions from combustion of fuels

(1) In assessing uncertainty of the estimates of methane and nitrous oxide emissions estimated using method 1 for a source that involves the combustion of a fuel specified in column 2 of an item in the table in subsection 8.6 (1):

(a) the uncertainty level of the energy content factor is as specified in column 3 for the item; and

(b) the uncertainty level of the emissions factor is:

(i) 50%; or

(ii) as worked out in accordance with section 7 of the uncertainty protocol.

(2) In assessing uncertainty of the estimates of methane and nitrous oxide emissions estimated using method 1 for a source that involves the combustion of a fuel type specified in column 2 of an item in the table in subsection 8.6 (2):

(a) column 3 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion A in Chapter 2; and

(b) column 4 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AA in Chapter 2; and

(c) column 5 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AAA in Chapter 2; and

(d) column 6 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion BBB in Chapter 2.

Note Division 2.2.5 sets out the relevant criteria for solid fuels; Division 2.3.6 sets out the relevant criteria for gaseous fuels; and Division 2.4.6 sets out the relevant criteria for liquid fuels.

8.8 Assessment of uncertainty for estimates of fugitive emissions

Note that the uncertainty levels in this section are the aggregate uncertainty levels for the source and may be used by substituting directly into the aggregation equations for facilities and the corporation in sections 8.12 and 8.13 as appropriate. Default individual parameter uncertainties have not been provided for fugitive emissions that are calculated under method 1 and hence the parameter aggregation equation in section 8.11 is not applicable when these defaults are used.

The aggregated uncertainty of the estimates of fugitive emissions estimated using method 1 for a source mentioned in column 2 of an item of the following table is:

(a) as specified in column 3 for the item; or

(b) as worked out in accordance with the uncertainty protocol.

Item	Sources	Aggregated uncertainty level (%)
1	Underground mines	50
2	Open cut mines	50
3	Decommissioned underground mines	50
4	Oil or gas exploration	50
5	Crude oil production	50
6	Crude oil transport	50
7	Crude oil refining	50
8	Natural gas production or processing (other than emissions that are vented or flared)	50
9	Natural gas transmission	50

Item	Sources	Aggregated uncertainty level (%)
10	Natural gas distribution	50
11	Natural gas production or processing — flaring	25

8.9 Assessment of uncertainty for estimates of emissions from industrial process sources

(1) In assessing uncertainty of the estimates of emissions estimated using method 1 for the industrial process sources mentioned in column 2 of an item of the following table, the assessment must include the uncertainty level for the emission factor and activity data associated with the source:

(a) as specified:

(i) for the emission factor — in column 3 for the item; and

(ii) for the activity data — in column 4 for the item; or

(b) as worked out in accordance with the uncertainty protocol.

Item	Industrial process sources	Emission factor uncertainty level (%)	Activity data uncertainty (%)
1	Cement clinker production	6	1.5
2	Lime production	6	1.5
3	Soda ash use	5	1.5
4	Use of carbonates for the production of a product other than cement clinker, lime or soda ash	5	1.5
5	Nitric acid production	40	1.5
6	Adipic acid production	10	1.5

(2) In assessing uncertainty of the estimates of emissions estimated using method 1 for industrial process sources mentioned in column 2 of an item of the following table, column 3 for the item sets out the aggregated uncertainty level associated with the source.

For aluminium production the uncertainty for estimates of emissions may be assessed using the information provided in Chapter 4 of the *2006 IPCC Guidelines for National Greenhouse Gas Inventories (Volume 3)*.

Item	Industrial process sources	Aggregated uncertainty level (%)
1	Emissions of hydrofluorocarbons and sulphur hexafluoride gas	30

Note that the above uncertainty level is the aggregate uncertainty level for the source (Emissions of hydrofluorocarbons and sulphur hexafluoride gas) and may be used by substituting directly into the aggregation equations for facilities and the corporation in sections 8.12 and 8.13 as appropriate. Default individual parameter uncertainties

have not been provided for this emission source calculated under method 1 and hence the parameter aggregation equation in section 8.11 is not applicable when the above default is used.

(3)The uncertainty of estimates of emissions for industrial process sources that are not mentioned in subsections (1) or (2) must be assessed:

(a) if the industrial process source involves the combustion of fuel — in accordance with:

(i) for carbon dioxide emissions — section 8.6; and

(ii) for methane and nitrous oxide emissions — section 8.7; and

(b) if the industrial process source does not involve the combustion of fuel — in accordance with the uncertainty protocol.

8.10 Assessment of uncertainty for estimates of emissions from waste

Note that the uncertainty levels in this section are the aggregate uncertainty levels for the source and may be used by substituting directly into the aggregation equations for facilities and the corporation in sections 8.12 and 8.13 as appropriate. Default individual parameter uncertainties have not been provided for waste sector emissions calculated under method 1 and hence the parameter aggregation equation in section 8.11 is not applicable when these defaults are used.

In assessing uncertainty of the estimates of emissions from waste estimated using method 1 for the activities mentioned in column 2 of an item of the following table, the assessment must include the aggregated uncertainty level:

(a) as specified in column 3 for the item; or

(b) as worked out in accordance with the uncertainty protocol.

Item	Activities	Aggregated uncertainty level (%)
1	Solid waste disposal on land	35
2	Wastewater handling (industrial)	65
3	Wastewater handling (domestic or commercial)	40
4	Waste incineration	40

8.11 Assessing uncertainty of emissions estimates for a source by aggregating parameter uncertainties

The technique used in this chapter for aggregating the uncertainty is known as first order error propagation. Further information and guidance is given in the uncertainty protocol and its reference documents. There are four key assumptions that are made

when this technique is used and should be considered when applying these formulas which are:

1. The error in each parameter is normally distributed
2. There are no biases in the estimator function, (i.e. the estimated value is the mean value)
3. The estimated parameters are uncorrelated
4. Individual uncertainties in each parameter must be less than 60% of the mean

In most cases it will be reasonable to assume that the above conditions are satisfied and that any uncertainty calculation will be reasonable.

(1) For subsection 8.5 (1) and subject to subsections (2) and (3), in assessing uncertainty of the estimates of scope 1 emissions that are estimated using method 1 for a source, the aggregated uncertainty for emissions from the source is to be worked out in accordance with the following formula:

$$D = \pm\sqrt{A^2 + B^2 + C^2}$$

where:

D is the aggregated percentage uncertainty for the emission source.

A is the uncertainty associated with the emission factor for the source expressed as a percentage.

B is the uncertainty associated with the energy content factor for the source expressed as a percentage.

C is the uncertainty associated with the activity data for the source expressed as a percentage.

(2) If an assessment of uncertainty of emissions for the source does not require the use of emissions factor uncertainty, energy content factor uncertainty or activity data uncertainty, then A, B or C, as appropriate, in the formula in subsection (1) is taken to be zero.

Example

If energy content factor uncertainty is not required for an industrial process source, then B would be taken to be zero in the formula in subsection (1) when assessing the aggregated uncertainty for the source.

(3) Subsection (1) does not apply to:

(a) estimates of fugitive emissions that are assessed by using the aggregated uncertainty level in column 3 of the table in section 8.8; or

(b) estimates of emissions from industrial processes that are assessed by using the aggregated uncertainty level in column 3 of the table in subsection 8.9 (2); or

(c) estimates of emissions from waste activities that are assessed by using the aggregated uncertainty level in column 3 of the table in section 8.10.

8.12 Assessing uncertainty of emissions estimates for a facility

For subsection 8.5 (2), in assessing uncertainty of estimates of scope 1 emissions for a facility that are estimated using method 1, the following formula must be used to aggregate the uncerstainty of emissions estimates for all the sources associated with the facility:

$$U_{subtotal} = \frac{\pm\sqrt{(D_1 \times E_1)^2 + (D_2 \times E_2)^2 + \ldots + (D_n \times E_n)^2}}{E_1 + E_2 + \ldots + E_n}$$

where:

$\boldsymbol{U_{subtotal}}$ is the percentage uncertainty for the subtotal of emissions for the facility.

$\boldsymbol{D_1 \rightarrow D_n}$ are the percentage uncertainties associated with each emission estimate ($\boldsymbol{E_1 \rightarrow E_n}$) for the source.

$\boldsymbol{E_1 \rightarrow E_n}$ are the estimated emissions from each source associated with the facility measured in CO_2-e tonnes.

8.13 Assessing uncertainty of emissions estimates for a registered corporation

For subsection 8.5 (3), in assessing uncertainty of estimates of scope 1 emissions for a registered corporation that are estimated using method 1, the following formula must be used to aggregate the uncertainty of emissions estimates for all the facilities under the operational control of the corporation:

$$U_{total} = \frac{\pm\sqrt{(D_1 \times E_1)^2 + (D_2 \times E_2)^2 + \ldots + (D_n \times E_n)^2}}{E_1 + E_2 + \ldots + E_n}$$

where:

$\boldsymbol{U_{total}}$ is the percentage uncertainty for the total emissions for the registered corporation.

$\boldsymbol{D_1 \rightarrow D_n}$ are the percentage uncertainties associated with each emission estimate ($\boldsymbol{E_1 \rightarrow E_n}$) for the facility.

$\boldsymbol{E_1 \rightarrow E_n}$ are the estimated emissions from each facility under the operational control of the corporation measured in CO_2-e tonnes.

Example

A corporation has two facilities, each of which has two sources of emissions. The first facility combusts diesel oil and black coal, while the second facility combusts natural gas and gasoline. The calculation of the carbon dioxide equivalent emissions using method 1 and the uncertainty of this (method 1) emission estimate for the corporation are shown in the table below.

For facility 1, an emission source is the combustion of diesel oil. The emissions for this source are estimated by method 1 to be 2,671.1 CO_2-e tonnes under section 2.41 as shown in the table. Since method 1 has been used to calculate the emissions, the default uncertainty levels from section 8.6 for the parameters used in the emissions calculation are applicable in calculating the uncertainty, which are 1.5% for quantity of fuel combusted (measured in kL), 2% for the energy content factor (measured in GJ/kL), and 2% for the emission factor (kg CO_2-e/GJ).

The aggregated uncertainty for this method 1 emission estimate (combustion of diesel oil) is calculated using the equation in section 8.11 as follows:

$$\sqrt{1.5\%^2 + 2\%^2 + 2\%^2} = 3.2\%$$

Therefore, the aggregate uncertainty for this source is +/- 3.2%. Similar calculations are performed for the uncertainty of the emissions estimate for the second source (combustion of black coal) for facility 1, to yield an uncertainty of 28.6%.

As shown in the table, the carbon dioxide emissions for the second source in facility 1 are estimated under method 1 to be 11,907.0 tonnes CO2e which makes a subtotal of carbon dioxide emissions of 14,578.2 CO_2-e tonnes for facility 1. Then the subtotal uncertainty for facility 1 is calculated using the formula in section 8.12 as shown below:

$$\frac{\sqrt{(3.2\% \times 2{,}671.1)^2 + (28.6\% \times 11{,}907.0)^2}}{14{,}578.2} = 23.3\%$$

Therefore, the subtotal uncertainty of the carbon dioxide emissions for facility 1 is +/- 23.3%. Similar calculations are performed for facility 2, and the results are indicated in the table below, with the carbon dioxide emissions estimate being 24,952.9 CO_2-e tonnes with an uncertainty of +/- 4.5%.

For calculating the total uncertainty for the corporation, use the formula in 8.13, as shown below:

$$\frac{\sqrt{(23.3\% \times 14{,}578.2)^2 + (4.5\% \times 24{,}952.9)^2}}{39{,}531.1} = 9.1\%$$

Similar calculations are then performed for Methane and Nitrous Oxide using the default uncertainties from section 8.7. The total uncertainty for CO_2-e is then calculated and shown in the table below. Therefore the total uncertainty of the carbon dioxide equivalent emissions estimated under method 1 for the corporation is +/- 9.0/%. With the total emissions estimate under method 1 being 39,660.7 kg CO_2-e.

Emissions / Uncertainty	Activity data	Energy Content Factor	Emission Factor	Emission
Emission Data Source	As measured - Chapter 2	Schedule 1	Schedule 1	Calculated under Chapter 2
Emission Calculation Units	kL, t, m3	GJ/kL, GJ/t, GJ/m3	kg CO_2-e/GJ	CO_2e t

Facility 1				
Combustion of Diesel Oil	*1,000*	38.6	69.2	2,671
Uncertainty level	1.5%	2.0%	2.0%	3.2%
Source of Uncertainty Assessment	Section 8.6	Section 8.6	Section 8.6	Section 8.11
Combustion of Black Coal	*5,000*	27	88.2	11,907
Uncertainty level	2.5%	28.0%	5.0%	28.6%
Source of Uncertainty Assessment	Section 8.6	Section 8.6	Section 8.6	Section 8.11
Facility 1 Subtotal				**14,578**
Uncertainty level				23.3%
Source of Uncertainty Assessment				Section 8.12

Facility 2				
Combustion of Natural Gas	*9,000,000*	0.0393	51.2	18,109
Uncertainty level	1.5%	4.0%	4.0%	5.9%
Source of Uncertainty Assessment	Section 8.6	Section 8.6	Section 8.6	Section 8.11
Combustion of Gasoline	*3,000*	34.2	66.7	6,843
Uncertainty level	1.5%	3.0%	4.0%	5.2%
Source of Uncertainty Assessment	Section 8.6	Section 8.6	Section 8.6	Section 8.11
Facility 2 Subtotal				**24,953**
Uncertainty level				4.5%
Source of Uncertainty Assessment				Section 8.12

Corporation Total - CO_2 emissions	**39,531**
Uncertainty level	9.1%
Source of Uncertainty Assessment	Section 8.13

Corporation Total CH_4 and N_2O emissions - kg CO_2-e	**130**
Uncertainty level	22.1%
Source of Uncertainty Assessment - Similar to CO_2 Calculations	

Corporation Total CO_2-e emissions	**39,661**
Uncertainty level	9.0%
Source of Uncertainty Assessment	Section 8.13

Part 8.4 How to assess uncertainty levels when using methods 2, 3 or 4

8.14 Purpose of Part

This Part sets out rules that apply in the assessment of uncertainty of scope 1 emissions from the operation of a facility that are estimated using method 2, 3 or 4.

8.15 Rules for assessment of uncertainty using method 2, 3 or 4

(1) Subject to this section, the uncertainty of scope 1 emissions estimates that are estimated using method 2, 3 or 4 must be assessed in accordance with the uncertainty protocol.

(2) Item 4 of Part 7 of the uncertainty protocol must not be used when emissions are estimated using method 2, 3 or 4.

(3) Estimates need only provide for statistical uncertainties in accordance with the uncertainty protocol.

The technique described in the *GHG uncertainty protocol* to be applied when methods 2, 3 and 4 are used to estimate emissions is similar to the technique outlined for the calculation of uncertainty for method 1. The key difference is that the parameter uncertainties should be estimated directly rather than taken from the default tables in sections 8.6 to 8.10. Techniques for estimating these parameters are given in section 7 of the uncertainty protocol. Also, further guidance and discussion on calculation of uncertainty is given in uncertainty protocol.

Generally, the uncertainties estimated under the higher order methods 2, 3 and 4 are likely to be lower than those calculated under method 1, indicating that the emission estimate using the higher order methods is more accurate than that calculated under method 1. The main reason for this is that in method 1 default energy content factors are used and there is significant uncertainty around these defaults, particularly for solid fuels such as coal (note that electricity generators are required to use methods 2 or higher for emissions estimates). Higher order methods of analysis require direct analysis of the fuel giving a much more accurate estimation of the carbon content of fuels and hence the emissions.

Example

Estimates of emissions and uncertainty for the same corporation (combusting the same estimated fuel quantities) are now given using method 2. The parameters used in the method 2 emissions calculation are different to that of method 1 and the source of parameter uncertainty is estimated by the corporation (rather than taken from tables). Note that calculations for aggregating uncertainties are similar to those for method 1 and guidance is given in the uncertainty protocol.

Note that guidance on estimating the parameter uncertainties is given in section 7 of the GHG protocol, (although item 4 in the list of available methods in section 7 is not to be used).

Facility 1								
Combustion of Diesel Oil	Q - kL	% carbon	Fuel density kg/kL	EC	OF	Constant	EF	Emission (tonnes)
	1,000	*85.2*	*850*	38.6	0.99	3.664	68.1	2,627
Uncertainty	1.5%	1.5%	1.0%	NA	0.0%	NA	1.8%	2.3%
Source of Uncertainty	a	b	c	d	e	f	g	g
Combustion of Black Coal	Q - t	% carbon		EC	OF	Constant	EF	Emission
	5,000	*62.2*	NA	27	0.98	3.664	82.7	11,167
Uncertainty	2.5%	3.0%	NA	NA	0.0%	NA	3.0%	3.9%
Source of Uncertainty	a	b		d	e	f	g	g
Facility 1 Subtotal								**13,794**
Uncertainty								3.2%
Source of Uncertainty								h

Facility 2								
Combustion of Natural Gas	Q - m3	Gas Composition	Fuel density kg/m3	EC	OF	Constant	EF	Emission
	9,000,000	NA	*0.74*	0.0393	0.995	2.743	51.4	18,178
Uncertainty	1.5%	3.0%	1.0%	NA	0.0%	NA	3.2%	3.5%
Source of Uncertainty	a	i	c	d	e	f	g	G
Combustion of Gasoline	Q - kL	% carbon	Fuel density kg/kL	EC	OF	Constant	EF	Emission
	3,000	*85.2*	*720*	34.2	0.99	3.664	65.1	6,676
Uncertainty	1.5%	2.0%	1.0%	NA	0.0%	NA	2.2%	2.7%
Source of Uncertainty	a	b	c	d	e	f	g	G
Facility 2 Subtotal								**24,854**
Uncertainty								2.7%
Source of Uncertainty								H

Corporation Total - CO_2 emissions	**38,648**
Uncertainty	2.1%
Source of Uncertainty	H

Corporation Total CH_4 and N20 emissions - kg CO_2-e (using method 1)	**130**
Uncertainty level	22.1%
Source of Uncertainty Assessment - Similar to CO_2 Calculations for method 1	

Corporation Total CO_2-e emissions	**38,778**
Uncertainty level	2.0%
Source of Uncertainty Assessment	H

Notes:

a Uncertainty potentially assessed on fuel measurement instrument precision. Fuel use from stockpiles, for example, may generate larger uncertainties which may need to be considered.

b Sampling and analysis uncertainty, either through instrument precision or other statistical method

c Uncertainty associated with fuel density from sampling and analysis

d Uncertainty associated with energy content not relevant to method 2 since energy content factor falls out in calculation of emissions

e Uncertainty associated with the oxidation factor assumed to be zero in these cases though may be incorporated in an uncertainty calculation where considered significant

f Uncertainty associated with these molecular mass constants is not statistical uncertainty as defined by the uncertainty protocol and hence is not incorporated

g This uncertainty is aggregated using the method in section 7 of the uncertainty protocol

h This uncertainty is aggregated using the method in section 8 of the uncertainty protocol

i Sampling and analysis uncertainty of gas composition (assumed to be 100% methane in the emission calculation)

Appendix A: 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 that has reverted to standard conditions	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
35	Gasoline (other than for use as fuel in an aircraft)	0.629

Item	Fuel type	Carbon content factor (tC/kL of fuel unless otherwise specified)
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
56	Ethylene if used as a petrochemical feedstock	0.856

Item	Fuel type	Carbon content factor (tC/t fuel unless otherwise specified)
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	Styrene	0.923

Notes on Carbon Content Factors

1. Energy value: Source – $ABARE_1$ (washed steaming). CO_2 emission factor: Source - National Inventory Report 2006, Department of Climate Change (forthcoming).

2. Energy value: Source - AGEIS database, Department of Climate Change (based on facility reports). CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports).

3. Energy value: Source – $ABARE_1$ (washed coking). CO_2 emission factor: Source - National Inventory Report 2006, Department of Climate Change (forthcoming).

4. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports).

5. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

6. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming) (coal tar).

7. See (4)

8. Energy value: Source – GHD Review of Sectoral Models, Internal report to the AGO, 2006. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

9. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

10. Energy value: Source: $ABARE_1$ (dry wood).

11. Energy value: Source: $ABARE_1$ (green wood).

12. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. .

13. Energy value: Source: $ABARE_1$.

14. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.

15. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.

16. See (14)

17. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

18. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

19. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

20. See (17)

21. See (17)

22. Energy value: Source: $ABARE_2$ (average). CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

23. Energy value: Source: $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

24. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.90.

25. Energy value: Source – $ABARE_2$ (synthetic natural gas). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

26. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

27. See (17)

28. Energy value: Source – $ABARE_1$.

29. Energy value: Source – $ABARE_1$.

30. See (28)

31. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (lubricants and greases).

32. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (lubricants and greases).

33. Energy value: Source – $ABARE_2$ (weighted average). CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

34. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

35. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

36. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

37. Energy value: Source – $ABARE_2$ (power kerosene). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

38. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

39. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming). .

40. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

41. Energy value: Source – $ABARE_2$ (low sulfur). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming). Derived using conversion factor of 0.95.

42. Energy value: Source – $ABARE_2$. Given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (assumed same as solvents).

43. Energy value: Source – $ABARE_2$. CO_2 emission factor: National Inventory Report 2006, Department of Climate Change (forthcoming).

44. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming). .

45. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

46. Energy value: Source – IPCC 2006. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

47. Energy value: Source – $ABARE_1$ (refinery fuel). CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

48. See (46)

49. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

50. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (assumed same as solvents).

51. Energy value: Source – $ABARE_2$. Based on IPCC 2006, given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (set same as solvents).

52. Energy value: Source – Derived from US Department of Energy. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

53. Energy value: Source – $ABARE_2$. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

54. See (53).

55. Assumed to be 100% carbon

56. Carbon content obtained through stoichiometric estimation

57. Carbon content assumed the same as ethylene

58. Carbon content obtained through stoichiometric estimation

59. Carbon content obtained through stoichiometric estimation

60. Carbon content obtained through stoichiometric estimation

61. Carbon content obtained through stoichiometric estimation

62. Carbon content obtained through stoichiometric estimation

Notes:

ABARE$_1$ 2007 *Fuel and Electricity Survey – Fuel Codes,* Australian Bureau of Agricultural and Resource Economics *www.abareconomics.com/publications_html/surveys/surveys/surveys.html,* Commonwealth of Australia, Canberra.

ABARE$_2$ 2007 *Energy in Australia 2006,* produced for Department of Industry, Tourism and Resources, pages 77-79, Commonwealth of Australia ,Canberra.

Department of Climate Change (2008), *National Inventory Report 2006*, Commonwealth of Australia, Canberra

Intergovernmental Report on Climate Change (2006), *2006 IPCC Guidelines for National Greenhouse Gas Inventories;* Japan.

Appendix B: Definitions and interpretation

Definitions

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 2009.

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.

blast furnace gas means the gas that occurs as a result of operating a blast furnace.

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

brown coal means brown coal that has a gross calorific value of:

(a) less than 17 435 kilojoules per kilogram (4 165 kilocalories per kilogram); and

(b) greater than 31% volatile matter on a dry mineral free base.

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.

chemical product means ammonia, nitric acid, titanium dioxide, soda ash or synthetic rutile.

chemical product containing carbon means 1 of the following:

(a) polyethylene;

(b) polypropylene;

(c) BR or SBR rubber;

(d) styrene;

(e) carbon black.

CO_2-e means carbon dioxide equivalence.

coal tar means the tar that results from the destructive distillation of bituminous coal or the low temperature carbonization of brown coal.

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

cogeneration process means a process that combines the generation of heat and power to produce electricity and another product within 1 integrated production process.

coke oven coke means the solid product obtained from the carbonisation of coal (principally coking coal) at a high temperature and includes coke breeze and foundry coke.

coke oven gas means the gas that is a by-product in the production of coke or iron and steel.

compressed natural gas means natural gas that is:

(a) used for vehicles that are modified to use such gas; and

(b) stored in high pressure fuel cylinders prior to being used in those vehicles.

consumption of energy, in relation to a facility, means the use or disposal of energy from the operation of the facility including own-use and losses in extraction, production and transmission.

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 means a condensate recovered from natural gas that is mixed with the crude oil.

crude oil transport means the transportation of marketable crude oil to heavy oil upgraders and refineries by means that include the following:

(a) pipelines;

(b) marine tankers;

(c) tank trucks;

(d) rail cars.

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 means wood that:

(a) has a moisture content of 20% or less if the moisture content is calculated on a wet basis; and

(b) is combusted to produce heat or electricity.

efficiency method has the meaning given by 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.

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.

facility specific emission factor, for a source for a facility, is the parameter in the equation that determines the rate of emissions for the facility estimated in accordance with method 2, 3 or 4 for the source in the Determination.

feedstock means the use of a fuel as a raw material in production.

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 other than a substance mentioned in items 58 to 66.

fuel oil has the meaning given in section 3 of the *Excise Tariff Act 1921*.

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.

gaseous fuel means a fuel mentioned in column 2 of items 17 to 30 of Schedule 1 to the Regulations

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 means wood that:

(a) has a moisture content of more than 20% if the moisture content is calculated on a wet basis; and

(b) is combusted to produce heat or electricity.

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.

hydrofluorocarbons means any of the hydrofluorocarbons listed in the table in regulation 2.04 of the Regulations.

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, means emissions of greenhouse gas from the operation of a facility are if, in a reporting year:

(a) an individual source of emission from the operation of the facility is less than:

(i) 0.5% of the total amount of greenhouse gases emitted from the operation of the facility; and

(ii) a carbon dioxide equivalence of 3 kilotonnes for a year; and

(b) the total amount of all of the individual sources of emission mentioned in paragraph (a) is less than the lesser of:

(i) 2% of the total amount of greenhouse gases emitted from the operation of the facility; or

(ii) a carbon dioxide equivalence of 12 kilotonnes; and

(c) information about the sources of these emissions from the operation of the facility is not required to be collected or provided under any other Commonwealth, State or Territory law; and

(d) the corporation provides a statement that measurement of emissions of greenhouse gas from these sources using another method or criteria in the Determination would cause the corporation significant hardship or expense.

independent expert, in relation to an operator of a landfill, means a person who:

(a) is independent of the operator of the landfill; and

(b) has relevant expertise in estimating or monitoring landfill surface gas.

integrated metal works has the meaning given by subsection 4.64 (2).

international bunker fuel means a fuel that powers an engine of a ship or aircraft and that is supplied for use:

(a) in an aircraft for a flight from a place within Australia to a place outside of Australia; or

(b) in a ship on a voyage from a place within Australia to a place outside of Australia;

whether or not part of the flight or voyage involves a journey between places in Australia.

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.

liquid fuel means a fuel mentioned in column 2 of items 31 to 54 of Schedule 1 to the Regulations

landfill gas means the gas derived from the fermentation of biomass and solid waste in landfills and combusted to produce heat or electricity.

liquid aromatic hydrocarbons means hydrocarbons that consist principally of benzene, toluene and xylene. Equivalent to item 10.25 of the *Excise Tariff Act 1921*.

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.

main electricity grid has the meaning given by subsection 7.2 (4).

marketable crude oil includes:

(a) conventional crude oil; and

(b) heavy crude oil; and

(c) synthetic crude oil; and

(d) bitumen.

metal product means aluminium, ferroalloys, iron, steel or any other metal.

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 means non-biodegradable materials from sources such as domestic households, industry (including the service industries) and hospitals.

N/A means not available.

National Greenhouse Accounts means the set of national greenhouse gas inventories, including the National Inventory Report, 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 means liquefied hydrocarbons recovered from natural gas in separation facilities or processing plants and includes ethane, propane, butane (including normal and iso-butane) and pentane (including iso-pentane and pentanes plus).

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 greases means:

(a) petroleum based greases and their synthetic equivalents (Equivalent to item 15.3 of the *Excise Tariff Act 1921)*; or

(b) oils (including lubricants, fluids and greases) derived from petroleum and their synthetic equivalents, if recycled for use as greases (Equivalent to item 15.4 of the *Excise Tariff Act 1921)*.

petroleum based oils means any of the following:

(a) oils (including lubricants or fluids but not greases) derived from petroleum and their synthetic equivalents (Equivalent to item 15.1 of the *Excise Tariff Act 1921)*;

(b) oils (including lubricants, fluids and greases) derived from petroleum and their synthetic equivalents, if recycled for use as oils (Equivalent to item 15.2 of the *Excise Tariff Act 1921)*.

petroleum coke means a black solid by-product of carbonising petroleum derived feedstock, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking.

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.

production of energy, in relation to a facility, means 1 of the following:

(a) the extraction or capture of energy from natural sources for final consumption by or from the operation of the facility or for use other than in the operation of the facility;

(b) the manufacture of energy by the conversion of energy from 1 form to another form for final consumption by or from the operation of the facility or for use other than in the operation of the facility.

raw sugar has the meaning given by Chapter 17, Section IV, Schedule 3 of the *Customs Tariff Act 1995*

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

refinery coke means the coke that is deposited on the catalyst during petroleum refining and that is not recoverable.

refinery gases and liquids has means non condensable gases or liquids consisting mainly of hydrogen, methane, ethane and olefins, that are obtained during the distillation of crude oil or treatment of oil products in oil refineries.

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 means releases of greenhouse gases as a result of an activity, or series of activities (including ancillary activities) that constitute the facility.

scope 2 emissions means releases of greenhouse gases as a result of activities that generate electricity, heating, cooling or steam that are consumed by the facility but do not form part of the facility.

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.

solid fuel means a fuel mentioned in column 2 of items 1 to 16 of Schedule 1 to the Regulations

source has the meaning given by section 1.10.

standard includes a protocol, technical specification or USEPA method.

standard conditions means, as measured on a dry gas basis:

(a) air pressure of 101.325 kilopascals; and

(b) air temperature of 15.0 degrees Celsius; and

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

sulphite lyes has means a fuel that is an alkaline spent liquor resulting from the production of sulphate or soda pulp during the manufacture of paper.

synthetic gas generating activities for emissions of sulphur hexafluoride, are any activities of a facility that emit sulphur hexafluoride. For emissions of hydrofluorocarbons synthetic gas generating activities 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).

technical guidelines means the document published by the Department and known as the *National Greenhouse Energy and Reporting (Measurement) Technical Guidelines 2009*.

uncertainty protocol means the publication known as the *GHG Uncertainty protocol guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty* (September 2003) v1.0 issued by the World Resources Institute and the World Business Council on Sustainable Development.

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.

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 means waxes that:

(a) are aliphatic hydrocarbons; and

(b) have a crystalline structure; and

(c) are colourless, odourless and translucent; and

(d) have a melting point above 45 degrees Celsius.

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.

Appendix C: Global Warming Potentials, Units and Conversions

Global Warming Potentials

Greenhouse Gas	Chemical Formula	Global Warming Potential (GWP)
Carbon dioxide	CO_2	1
Methane	CH_4	21
Nitrous oxide	N_2O	310
Sulphur hexafluoride	SF_6	23 900
HFC-23	CHF_3	11 700
HFC-32	CH_2F_2	650
HFC-41	CH_3F	150
HFC-43-10mee	$C_5H_2F_{10}$	1 300
HFC-125	C_2HF_5	2 800
HFC-134	$C_2H_2F_4$ (CHF_2CHF_2)	1 000
HFC-134a	$C_2H_2F_4$ (CH_2FCF_3)	1 300
HFC-143	$C_2H_3F_3$ (CHF_2CH_2F)	300
HFC-143a	$C_2H_3F_3$ (CF_3CH_3)	3 800
HFC-152a	$C_2H_4F_2$ (CH_3CHF_2)	140
HFC-227ea	C_3HF_7	2 900
HFC-236fa	$C_3H_2F_6$	6 300
HFC-245ca	$C_3H_3F_5$	560
Perfluoromethane (tetrafluoromethane)	CF_4	6 500
Perfluoroethane (hexafluoroethane)	C_2F_6	9 200
Perfluoropropane	C_3F_8	7 000
Perfluorobutane	C_4F_{10}	7 000
Perfluorocyclobutane	c-C_4F_8	8 700
Perfluoropentane	C_5F_{12}	7 500
Perfluorohexane	C_6F_{14}	7 400

Note 1 Global Warming Potential (also known as GWP) is defined in the Glossary published by the UNFCCC as an index representing the combined effect of the differing times greenhouse gases remain in the atmosphere and their relative effectiveness in absorbing outgoing infrared radiation.
Note 2 The Global Warming Potential figures in the above table are the figures published by the Intergovernmental Panel on Climate Change in *Climate Change 1995: The Science of Climate Change* (Cambridge, UK: Cambridge University Press, 1996). These GWPs are currently used by Governments for all international reporting under the UNFCCC.

Metric prefixes

Prefix	Abbreviation	Symbol
Peta (million billion [thousand trillion])	10^{15} (10^6x10^9)	P
Tera (thousand billion [trillion])	10^{12} (10^3x10^9)	T
Giga (billion)	10^9	G
Mega (million)	10^6	M
kilo (thousand)	10^3	k
hecto	10^2	h
deca	10^1	da
– (e.g. gram)	10^0	g
deci	10^{-1}	d
centi	10^{-2}	c
milli	10^{-3}	m
micro	10^{-6}	µ
nano	10^{-9}	n
pico	10^{-12}	p

Unit equivalences

1015 grams (Petagram)	Gigatonne (Gt)
1012 grams (Teragram)	Megatonne (Mt)
10^9 grams (Gigagram)	kilotonnes (kt) (10^3 tonnes)
10^6 grams (million grams)	1 tonne
kg/GJ (10^3g/10^9J)	Gg/PJ (10^9g/10^{15}J)
Mg/PJ (10^6g/1015J)	g/GJ 10^0g/10^9J)

For example: 423,000 Gg is equivalent to 423,000 kt and to 423 Mt

Energy and power units

Unit of energy: Joule
Unit of power (rate of energy usage): Watt

Energy conversion factors

Conversion factors	
1 Watt	= 1 joule per second
3600 Watt-seconds	= 1 Watt-hour (3600 seconds in one hour)
1 Watt-hour	= 3600 joules
1000 Watt-hours	= 1 Kilowatt hour (kWh)
1 kWh	= 3.6×10^{6} joules = 3.6 mega joules
1 kWh	= 3.6×10^{-3} GJ
1 GJ	= 278 kWh
1 PJ	= 278×10^{6} kWh = 278 GWh

(A) For conversion from first unit to second unit:	(B) Multiply quantity in first unit by conversion factor:	(C) To calculate quantity in second unit:
kWh to J	kWh x 3.6×10^{6}	Joules
J to kWh	J x $1/3.6 \times 10^{-6}$	kWh
kWh to MJ	kWh x 3.6	MJ
MJ to kWh	MJ x 0.278	kWh
kWh to GJ	kWh x 3.6×10^{-3}	GJ
GJ to kWh	GJ x 278	kWh
kWh to PJ	kWh x 3.6×10^{-9}	PJ
PJ to kWh	PJ x 278×10^{6}	kWh

Municipal solid waste volume to weight conversion factors

Material type	Volume to weight
Paper	0.09
Textiles	0.14
Wood	0.15
Garden	0.24
Food	0.50
Co-mingled	0.12

Note: Volume to weight conversions is an inexact science and conversion factors change if materials are compacted.

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