National Greenhouse and Energy Reporting (Measurement) Determination 2008

made under subsection 10(3) of the

National Greenhouse and Energy Reporting Act 2007

Draft Compilation of Planned Amendments, 2021

Includes related amendments to the ***National Greenhouse and Energy Reporting Regulations 2008***

Prepared by the Department of Industry, Science, Energy and Resources, Canberra

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Division 1.1.2—Definitions and interpretation

1.8 Definitions

Note that some definitions, such as natural gas gathering and boosting, natural gas gathering and boosting pipeline, natural gas gathering and boosting station, natural gas processing station were inserted in 2020 and are included here for ease of reference. Some definitions are related to the National Greenhouse and Energy Reporting Regulations 2008 (the Regulations) and these amendments are included immediately below.

Repeal:

crude oil condensates has the meaning given by the Regulations.

technical guidelines means the document published by the Department and known as the *National Greenhouse Energy and Reporting (Measurement) Technical Guidelines 2009*.

Insert into section 1.8 (or replace existing definitions):

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

…

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

(i) crude oil, plant condensate and other natural gas liquids;

captured for enhanced oil recovery: a greenhouse gas is captured for enhanced oil recovery if it is captured and transferred to the holder of an enhanced oil recovery authority for injection into a geological formation, such as a natural reservoir, to further oil or gas production activities and is not captured for permanent storage.

city gate means a distribution hub where gas is reduced in pressure before it enters the lower pressure, smaller diameter, distribution pipeline network.

CO_2 stimulation means using carbon dioxide as a fluid in well stimulation treatment which enhances oil and gas production or recovery by increasing the permeability of the formation.

crude oil has the meaning given by the Regulations.

enhanced oil recovery authority means a licence, lease or approval by or under a law of the Commonwealth, State or Territory which authorises the injection of one or more greenhouse gases into one or more geological formations, such as a natural reservoirs, to further oil or gas production activities.

fugitive emissions means greenhouse gas emissions that are:

(a) released in connection with, or as a consequence of, the extraction, processing, storage or delivery of fossil fuel; and

(b) not released from the combustion of fuel for the production of useable heat or electricity.

Leak Detection and Repair Program or ***LDAR program*** means a system of procedures used at a facility to monitor, locate and repair leaking components in order to minimize emissions.

leaker, in relation to a component subject to an LDAR program, means:

(a) if optical gas imaging is used, a leaker is detected at a sensitivity of 60 grams per hour in accordance with paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America; and

(b) if the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America is used, a leaker is detected if 10,000 parts per million or greater is measured consistent with that method.

liquefied natural gas station means the plant and equipment used in the natural gas liquefaction, storage and transfer of liquefied natural gas, and includes:

(a) all onshore or offshore equipment that receives natural gas, liquefies and stores liquefied natural gas, and transfers the liquefied natural gas to a transportation system; and

(b) equipment that receives imported or transported liquefied natural gas, stores liquefied natural gas, re-gasifies liquefied natural gas, and delivers re-gasified natural gas to a natural gas transmission or distribution system.

natural gas distribution means the transport of pipeline natural gas over a combination of natural gas distribution pipelines from a city gate to customer delivery points.

natural gas distribution pipelines mean pipelines for the conveyance of pipeline natural gas that:

(a) are identified as a distribution pipeline in an access arrangement applicable to the pipeline; or

(b) meet both of the following:

(i) have a maximum design pressure of 1,050 kPa or less; and

(ii) are not natural gas gathering and boosting pipelines.

natural gas gathering and boosting means the activity to collect unprocessed natural gas or coal seam methane from gas wellheads and to compress, dehydrate, sweeten, or transport the gas through natural gas gathering and boosting pipelines to a natural gas processing station, a natural gas transmission pipeline or natural gas distribution pipeline.

natural gas gathering and boosting pipeline means a pipeline for the conveyance of gas that:

(a) contains unprocessed natural gas or coal seam methane; and

(b) pertains to the activity of natural gas gathering and boosting.

Note: Such pipelines can operate at high or low pressures

natural gas gathering and boosting station means one or more pieces of plant and equipment used in natural gas gathering and boosting at a single location that operates as a unit in the natural gas gathering and boosting activity. The plant and equipment may include any of the following:

(a) compressors;
(b) generators;
(c) dehydrators;
(d) storage vessels;
(e) acid gas removal units;
(f) engines;
(g) boilers;
(h) heaters;
(i) flares;
(j) separation and processing equipment;
(k) associated storage or measurement vessels;
(l) equipment on, or associated with, an enhanced oil recovery well pad using CO_2 or gas injection.

Note: The single location that operates as a unit will generally be known as a facility, station or node for operational purposes. It is not expected that stations will be defined differently for operational purposes and emissions accounting purposes.

natural gas liquefaction, storage and transfer means the activity to collect and liquefy natural gas and to store and transfer liquefied natural gas to a transportation system.

natural gas processing means one or both of the following activities:
(a) the separation of natural gas liquids or non-methane gases from unprocessed natural gas or coal seam methane;
(b) the separation of natural gas liquids into one or more component mixtures.

Note: The separation includes one or more of the following: forced extraction of natural gas liquids, sulphur and carbon dioxide removal, fractionation of natural gas liquids, or the capture of CO_2 separated from natural gas streams.

natural gas processing station means the plant and equipment used in natural gas processing at a single location, and includes:
(a) liquids recovery plant and equipment where the separation of natural gas liquids or non-methane gases from unprocessed natural gas or coal seam methane occurs; and
(b) liquids recovery plant and equipment where the separation of natural gas liquids into one or more component mixtures occur; and
(c) gas separation trains where the removal of acidic gases from unprocessed natural gas or coal seam methane occurs.

Note: The separation includes one or more of the following: forced extraction of natural gas liquids, sulphur and carbon dioxide removal, fractionation of natural gas liquids, or the capture of CO_2 separated from unprocessed natural gas and coal seam methane streams.

natural gas storage means the activity to store unprocessed natural gas, coal seam methane or natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas).

natural gas storage station means the plant and equipment used in natural gas storage, and includes:
(a) subsurface storage, such as depleted gas or oil reservoirs that store gas; and

(b) the equipment to undertake natural gas underground storage processes and operations (including compression, dehydration and flow measurement, but excluding natural gas transmission pipelines); and
(c) all the wellheads connected to the compression units located at the station that inject and recover natural gas into and from the underground reservoirs.

natural gas transmission means transmission of natural gas or plant condensate through one or more natural gas transmission pipelines from a natural gas processing station or a natural gas gathering and boosting network to any of the following:
(a) a natural gas distribution network;
(b) another natural gas processing station;
(c) a liquefied natural gas station;
(d) a large industrial facility, such as a power station.

natural gas transmission pipeline means a pipeline for the conveyance of pipeline natural gas or plant condensate that:
(a) is licensed as a transmission pipeline under a Commonwealth, State or Territory law; and
(b) has a maximum design pressure exceeding 1,050 kPa; and
(c) is not a natural gas distribution pipeline or a natural gas gathering and boosting pipeline.

oil or gas exploration and development means the activity to explore for oil and gas resources and test, appraise, drill, develop and complete wells for oil and gas resources and includes the following actions:
(a) oil well drilling;
(b) gas well drilling;
(c) drill stem testing;
(e) well appraisals;
(f) development drilling;
(g) well completions;
(h) well workovers associated with the actions in the paragraphs above.

offshore natural gas production means the activity to produce, extract, recover, lift, stabilise, separate or treat unprocessed natural gas, condensate or coal seam methane on offshore submerged lands, including well workovers.

offshore platform includes:
(a) any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses plant and equipment to do either or both of the following:
    (i) extract unprocessed natural gas and condensate from the ocean or lake floor;
    (ii) transfers such unprocessed natural gas and condensate to storage, transport vessels, or onshore; and
(b) secondary platform structures connected to the platform structure via walkways, and

(c) storage tanks associated with the platform structure; and
(d) floating production and storage offloading equipment; and
(e) submerged wellhead production structures.

offshore platform (shallow water) means an offshore platform standing in less than 200 metres of water.

offshore platform (deep water) means an offshore platform standing in at least 200 metres of water.

onshore natural gas production means the activity to produce, extract, recover, lift, stabilise, separate or treat unprocessed natural gas, condensate or coal seam methane on land, including well workovers.

onshore natural gas production wellhead means the gas wellhead.

plant condensate has the meaning given by the Regulations**.**

pipeline natural gas means natural gas that is suitable for market consumption.

produced water means the water that is either:
(a) pumped from coal seams or unprocessed gas reservoirs during onshore or offshore natural gas production or natural gas gathering and boosting; or
(b) pumped from wells during crude oil production or oil and gas exploration and development.

well workover means activities performed to restore or increase production which can include any or all of the following processes:
(a) well venting;
(b) tubing maintenance;
(c) air clean out;
(d) hydraulic fracturing and recovery;
(e) well unloading.

Consequential amendments to the Measurement Determination will also remove the phrase 'that is captured for combustion' from sections 2.24, 2.26 and 8.6, Part 2 of Schedule 1 and Part 2 of Schedule 3. This ensures consistency with changes to Schedule 1 of the Regulations set out below. Other references will remain unchanged.

The related definitional changes to the Regulations are as follows:

1 Regulation 1.03 (definition of *captured for combustion*)

Repeal the definition.

2 Regulation 1.03 (at the end of the definition of *coal mine waste gas*)

Add:

; and (c) has not been injected into a natural gas transmission pipeline or natural gas distribution pipeline.

3 Regulation 1.03 (paragraph (e) of the definition of *coal seam methane*)

Omit "supply pipeline", substitute "transmission pipeline or natural gas distribution pipeline".

4 Regulation 1.03

Insert:

crude oil includes field condensates.

5 Regulation 1.03 (definition of *crude oil condensates*)

Repeal the definition.

6 Regulation 1.03

Insert:

field condensate means a mixture of lower molecular weight hydrocarbons that are recovered from an oil or gas field at surface separation facilities at or near the field.

liquefied natural gas means natural gas that is sourced from a process or vessel where the gas is in a liquid state because of pressure and low temperatures.

Note: Natural gas becomes a liquid when chilled to around -161 °C.

liquefied petroleum gas means:

(a) liquid propane; or
(b) liquid butane; or
(c) a liquid mixture of propane and butane; or
(d) a liquid mixture of propane and other hydrocarbons that consists mainly of propane; or
(e) a liquid mixture of butane and other hydrocarbons that consists mainly of butane; or
(f) a liquid mixture of propane, butane and other hydrocarbons that consists mainly of propane and butane.

7 Regulation 1.03 (definition of *liquid petroleum fuel*)

Repeal the definition.

8 Regulation 1.03 (definition of *LNG* or *liquefied natural gas*)

Repeal the definition.

9 Regulation 1.03 (definition of *LPG* or *liquefied petroleum gas*)

Repeal the definition.

10 Regulation 1.03 (paragraph (c) of the definition of *natural gas*)

Omit "methane; and", substitute "methane.".

11 Regulation 1.03 (paragraph (d) of the definition of *natural gas*)

Repeal the paragraph.

12 Regulation 1.03 (definition of *natural gas liquids*)

Repeal the definition, substitute:

natural gas liquids means liquefied hydrocarbons recovered from natural gas in separation facilities or processing plants, including any of the following:

(a) ethane;

(b) propane;

(c) butane (including normal and iso-butane);

(d) pentane (including iso-pentane and pentanes plus).

13 Regulation 1.03 (definition of *natural gas supply pipeline*)

Repeal the definition.

14 Regulation 1.03

Insert:

natural gas transmitted or distributed in a pipeline means natural gas that has been injected into a natural gas transmission pipeline or natural gas distribution pipeline.

plant condensate means liquid separated in a processing plant from a gaseous hydrocarbon stream by condensation, other than liquefied petroleum gas.

15 Regulation 1.03 (paragraph (c) of the definition of *refinery gases and liquids*)

Omit "26", substitute "25, 27A".

16 Regulation 1.03 (paragraph (d) of the definition of *unprocessed natural gas*)

Omit "supply pipeline", substitute "transmission pipeline or natural gas distribution pipeline".

17 Schedule 1A

Repeal the Schedule.

18 Schedule 1 (table item 17)

After "Natural gas", insert "transmitted or".

19 Schedule 1 (table items 18 and 19)

Omit "that is captured for combustion".

20 Schedule 1 (table item 26)

Repeal the item.

21 Schedule 1 (table item 27)

Omit "26", substitute "25".

22 Schedule 1 (after table item 27)

Insert:

Liquefied natural gas		
27A	Liquefied natural gas	Secondary

23 Schedule 1 (table, subheading before table item 28)

Omit “*captured for combustion*”.

24 Schedule 1 (table items 28 and 29)

Omit “that is captured for combustion”.

25 Schedule 1 (table item 30)

Omit “that is captured for combustion, other than those”, substitute “that is not”.

26 Schedule 1 (table items 33 and 34)

Repeal the items, substitute:

33	Crude oil	Nomination required
34	Plant condensate and other natural gas liquids not covered by another item in this table	Nomination required

National Greenhouse and Energy Reporting (Measurement) Determination 2008

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 January 2020.

1.10 Meaning of *source*

(1) A thing mentioned in the column headed 'Source of emissions' of the following table is a ***source***.

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 and development (other than flaring)
2E		Crude oil production
2F		Crude oil transport
2G		Crude oil refining
2H		Onshore natural gas production (other than emissions that are vented or flared)
2HA		Offshore natural gas production (other than emissions that are vented or flared)
2HB		Natural gas gathering and boosting (other than emissions that are vented or flared)
2HC		Produced water from natural gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting (other than emissions that are vented or flared)
2HD		Natural gas processing (other than emissions that are vented or flared)

Item	Category of source	Source of emissions
2I		Natural gas transmission (other than flaring)
2IA		Natural gas storage (other than emissions that are vented or flared)
2J		Natural gas distribution (other than flaring)
2JA		Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)
2K		Oil or gas exploration and development—flaring
2KA		Onshore natural gas production—flaring
2KB		Offshore natural gas production—flaring
2KC		Natural gas gathering and boosting—flaring
2KD		Natural gas processing—flaring
2KE		Natural gas transmission—flaring
2KF		Natural gas storage—flaring
2KG		Natural gas distribution—flaring
2KH		Natural gas liquefaction, storage and transfer—flaring
2L		Natural gas production—venting
2LA		Natural gas gathering and boosting—venting
2LB		Natural gas processing—venting
2LC		Natural gas storage—venting
2LD		Natural gas liquefaction, storage and transfer—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 or carbon anode
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
3P		Sodium cyanide production

Item	Category of source	Source of emissions
4	Waste	
4A		Solid waste disposal on land
4AA		Biological treatment of solid waste
4B		Wastewater handling (industrial)
4C		Wastewater handling (domestic or commercial)
4D		Waste incineration

(2) The extent of the source is as provided for in this Determination.

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.

(3) Method 1 must not be used for estimating emissions of carbon dioxide for the main fuel combusted from the operation of the facility if:

(a) the principal activity of the facility is electricity generation (ANZSIC industry classification and code 2611); and

(b) the generating unit:

(i) has the capacity to produce 30 megawatts or more of electricity; and

(ii) generates more than 50 000 megawatt hours of electricity in a reporting year.

(4) Method 1 must not be used for estimating emissions of methane for the combustion of coal seam methane or unprocessed natural gas if:

(a) the principal activity of the facility is oil and gas extraction (ANZSIC industry classification and code 07); and

(b) the coal seam methane or unprocessed natural gas is not combusted for electricity generation.

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

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

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

(2) In applying method 1 under section 2.20, the emission factor $\boldsymbol{EF_{ijoxec}}$ is to be:

(a) 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; or

(b) estimated based on the manufacturer's specification for the specific equipment type under relevant operational conditions, including the effect of any supplementary equipment technologies that modify methane emitted to the atmosphere.

Part 2.4—Emissions released from the combustion of liquid fuels

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

Subdivision 2.4.3.2—Sampling and analysis

2.45 Standards for analysing samples of liquid fuels

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

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

(b) for carbon analysis—column 4 for that item; and

(c) density analysis—column 5 for that item.

Item	Fuel	Energy Content	Carbon	Density
	…			
3	Crude oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005) ASTM D 5002 – 99 (2005)
4	Plant condensates and other natural gas liquids not covered by another item in this table	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)

Division 2.4.4—Method 3—emissions of carbon dioxide from liquid fuels other than petroleum based oils or greases

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

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

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

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

item	Liquid Fuel	Standard
	…	

item	Liquid Fuel	Standard
3	Crude oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
4	Plant condensates and other natural gas liquids not covered by another item in this table	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005) ASTM D1265 – 05

Part 3.3—Oil and natural gas—fugitive emissions

Division 3.3.1—Preliminary

3.41 Outline of Part

(1) This Part provides for fugitive emissions from the following:

(a) oil or gas exploration and development (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) onshore natural gas production, other than emissions that are vented or flared (see Division 3.3.6A);

(f) offshore natural gas production, other than emissions that are vented or flared (see Division 3.3.6B);

(g) natural gas gathering and boosting, other than emissions that are vented or flared (see Division 3.3.6C);

(h) produced water from natural gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting, other than emissions that are vented or flared (see Division 3.3.6D);

(i) natural gas processing, other than emissions that are vented or flared (see Division 3.3.6E);

(j) natural gas transmission, other than emissions that are flared (see Division 3.3.7);

(k) natural gas storage, other than emissions that are vented or flared (see Division 3.3.7A);

(l) natural gas liquefaction, storage and transfer, other than emissions that are vented or flared (see Division 3.3.7B);

(m) natural gas distribution, other than emissions that are flared (see Division 3.3.8);

(n) natural gas production (emissions that are vented or flared) (see Division 3.3.9A).

(o) natural gas gathering and boosting (emissions that are vented or flared) (see Division 3.3.9B).

(p) natural gas processing (emissions that are vented or flared) (see Division 3.3.9C).

(q) natural gas transmission (emissions that are flared) (see Division 3.3.9D).

(r) natural gas storage (emissions that are vented or flared) (see Division 3.3.9E)

(s) liquefied natural gas storage or transfer (emissions that are vented or flared) (see Division 3.3.9F).

(t) natural gas distribution (emissions that are flared) (see Division 3.3.9G).

(2) The activities at a facility should be classified in accordance with the relevant definitions to apply the calculations in this Part to comprehensively cover the emissions from the facility, but not count the emissions more than once.

3.41A Interpretation

Terms relating to the oil and gas industry in this Part are to be interpreted:

(a) consistently with their accepted meaning in the oil and gas industry; and

(b) where the term is relevant to methods in the API Compendium—taking into account the meaning and scope of the term in that compendium.

Division 3.3.2—Oil or gas exploration and development

Subdivision 3.3.2.1—Preliminary

3.42 Application

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

(a) oil well drilling; and
(b) gas well drilling; and
(c) oil well completions; and
(d) gas well completions; and
(e) well workovers; and
(f) well blowouts; and
(g) cold process vents.

Subdivision 3.3.2.2—Oil or gas exploration and development (emissions that are flared)

3.43 Available methods

(1) Subject to section 1.18, for estimating emissions released by oil or gas flaring during the year from the operation of a facility that is constituted by oil or gas exploration and development:

(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 2A under section 3.45A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:
(i) method 1 under section 3.44;
(ii) method 2A under section 3.45A.

Note: There is no method 4 under paragraph (a) and no method 2, 3 or 4 under paragraph (b) or (c).

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

3.44 Method 1—oil or gas exploration and development

(1) Method 1 is:

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

where:

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

Q_i is the quantity of fuel type (*i*) flared in the oil or gas exploration and development during the year measured in tonnes.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

EF_{ij} is the emission factor for gas type (*j*) measured in tonnes of CO_2-e emissions per tonne of the fuel type (*i*) flared.

(2) For EF_{ij} in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor, for gas type (*j*), for each fuel type (*i*) specified in column 2 of that item.

Item	**Fuel type (*i*)**	**Emission factor for gas type (*j*) (tonnes CO_2-e/tonnes of fuel flared)**		
		CO_2	**CH_4**	**N_2O**
1	Gas	2.80	0.933	0.026
2	Crude oil and liquids	3.20	0.009	0.06

3.45 Method 2—oil or gas exploration and development (flared carbon dioxide emissions)

Combustion of gaseous fuels (flared) emissions

(1) For subparagraph 3.43(1)(a)(ii), method 2 for combustion of gaseous fuels is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

E_{iCO_2} is the fugitive emissions of CO_2 from fuel type (*i*) flared in oil or gas exploration and development during the year, measured in CO_2-e tonnes.

Q_h is the total quantity of hydrocarbons (*h*) within the fuel type (*i*) in oil or gas exploration and development during the year, measured in tonnes in accordance with Division 2.3.3.

EF_h is the emission factor for the total hydrocarbons (*h*) within the fuel type (*i*) in oil or gas exploration and development during the year, measured in CO_2-e tonnes per tonne of the fuel type (*i*) flared, estimated in accordance with Division 2.3.3.

OF_i is 0.98, which is the destruction efficiency of fuel type (*i*) flared.

QCO_2 is the quantity of CO_2 within fuel type (*i*) in oil or gas exploration and development during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

Combustion of liquid fuels (flared) emissions

(2) For subparagraph 3.43(1)(a)(ii), method 2 for combustion of liquid fuels is the same as method 1 under section 3.44, but the carbon dioxide emissions factor $\boldsymbol{EF_{ij}}$ must be determined in accordance with method 2 in Division 2.4.3.

3.45A Method 2A—oil or gas exploration and development (flared methane or nitrous oxide emissions)

For subparagraphs 3.43(1)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

$\boldsymbol{EF_{hij}}$ is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration and development during the year, mentioned for the fuel type in the table in subsection 3.44(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

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

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration and development during the year, measured in tonnes in accordance with Division 2.3.3 for gaseous fuels or Division 2.4.3 for liquid fuels.

3.46 Method 3—oil or gas exploration and development

Combustion of gaseous fuels (flared) emissions

(1) For subparagraph 3.43(1)(a)(iii), method 3 for the combustion of gaseous fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.3.4.

Combustion of liquid fuels (flared) emissions

(2) For subparagraph 3.43(1)(a)(iii), method 3 for the combustion of liquid fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.4.4.

Subdivision 3.3.2.3—Oil or gas exploration and development—fugitive emissions from system upsets, accidents and deliberate releases

3.46A Available methods

(1) Subject to section 1.18, the methods mentioned in subsections (2) and (3) must be used for estimating fugitive emissions that result from system upsets, accidents and deliberate releases during a reporting year from the operation of a facility that is constituted by oil or gas exploration and development.

(2) To estimate emissions for methane and carbon dioxide that result from deliberate releases from process vents, systems upsets and accidents at a facility during a year, for each oil or gas exploration and development activity one of the following methods must be used:

(a) method 1 under:

(i) section 3.46AB (natural gas well completions); and

(ii) section 3.56B (emissions from system upsets, accidents and deliberate releases from process vents); and

(iii) section 3.85P (well workovers); and

(iv) section 3.85B (cold process vents);

(b) method 4 under:

(i) for emissions of methane and carbon dioxide from natural gas well completions activities, well workovers, cold process vents and well blowouts—section 3.46B; or

(ii) for emissions and activities not mentioned in subparagraph (i)—Part 1.3.

(3) For estimating incidental emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, another method may be used that is consistent with the principles mentioned in section 1.13.

Note: There is no method 2 or 3 for this Subdivision.

Subdivision 3.3.2.3.1—Fugitive emissions that result from deliberate releases from process vents, system upsets and accidents–well completions

3.46AB Method 1—vented emissions from natural gas well completions

(1) Method 1 is:

$E_{ij} = \Sigma_k \; Q_{ik} \times EF_{ijk} \times S_{ij} / SD_{ij}$

where:

E_{ij} is the fugitive emissions of gas type (***j***), being methane or carbon dioxide, vented from the natural gas exploration and development during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, 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 natural gas exploration and development.

Q_{ik} is the total of the number of well completion events for equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas exploration and development.

EF_{ijk} is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per well completion event using equipment type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas exploration and development.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed natural gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed natural gas (***i***), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(2) For ***EF_{ijk}*** mentioned in subsection (1), column 3 of an item in the following table specifies the emission factor for methane for an equipment of type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide for an equipment of type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	**CO_2**	
1	Well completion without hydraulic fracturing	5.5	1.1×10^{-2}	tonnes CO_2-e per well completion event
2	Well completion with hydraulic fracturing and venting (no flaring)	1031	4.2	tonnes CO_2-e per well completion event
3	Well completion with hydraulic fracturing with capture (no flaring)	90.8	0.37	tonnes CO_2-e per well completion event
4	Well completion with hydraulic fracturing and flaring	136.6	0.56	tonnes CO_2-e per well completion event

3.46B Method 4—vented emissions from natural gas well completions, well workovers, cold process vents and well blowouts

Method 4 is, for natural gas well completion activities, well workovers, cold process vents and well blowouts, as described in section 5.7.2 or 5.7.1 of the API Compendium for production related non-routine emissions.

Division 3.3.3—Crude oil production

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) an 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 reinjection systems; and

(g) activities at upgrading plants and associated gas reinjection 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 leak emissions of methane

3.48 Available methods

(1) Subject to section 1.18, for estimating fugitive emissions of methane, other than fugitive emissions of methane specified in subsection (1A), 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;

(c) method 3 under section 3.51.

Note: There is no method 4 for this Division.

(1A) For subsection (1), the following fugitive emissions of methane are specified:

(a) fugitive emissions from oil or gas flaring;

(b) fugitive emissions that result from system upsets, accidents or deliberate releases from process vents.

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

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

(1) Method 1 is:

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

where:

$\boldsymbol{E_{ij}}$ 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 total 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.

$\boldsymbol{EF_{ijk}}$ 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.

$\boldsymbol{Q_i}$ is the total quantity of crude oil (***i***) measured in tonnes that passes through the crude oil production.

$\boldsymbol{EF_{(l)\ ij}}$ is 1.6×10^{-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 $\boldsymbol{EF_{ijk}}$ 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	1.12×10^{-6}
2	Fixed roof tank	5.60×10^{-6}
3	Floating tank	4.27×10^{-6}

(3) For $\boldsymbol{EF_{(l)\ ij}}$ in subsection (1), general leaks in the crude oil production comprise the emissions (other than vent emissions) from equipment listed in sections 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production.

3.50 Method 2—crude oil production (non-flared) emissions of methane

(1) Method 2 is:

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

where:

$\boldsymbol{E_{ij}}$ 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 total 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 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment type is used in the crude oil production.

$\boldsymbol{Q_{ik}}$ 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 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 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 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium as determined under subsection (2), 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 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 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.

3.51 Method 3—crude oil production (non-flared) emissions of methane

(1) Method 3 is:

$$E_{ij} = \sum_k (EF_{ijk} \times T_{ik} \times N_k)$$

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 total emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil production.

$\boldsymbol{EF_{ijk}}$ is the emission factor of methane (***j***) measured in tonnes of CO_2-e per component-hour that passes through each component type (***k***) listed in section 6.1.3 of the API Compendium as determined under subsection (2), if the component is used in the crude oil production.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of the components of each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil production, measured in hours per year.

$\boldsymbol{N_k}$ is the total number of each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil production, measured in components.

(2) For EF_{ijk}, the emission factors for methane (*j*), as crude oil passes through a component type (*k*), are:

(a) column 3 of an item in the following table, which specifies the emission factor for a component of type (*k*) specified in column 2 of that item:

Item	Component type (k)	Emission factor for gas type (j) (tonnes CO_2-e/component-hour)
		CH_4
1	Valves – heavy crude production	3.64×10^{-7}
2	Valves – light crude production	3.70×10^{-5}
3	Connectors – heavy crude production	2.23×10^{-7}
4	Connectors – light crude production	4.59×10^{-6}
5	Flanges – heavy crude production	6.13×10^{-7}
6	Flanges – light crude production	2.15×10^{-6}
7	Open-ended lines – heavy crude production	4.34×10^{-6}
8	Open-ended lines – light crude production	3.39×10^{-5}
9	Pump Seals – light crude production	8.90×10^{-6}
10	Others – heavy crude production	1.96×10^{-6}
11	Others – light crude production	2.10×10^{-4}

Note: API Publication 4615 defines light crude as oil with an API gravity of 20 or more, and heavy crude as oil with an API gravity of less than 20.

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

Subdivision 3.3.3.3—Crude oil production (flared)—fugitive emissions of carbon dioxide, methane and nitrous oxide

3.52 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 3.53;

(ii) method 2 under section 3.54;

(iii) method 3 under section 3.55; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.53;

(ii) method 2A under section 3.54A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.53;

(ii) method 2A under section 3.54A.

Note: There is no method 4 under paragraph (a) and no method 2, 3 or 4 under paragraph (b) or (c).

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

3.53 Method 1—crude oil production (flared) emissions

(1) For subparagraph 3.52(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.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

$\boldsymbol{EF_{ij}}$ 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	Gas	2.80	0.933	0.026
2	Crude oil and liquids	3.20	0.009	0.06

3.54 Method 2—crude oil production

Combustion of gaseous fuels (flared) emissions of carbon dioxide

(1) For subparagraph 3.52(1)(a)(ii), method 2 for combustion of gaseous fuels is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

$\boldsymbol{E_{iCO_2}}$ is the fugitive emissions of CO_2 from fuel type (***i***) flared in crude oil production during the year, measured in CO_2-e tonnes.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in tonnes in accordance with Division 2.3.3.

$\boldsymbol{EF_h}$ is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with method 2 in Division 2.3.3.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{QCO_2}$ is the quantity of CO_2 within the fuel type (***i***) in crude oil production during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

Combustion of liquid fuels (flared) emissions of carbon dioxide

(2) For subparagraph 3.51(1)(a)(ii), method 2 for combustion of liquid fuels is the same as method 1, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 2 in Division 2.4.3.

3.54A Method 2A—crude oil production (flared methane or nitrous oxide emissions)

For subparagraphs 3.52(1)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

$\boldsymbol{EF_{hij}}$ is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, mentioned for the fuel type in the table in subsection 3.53(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from crude oil production during the year, measured in CO_2-e tonnes.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in tonnes in accordance with Division 2.3.3 for gaseous fuels or Division 2.4.3 for liquid fuels.

3.55 Method 3—crude oil production

Combustion of gaseous fuels (flared) emissions of carbon dioxide

(1) For subparagraph 3.52(1)(a)(iii), method 3 for the combustion of gaseous fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.3.4.

Combustion of liquid fuels (flared) emissions of carbon dioxide

(2) For subparagraph 3.52(1)(a)(iii), method 3 for the combustion of liquid fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.4.4.

Subdivision 3.3.3.4—Crude oil production (non-flared)—fugitive vent emissions of methane and carbon dioxide

3.56A Available methods

(1) Subject to section 1.18, the methods mentioned in subsections (2) and (3) must be used for estimating fugitive emissions that result from system upsets, accidents and deliberate releases from process vents during a year from the operation of a facility that is constituted by crude oil production.

(2) To estimate emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, one of the following methods must be used:
- (a) method 1 under section 3.56B;
- (b) method 4 under Part 1.3.

(3) For estimating incidental emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, another method may be used that is consistent with the principles mentioned in section 1.13.

Note: There is no method 2 or 3 for this Subdivision.

Note: Methods to estimate vented emissions from condensate storage tanks are available at section 3.85D.

3.56B Method 1—emissions from system upsets, accidents and deliberate releases from process vents

(1) Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3

Item	Emission process	API Compendium section
3	Storage tanks - vented emissions	Section 5.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—production related non-routine emissions	Section 5.7.1 and 5.7.2

(2) However, emissions from well workovers may use method 1 under section 3.85P (as if that method referred to crude oil production instead of natural gas production).

Division 3.3.4—Crude oil transport

3.57 Application

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

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.

3.59 Method 1—crude oil transport

Method 1 is:

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

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil transport during the year measured in CO_2-e tonnes.

Q_i is the quantity of crude oil (***i***) measured in tonnes and transported during the year.

EF_{ij} is the emission factor for gas type (***j***), being methane, which is 9.74×10^{-4} tonnes CO_2-e per tonnes of crude oil transported during the year.

3.60 Method 2—fugitive emissions from crude oil transport

(1) Method 2 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions of gas type (***j***), being methane, from the crude oil transport during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane, 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.

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.

EF_{ijk} is the emission factor of gas type (***j***), being methane, 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 as determined under subsection (2), if the equipment is used in the crude oil transport.

(2) For ***EF_{ijk},*** the emission factors for gas type (***j***), being methane, as crude oil passes through equipment type (***k***), are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

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

Division 3.3.5—Crude oil refining

3.62 Application

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

3.63 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 3.64;
   (b) method 2 under section 3.65;
   (c) method 3 under section 3.66.

Note: There is no method 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 3.67;
   (b) method 4 under section 3.68.

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 3.69;
      (ii) method 2 under section 3.70;
      (iii) method 3 under section 3.71; and
   (b) if estimating emissions of methane released—one of the following methods must be used:
      (i) method 1 under section 3.69;
      (ii) method 2A under section 3.70A; and
   (c) if estimating emissions of nitrous oxide released—one of the following methods must be used:
      (i) method 1 under section 3.69;
      (ii) method 2A under section 3.70A.

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 3.69

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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

Subdivision 3.3.5.1—Fugitive emissions from crude oil refining and from storage tanks for crude oil

3.64 Method 1—crude oil refining and storage tanks for crude oil

Method 1 is:

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

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or carbon dioxide, 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 gas type (***j***), being methane or carbon dioxide, 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 gas type (***j***), being methane or carbon dioxide, being 9.47×10^{-4} tonnes CO_2-e per tonne of crude oil refined and 1.73×10^{-4} tonnes CO_2-e per tonne of crude oil stored in tanks.

3.65 Method 2—crude oil refining and storage tanks for crude oil

(1) Method 2 is:

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

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane, from the crude oil refining and from storage tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane, 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 as determined under subsection (2), 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 (***i***) 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 gas type (***j***), being methane, 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 refining and in the storage tanks.

(2) For $\boldsymbol{EF_{ijk}}$, the emission factors for gas type (***j***), being methane, 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.

3.66 Method 3—crude oil refining and storage tanks for crude oil

(1) Method 3 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane, from the crude oil refining and from storage tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component type is used in the crude oil refining and from storage tanks.

$\boldsymbol{Q_{ik}}$ is the total of the quantities of crude oil (***i***) that pass through each component type (***k***), or the number of components of each component type (***k***), listed in section 6.1.3 of the API Compendium , if the component is used in the crude oil refining and from storage tanks, measured in tonnes.

$\boldsymbol{EF_{ijk}}$ is the emission factor of gas type (***j***), being methane, measured in tonnes of CO_2-e per tonne of crude oil that passes through each component type (***k***) listed in section 6.1.3 of the API Compendium as determined under subsection (2), if the component is used in the crude oil refining and from storage tanks.

(2) For $\boldsymbol{EF_{ijk}}$, the emission factors for gas type (***j***), being methane or carbon dioxide, as crude oil passes through a component type (***k***), are:

(a) as listed in section 6.1.3 of the API Compendium, for the component type; or

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

Subdivision 3.3.5.2—Fugitive emissions from deliberate releases from process vents, system upsets and accidents

3.67 Method 1—fugitive emissions from deliberate releases from process vents, system upsets and accidents

Method 1 is:

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

where:

E_i is the fugitive emissions 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.

3.68 Method 4—deliberate releases from process vents, system upsets and accidents

(1) Method 4 is:

(a) is as set out in Part 1.3; or

(b) uses the process calculation approach in section 5.2 of the API Compendium.

(2) For paragraph (1)(b), all carbon monoxide is taken to fully oxidise to carbon dioxide and must be included in the calculation.

Subdivision 3.3.5.3—Fugitive emissions released from gas flared from the oil refinery

3.69 Method 1—gas flared from crude oil refining

(1) Method 1 is:

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

where:

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.

Q_i is the quantity of gas for the fuel type (***i***) flared during the year measured in tonnes.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

EF_ij is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of gas type (***j***) flared in the crude oil refining during the year.

(2) For ***EF_ij*** in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for gas type (***j***) for 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	0.133	0.026
2	Crude oil and liquids	3.2	0.009	0.06

3.70 Method 2—gas flared from crude oil refining

For subparagraph 3.63(4)(a)(ii), method 2 is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

E_{iCO_2} is the fugitive emissions of CO_2 from fuel type (***i***) flared in crude oil refining during the year, measured in CO_2-e tonnes.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, measured in tonnes in accordance with Division 2.3.3.

EF_h is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in the crude oil refining during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with method 2 in Division 2.3.3.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

QCO_2 is the quantity of CO_2 within the fuel type (***i***) in the crude oil refining during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

3.70A Method 2A—crude oil refining (flared methane or nitrous oxide emissions)

For subparagraphs 3.63(4)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

EF_{hij} is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, mentioned for the fuel type in the table in subsection 3.69(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

E_{ij} is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from crude oil refining during the year, measured in CO_2-e tonnes.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, measured in tonnes in accordance with Division 2.3.3.

3.71 Method 3—gas flared from crude oil refining

For subparagraph 3.63(4)(a)(iii), method 3 is the same as method 2 under section 3.70, 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 3.3.6A—Onshore natural gas production (other than emissions that are vented or flared)

3.72 Application

This Division applies to fugitive emissions from onshore natural gas production activities, other than emissions that are vented or flared, including emissions from onshore natural gas wellheads.

Subdivision 3.3.6A.1—Onshore natural gas production, other than emissions that are vented or flared—wellheads

3.73 Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by onshore natural gas production:

(a) method 1 under section 3.73A;

(b) method 2 under section 3.73B;

(c) method 3 under section 3.73C.

Note: There is no method 4 for this Division.

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

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6B, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility:

(a) all other available methods 3 must be used in Divisions 3.3.6B, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility; and

(b) if LDAR program emissions factors are elected—they are elected for all of the methods applicable to the facility.

3.73A Method 1 Onshore natural gas production, other than emissions that are vented or flared—wellheads

(1) Method 1 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk} \times S_{ij} / SD_{ij})$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the onshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, 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 onshore natural gas production.

Q_{ik} is the total of the quantities of unprocessed natural gas (***i***) that pass through each equipment type (***k***) specified in column 2 of the table in subsection (2), during the year measured in tonnes in accordance with Division 2.3.6.

EF_{ijk} is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per tonne of unprocessed natural gas (***i***) that passes through each equipment type (***k***), if the equipment is used in the onshore natural gas production during the year.

S_{ij} is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas ***(i),*** by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.98 and for carbon dioxide SD is 0.02.

(2) For EF_{ijk} in subsection (1), column 3 of an item in the following table specifies the emission factor for gas type (***j***) being methane for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Onshore natural gas wellheads	1.32×10^{-3}	2.60×10^{-6}	tonnes CO_2-e/t gas throughput

3.73B Method 2—Onshore natural gas production, other than emissions that are vented or flared—wellheads

(1) Method 2 is:

$$E_{ij} = \Sigma_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij}/SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the onshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, 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 onshore natural gas production.

T_{ik} is the average hours of operation during the year of the equipment of each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the onshore natural gas production during the year.

N_{ik} is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the onshore natural gas production during the year.

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the onshore natural gas production.

S_{ij} is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas ***(i)***, by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) For ***EF_{ijk}*** in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Gas wellheads	5.04×10^{-4}	1.25×10^{-6}	tonnes CO_2-e /equipment - hour
2	Gas separators	1.24×10^{-3}	3.08×10^{-6}	tonnes CO_2-e /equipment - hour
3	Gas heaters	1.29×10^{-3}	3.20×10^{-6}	tonnes CO_2-e /equipment - hour
4	Reciprocating compressor	4.60×10^{-2}	1.14×10^{-4}	tonnes CO_2-e /equipment - hour
5	Screw compressor	2.88×10^{-2}	7.15×10^{-5}	tonnes CO_2-e /equipment - hour
6	Meters	9.86×10^{-4}	2.45×10^{-6}	tonnes CO_2-e /equipment - hour
7	Dehydrators	2.00×10^{-3}	4.96×10^{-6}	tonnes CO_2-e /equipment - hour

3.73C Method 3—Onshore natural gas production, other than emissions that are vented or flared—wellheads

(1) Method 3 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the onshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the onshore natural gas production during the year.

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (2) or (3), if the component is used in the onshore natural gas production during the year.

N_{ik} is the total number of components of each component type (***k***) if the component type is used in the onshore natural gas production during the year.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in the onshore natural gas production;

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) Unless subsection (3) is elected and used for all components under this method, ***EF_{ijk}***, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item:

Item	**Component type (k)**	**Emission factor for gas type (j)**		
		CH_4	**CO_2**	**Units**
1	Valves – gas production	7.36×10^{-5}	1.83×10^{-7}	tonnes CO_2-e /component - hour
2	Connectors – gas production	8.99×10^{-6}	2.23×10^{-8}	tonnes CO_2-e / component - hour
3	Flanges – gas production	3.30×10^{-6}	8.22×10^{-9}	tonnes CO_2-e / component - hour

4	Open-ended lines – gas production	1.92×10^{-5}	4.78×10^{-8}	tonnes CO_2-e / component - hour
5	Pump Seals – gas production	5.46×10^{-6}	1.36×10^{-8}	tonnes CO_2-e / component - hour
6	Others – gas production	2.57×10^{-4}	6.40×10^{-7}	tonnes CO_2-e / component - hour

Note: These component types are listed in section 6.1.3 of the API Compendium.

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

(3) If an LDAR program has been carried out at the facility in relation to onshore natural gas production components in accordance with subsection (4) and this subsection elected for all components under this method, $\boldsymbol{EF_{ijk}}$, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves—non leaker	7.56×10^{-6}	1.88×10^{-8}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	1.39×10^{-5}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	5.22×10^{-8}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	2.44×10^{-5}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	9.75×10^{-10}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	8.36×10^{-6}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	5.64×10^{-9}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	1.46×10^{-5}	tonnes CO_2-e / component - hour

(4) For subsection (3) the LDAR program must survey each component used in onshore gas production at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.6B—Offshore natural gas production (other than emissions that are vented or flared)

3.73D Application

This Division applies to fugitive emissions from offshore natural gas production 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.

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Subdivision 3.3.6B.1—Offshore natural gas production, other than emissions that are vented or flared—offshore platforms

3.73E Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by offshore natural gas production:

(a) method 1 under section 3.73F;

(b) method 2 under section 3.73G;

(c) method 3 under section 3.73H.

Note: There is no method 4 for this Division.

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

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility:

(a) all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6C, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility ; and

(b) if LDAR program emissions factors are elected—they are elected for all of the methods applicable to the facility.

3.73F Method 1—offshore natural gas production (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk}) \times S_{ij}/SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the offshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, 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 offshore natural gas production.

Q_{ik} is the number of platforms of each equipment type (***k***) specified in column 2 of the table in subsection (2), during the year.

EF_{ijk} is the emission factor for gas type (***j***) measured in CO_2-e tonnes per platform during the year as determined under subsection (2), if the equipment is used in the offshore natural gas production.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***) where methane SD is 0.832 and carbon dioxide SD is 0.035.

(2) For ***EF_{ijk}*** in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (j) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Offshore platforms (shallow water)	1,747.1	7.10	tonnes CO_2-e /platform
2	Offshore platforms (deep water)	18,422.6	75.0	tonnes CO_2-e/ platform

3.73G Method 2—offshore natural gas production (other than venting and flaring)

(1) Method 2 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij}/SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the offshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the offshore natural gas production.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of the equipment of each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the offshore natural gas production during the year.

$\boldsymbol{N_{ik}}$ is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the offshore natural gas production during the year.

$\boldsymbol{EF_{ijk}}$ is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the offshore natural gas production.

$\boldsymbol{S_{ij}}$ is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(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 and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Gas wellheads	5.04×10^{-4}	1.25×10^{-6}	tonnes CO_2-e /equipment - hour
2	Gas separators	1.24×10^{-3}	3.08×10^{-6}	tonnes CO_2-e /equipment - hour
3	Gas heaters	1.29×10^{-3}	3.20×10^{-6}	tonnes CO_2-e /equipment - hour
4	Reciprocating compressor	4.60×10^{-2}	1.14×10^{-4}	tonnes CO_2-e /equipment - hour
5	Screw compressor	2.88×10^{-2}	7.15×10^{-5}	tonnes CO_2-e /equipment - hour
6	Meters	9.86×10^{-4}	2.45×10^{-6}	tonnes CO_2-e /equipment - hour
7	Dehydrators	2.00×10^{-3}	4.96×10^{-6}	tonnes CO_2-e /equipment - hour
8	Gathering pipelines	7.45×10^{-4}	1.85×10^{-6}	tonnes CO_2-e /kilometre - hour

3.73H Method 3—offshore natural gas production (other than emissions that are vented or flared)

(1) Method 3 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the offshore natural gas production during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the offshore natural gas production.

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (2) or (3), if the component is used in the offshore natural gas production.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in the offshore natural gas production; and

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of components of each component type (***k***) listed if the component type is used in the offshore natural gas production during the year.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) Unless subsection (3) is elected and used for all components under this method, ***EF_{ijk}***, the emission factors for methane (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item:

Item	Component type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves	1.44×10^{-5}	3.58×10^{-8}	tonnes CO_2-e /component - hour

2	Pump Seals	5.46×10^{-6}	1.36×10^{-8}	tonnes CO_2-e / component - hour
3	Others	1.94×10^{-4}	4.83×10^{-7}	tonnes CO_2-e / component - hour
4	Connectors	3.02×10^{-6}	7.52×10^{-9}	tonnes CO_2-e / component - hour
5	Flanges	5.52×10^{-6}	1.37×10^{-8}	tonnes CO_2-e / component - hour
6	Open-ended lines	2.83×10^{-5}	7.03×10^{-8}	tonnes CO_2-e / component - hour

Note: These component types are listed in section 6.1.3 of the API Compendium.

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

(3) If an LDAR program has been carried out at the facility in relation to offshore natural gas production components in accordance with subsection (4) and this subsection elected for all components under this method, $\boldsymbol{EF_{ijk}}$, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	**Component and leaker/non leaker type (k)**	**Emission factor for gas type (j)**		
		CH_4	**CO_2**	**Units**
1	Valves—non leaker	7.56×10^{-6}	1.88×10^{-8}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	1.39×10^{-5}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	5.22×10^{-8}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	2.44×10^{-5}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	9.75×10^{-10}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	8.36×10^{-6}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	5.64×10^{-9}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	1.46×10^{-5}	tonnes CO_2-e / component - hour

(4) For subsection (3) the LDAR program must survey each component used in offshore gas production at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.6C—Natural gas gathering and boosting (other than emissions that are vented or flared)

3.73I Application

This Division applies to fugitive emissions from natural gas gathering and boosting, other than emissions that are vented or flared, including emissions from natural gas gathering and boosting stations and pipelines.

Note: Division 3.3.6A applies to fugitive emissions from onshore natural gas production activities, other than emissions that are vented or flared, including emissions from wellheads.

3.73J Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas gathering and boosting:

- (a) method 1 under section 3.73K;
- (b) method 2 under section 3.73L;
- (c) method 3 under section 3.73M.

Note: There is no method 4 for this Division.

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

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility:

- (a) all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6E, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility; and
- (b) if LDAR program emissions factors are elected—they are elected for all of the methods applicable to the facility.

3.73K Method 1—Natural gas gathering and boosting (other than venting and flaring)

Method 1 is:

$$E_{ij} = E_{ijs} + E_{ijp}$$

where:

E**ij* is the fugitive emissions (other than emissions that are vented or flared) of gas type (j***), being methane or carbon dioxide, from the natural gas gathering and boosting during the year measured in CO_2-e tonnes.

E_{ijs} is the fugitive emissions (other than emissions that are vented or flared) of gas type (*j*), being methane or carbon dioxide, from the natural gas gathering and boosting stations (*s*) during the year measured in CO_2-e tonnes, given by section 3.73KA.

E_{ijp} is the fugitive emissions (other than emissions that are vented or flared) of gas type (*j*), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines (*p*) during the year measured in CO_2-e tonnes, given by section 3.73KB.

3.73KA Method 1—Natural gas gathering and boosting, other than emissions that are vented or flared—natural gas gathering and boosting stations

(1) For section 3.73K, E_{ijs} is given by the following formula:

$$E_{ijs} = \Sigma_{js}(Q_{is} \times EF_j) \times S_{ij} / SD_{ij}$$

where:

E_{ijs} is the fugitive emissions (other than emissions that are vented or flared) of gas type (*j*), being methane or carbon dioxide, from the natural gas gathering and boosting stations during the year measured in CO_2-e tonnes.

Σ_{js} is the total emissions of gas type (*j*), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each natural gas gathering and boosting station (*s*).

Q_{is} is the quantity of unprocessed natural gas (*i*) that passes through the natural gas gathering and boosting station (*s*) during the year, measured in tonnes in accordance with Division 2.3.6.

EF_j is the emission factor for gas type (*j*), being methane or carbon dioxide, measured in CO_2-e tonnes per tonne of unprocessed natural gas that passes through each natural gas gathering and boosting station (*s*) given by subsection (2) or (3).

S_{ij} is the measured share of each gas type (*j*), being methane or carbon dioxide, in the unprocessed gas (*i*), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (*j*) in the unprocessed gas (*i*), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(2) For EF_j in subsection (1), EF_j for methane is given by the following formula:

$$EF_j = GWP_{methane} \times 2.386 \times Q_i^{-0.761}$$

where:

EF_j is the emission factor for methane (j) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas gathering and boosting station during the year.

Q_i is the quantity of unprocessed natural gas that passes through the natural gas gathering and boosting station during the year, measured in tonnes in accordance with Division 2.3.6.

(3) For $\boldsymbol{EF_j}$ in subsection (1), $\boldsymbol{EF_j}$ for carbon dioxide is given by the following formula:

$$EF_j = 2.386 \times Q_i^{-0.761} \times SD_{ij=\text{carbon dioxide}} / SD_{ij=\text{methane}}$$

where:

$\boldsymbol{EF_j}$ is the emission factor for carbon dioxide (j) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas gathering and boosting station during the year.

$\boldsymbol{Q_i}$ is the quantity of unprocessed natural gas that passes through the natural gas gathering and boosting station during the year, measured in tonnes in accordance with Division 2.3.6.

$\boldsymbol{SD_{ij=carbon\ dioxide}}$ is the default share of carbon dioxide (***j***) in the unprocessed gas (***i***), which is 0.0345.

$\boldsymbol{SD_{ij=methane}}$ is the default share of methane (***j***) in the unprocessed gas (***i***), which is 0.832.

3.73KB Method 1—Natural gas gathering and boosting, other than emissions that are vented or flared—natural gas gathering and boosting pipelines

(1) For section 3.73K, subject to subsection (3), E_{ijp} is given by the following formula:

$$E_{ijp} = P_k \times EF_{ijk} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines during the year measured in CO_2-e tonnes.

$\boldsymbol{P_k}$ is the length of the system of gathering and boosting pipelines of type (***k***) during the year measured in kilometres and used in the natural gas gathering and boosting.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per tonne of natural gas that passes through each equipment type (***k***), or CO_2-e tonnes per kilometre of pipeline if the equipment is used in the natural gas gathering and boosting pipelines during the year.

$\boldsymbol{S_{ij}}$ is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(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 and column 4 of an item in the following table specifies the

emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Onshore gas gathering and boosting pipelines	6.52	2.65×10^{-2}	tonnes CO_2-e /kilometres of pipeline

(3) However, $\boldsymbol{E_{ijp}}$ may also be calculated by the method in section 3.73LB.

3.73L Method 2—Natural gas gathering and boosting (other than venting and flaring)

Method 2 is:

$$E_{ij} = E_{ijs} + E_{ijp}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting during the year measured in CO_2-e tonnes.

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations (***s***) during the year measured in CO_2-e tonnes given by section 3.73LA.

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines (***p***) during the year measured in CO_2-e tonnes, given by section 3.73LB.

3.73LA Method 2—Natural gas gathering and boosting, other than emissions that are vented or flared—natural gas gathering and boosting stations

(1) For section 3.73L, E_{ijs} is given by the following formula:

$$E_{ijs} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijs}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas gathering and boosting station.

T_{ik} is the average hours of operation during the year of the equipment of each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas gathering and boosting station during the year.

N_{ik} is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas gathering and boosting station during the year.

EF_{ijk} is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the natural gas gathering and boosting station.

S_{ij} is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, passing through the gathering and boosting station measured in accordance Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(2) For ***EF_{ijk}*** in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Gas separators	1.24×10^{-3}	3.08×10^{-6}	tonnes CO_2-e /equipment - hour
2	Gas heaters	1.29×10^{-3}	3.20×10^{-6}	tonnes CO_2-e /equipment - hour
3	Reciprocating compressor	4.60×10^{-2}	1.14×10^{-4}	tonnes CO_2-e /equipment - hour
4	Screw compressor	2.88×10^{-2}	7.15×10^{-5}	tonnes CO_2-e /equipment - hour
5	Meters	9.86×10^{-4}	2.45×10^{-6}	tonnes CO_2-e /equipment - hour
6	Dehydrators	2.00×10^{-3}	4.96×10^{-6}	tonnes CO_2-e /equipment - hour

3.73LB Method 2—Onshore natural gas production, other than emissions that are vented or flared—onshore gas gathering and boosting pipelines

(1) For section 3.73L and subsection 3.73M(1), E_{ijp} is given by the following formula:

$$E_{ijp} = \sum_k T_{ik} \times P_k \times EF_{ijk} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ijp}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, 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 natural gas gathering and boosting.

$\boldsymbol{T_{ik}}$ is the average hours of operation during the year of the equipment of each equipment type (***k***) specified in column 2 of the table in subsection (2), if the equipment is used in natural gas gathering and boosting during the year.

$\boldsymbol{P_k}$ is the length of the system of gathering and boosting pipelines of type (***k)*** during the year measured in kilometres and used in natural gas gathering and boosting.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes per kilometre-hour of pipeline type (***k***), if the equipment is used in natural gas gathering and boosting.

$\boldsymbol{S_{ij}}$ is the measured share of each gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, that passes though the equipment measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(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 and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Onshore gas gathering and boosting pipelines (cast iron)	7.72×10^{-3}	3.14×10^{-5}	tonnes CO_2-e /kilometres of pipeline hour
2	Onshore gas gathering and boosting pipelines (plastic)	6.99×10^{-4}	2.85×10^{-6}	tonnes CO_2-e /kilometres of pipeline hour
3	Onshore gas gathering and boosting pipelines (protected steel)	1.31×10^{-4}	5.34×10^{-7}	tonnes CO_2-e /kilometres of pipeline hour

4	Onshore gas gathering and boosting pipelines (unprotected steel)	4.64×10^{-3}	1.89×10^{-5}	tonnes CO_2-e /kilometres of pipeline hour

3.73M Method 3—Natural gas gathering and boosting (other than venting and flaring)

(1) Method 3 is:

$$E_{ij} = E_{ijs} + E_{ijp}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting during the year measured in CO_2-e tonnes.

E_{ijs} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting stations (***s***) during the year measured in CO_2-e tonnes, given by subsection (2).

E_{ijp} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting pipelines (***p***) during the year measured in CO_2-e tonnes, given by section 3.73LB.

(2) For subsection (1), E_{ijs} is given by the following formula:

$$E_{ijs} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ijs} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas gathering and boosting station during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the natural gas gathering and boosting stations (***s***).

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (3) or (4), if the component is used in the natural gas gathering and boosting station.

T_{ik} is:

(a) if subsection (3) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in natural gas gathering and boosting;

(b) if subsection (4) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of components of each component type (***k***), if the component type is used in natural gas gathering and boosting.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.788 and for carbon dioxide SD is 0.02.

(3) Unless subsection (4) is elected and used for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item:

Item	Component type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves – gas production	7.36×10^{-5}	1.83×10^{-7}	tonnes CO_2-e /component - hour
2	Connectors – gas production	8.99×10^{-6}	2.23×10^{-8}	tonnes CO_2-e / component - hour
3	Flanges – gas production	3.30×10^{-6}	8.22×10^{-9}	tonnes CO_2-e / component - hour
4	Open-ended lines – gas production	1.92×10^{-5}	4.78×10^{-8}	tonnes CO_2-e / component - hour
5	Pump Seals – gas production	5.46×10^{-6}	1.36×10^{-8}	tonnes CO_2-e / component - hour
6	Others – gas production	2.57×10^{-4}	6.40×10^{-7}	tonnes CO_2-e / component - hour

Note: These component types are listed in section 6.1.3 of the API Compendium..

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

(4) If an LDAR program has been carried out at the facility in relation to natural gas gathering and boosting components in accordance with subsection (5) and this subsection elected for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves—non leaker	7.56×10^{-6}	1.88×10^{-8}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	1.39×10^{-5}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	5.22×10^{-8}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	2.44×10^{-5}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	9.75×10^{-10}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	8.36×10^{-6}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	5.64×10^{-9}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	1.46×10^{-5}	tonnes CO_2-e / component - hour

(5) For subsection (4) the LDAR program must survey each component used in natural gas gathering and boosting at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method.

(6) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.6D—Produced water from oil and gas exploration and development, crude oil production, natural gas production or natural gas gathering and boosting (other than emissions that are vented or flared)

3.73N 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 produced water relating to the operation of a facility that is constituted by a relevant activity:

(a) method 1 under section 3.73NA;

(b) method 2 under section 3.73NB.

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.

(3) In this Division, a ***relevant activity*** is oil or gas exploration and development, crude oil production, natural gas gathering and boosting or onshore or offshore natural gas production.

3.73NA Method 1— Produced water (other than emissions that are vented or flared)

Method 1 is:

$$E_{ij} = W_{\mathbf{i}} \times EF_{ijw} \times S_{ij} / SD_{ij}$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) being methane from the produced water during the year measured in CO_2-e tonnes.

$\boldsymbol{W_i}$ is the total quantity of produced water during the year associated with the relevant activity measured in megalitres of produced water.

$\boldsymbol{EF_{ijw}}$ is the emission factor for gas type (***j***), being methane, of 7.99 tonnes of CO_2-e per megalitre of produced water associated with relevant activity during the year.

$\boldsymbol{S_{ij}}$ is the measured share of gas type (***j***) being methane in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832.

3.73NB Method 2— Produced water (other than emissions that are vented or flared)

(1) Method 2 is:

$$E_{ij} = W_{\mathbf{i}} \times EF_{ijw} \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) being methane from the produced water from the relevant activity during the year measured in CO_2-e tonnes.

W_i is the total quantity of produced water during the year associated with the relevant activity measured in megalitres of produced water.

EF_{ijw} is the emission factor for gas type (***j***), being methane, measured in CO_2-e tonnes per megalitre of produced water associated with the relevant activity during the year as determined under subsection (2).

S_{ij} is the measured share of gas type (***j***) being methane in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832.

(2) For ***EF_{ijw}***, in subsection (1):

(a) if the average pressure for a water stream entering the separator during the year (***WP***) is less than 345 kilopascals and:

(i) the average salinity content of the water is less than or equal to 20 000 milligrams per litre during the year—0.8707 tonnes of CO_2-e tonnes per megalitre of produced water associated with the relevant activity; or

(ii) the average salinity content of the water is less than or equal to 100 000 milligrams per litre and greater than or equal to 20 000 milligrams per litre during the year—0.7439 tonnes of CO_2-e tonnes per megalitre of produced water associated with the relevant activity; or

(iii) the average salinity content of the water is greater than 100 000 milligrams per litre during the year—0.3212 tonnes of CO_2-e tonnes per megalitre of produced water associated with the relevant activity; or

(b) if the average pressure for a water stream entering the separator during the year (***WP***) is equal to or greater than 345 kilopascals—is calculated under subsection (3); and

(3) For paragraph (2)(b):

(a) if the average salinity content of the water is less than or equal to 20 000 milligrams per litre during the year—***EF_{ijw}***, is given by the following formula:

$$E_{ijw} = WP \times 0.0016 + 0.4342$$

(b) if the average salinity content of the water is less than or equal to 100 000 milligrams per litre and greater than or equal to 20 000 milligrams per litre during the year—$\boldsymbol{EF_{ijw}}$, is given by the following formula:

$$E_{ijw} = WP \times 0.0013 + 0.3695$$

(c) if the average salinity content of the water is greater than 100 000 milligrams per litre during the year—$\boldsymbol{EF_{ijw}}$, is given by the following formula:

$$E_{ijw} = WP \times 0.0009 + 0.0507$$

where:

$\boldsymbol{EF_{ijw}}$ is the emission factor for gas type ($\boldsymbol{j}$), being methane, measured in CO_2-e tonnes per megalitre of produced water associated with the relevant activity during the year.

WP is the average pressure for a water stream entering the separator during the year measured in kilopascals.

Division 3.3.6E—Natural gas processing (other than emissions that are vented or flared)

3.73O Application

This Division applies to fugitive emissions from natural gas processing activities, other than emissions that are vented or flared, including emissions from gas processing.

3.73P Available methods

(1) Subject to section 1.18 and subsections (3) and (4), one of the following methods must be used for estimating fugitive emissions of methane and carbon dioxide (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas processing:

(a) method 1 under section 3.73Q;

(b) method 2 under section 3.73R;

(c) method 3 under section 3.73S.

Note: There is no method 4 for this Division.

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

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility:

(a) all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.7A and 3.3.7B if those Divisions are applicable to the facility; and

(b) if LDAR program emissions factors are elected—they are elected for all of the methods applicable to the facility.

3.73Q Method 1—natural gas processing (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \Sigma_{js}(Q_{is} \times EF_{ijs}) \times S_{ij/}SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas processing during the year, measured in CO_2-e tonnes.

Σ_{js} is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each natural gas processing station (***s***).

$\boldsymbol{Q_{is}}$ is the quantity of unprocessed natural gas (***i***) that passes through the natural gas processing station (***s***) during the year, measured in tonnes, in accordance with Division 2.3.6.

$\boldsymbol{EF_{ijs}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, for the unprocessed natural gas (***i***) that passes through the natural gas processing station (***s***) during the year as determined under subsection (2) or (3), measured in tonnes of gas (leakage) per tonne of gas throughput.

$\boldsymbol{S_{ij}}$ is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.832 and for carbon dioxide SD is 0.0345.

(2) For $\boldsymbol{EF_{ij}}$ in subsection (1), $\boldsymbol{EF_{ij}}$ for methane is given by the following formula:

$$EF_{ij} = GWP_{methane} \times 0.6369 \times Q_i^{-0.4801}$$

where:

$\boldsymbol{EF_{ij}}$ is the emission factor for methane (***j***) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas processing station during the year.

$\boldsymbol{Q_i}$ is the quantity of unprocessed natural gas that passes through the natural gas processing station during the year, measured in tonnes in accordance with Division 2.3.6.

(3) For $\boldsymbol{EF_{ij}}$ in subsection (1), $\boldsymbol{EF_{ij}}$ for carbon dioxide is given by the following formula:

$$EF_{ij} = 0.6369 \times Q_i^{-0.4801} \times SD_{ij=carbon\ dioxide} / SD_{ij=methane}$$

where:

$\boldsymbol{EF_{ij}}$ is the emission factor for carbon dioxide (j) measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas gathering and boosting station during the year.

$\boldsymbol{Q_i}$ is the quantity of unprocessed natural gas that passes through the natural gas gathering and boosting station during the year, measured in tonnes in accordance with Division 2.3.6.

$\boldsymbol{SD_{ij=carbon\ dioxide}}$ is the default share of carbon dioxide (***j***) in the unprocessed gas (***i***), which is 0.0345.

$\boldsymbol{SD_{ij=methane}}$ is the default share of methane (***j***) in the unprocessed gas (***i***), which is 0.832.

3.73R Method 2—natural gas processing (other than venting and flaring)

(1) Method 2 is:

$$E_{ij} = [\sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij}/SD_{ij}]$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas processing during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas processing.

T_{ik} is the average hours of operation during the year of the equipment of each equipment type (***k***) listed in sections 6.1.2 of the API Compendium, if the equipment is used in the natural gas processing during the year.

N_{ik} is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas processing during the year.

EF_{ijk} is the emission factor (***A***) of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per equipment type (***k***) – hour as determined under subsection (2), if the equipment is used in the natural gas processing.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.868 and for carbon dioxide SD is 0.0345.

(2) For ***EF_{Aijk}*** 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 and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item.

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Reciprocating compressors	7.66×10^{-2}	1.91×10^{-4}	tonnes CO_2-e /equipment - hour
2	Centrifugal compressors (wet seals)	1.54	5.99×10^{-3}	tonnes CO_2-e /equipment - hour
3	Centrifugal compressors (dry seals)	0.194	7.54×10^{-4}	tonnes CO_2-e /equipment - hour
4	Screw compressors	2.97×10^{-2}	1.16×10^{-4}	tonnes CO_2-e /equipment - hour

3.73S Method 3—natural gas processing (other than venting and flaring)

(1) Method 3 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk}) \times S_{ij} / SD_{ij}$$

where:

E_{ij} is the fugitive emissions (other than venting and flaring) of gas type (***j***), being methane or carbon dioxide, from the natural gas processing during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the natural gas processing.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in natural gas processing; or

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of components of each component type (***k***) if the component type is used in the natural gas processing during the year.

EF_{ijk} is the emission factor of gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per component-hour for each component type (***k***) as determined under subsection (2) or (3), if the component is used in the natural gas processing.

S_{ij} is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

SD_{ij} is the default share of gas type (***j***) in the unprocessed gas (***i***) for methane SD is 0.868 and for carbon dioxide SD is 0.0345.

(2) Unless subsection (3) is elected and used for all components under this method, EF_{ijk}, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component type (***k***) specified in column 2 of that item; or

Item	Component type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units

1	Valves	1.08×10^{-4}	4.21×10^{-7}	tonnes CO_2-e /component - hour
2	Pump Seals	3.22×10^{-4}	1.25×10^{-6}	tonnes CO_2-e / component - hour
3	Others	1.36×10^{-4}	5.30×10^{-7}	tonnes CO_2-e / component - hour
4	Connectors	7.67×10^{-6}	2.99×10^{-8}	tonnes CO_2-e / component - hour
5	Flanges	1.23×10^{-5}	4.78×10^{-8}	tonnes CO_2-e / component - hour
6	Open-ended lines	2.88×10^{-5}	1.12×10^{-7}	tonnes CO_2-e / component - hour

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

(3) If an LDAR program has been carried out at the facility in relation to natural gas processing components in accordance with subsection (4) and this subsection elected for all components under this method, $\boldsymbol{EF_{ijk}}$, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	**Component and leaker/non leaker type (k)**	**Emission factor for gas type (j)**		
		CH_4	**CO_2**	**Units**
1	Valves—non leaker	7.56×10^{-6}	2.94×10^{-08}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	2.18×10^{-05}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	8.18×10^{-08}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	3.82×10^{-05}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	1.53×10^{-09}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	1.31×10^{-05}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	8.83×10^{-09}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	2.29×10^{-05}	tonnes CO_2-e / component - hour

(4) For subsection (3) the LDAR program must survey each component used in natural gas processing at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.7—Natural gas transmission (other than emissions that are flared)

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 (other than flaring) 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;

(c) method 3 under section 3.78.

Note: There is no method 4 for this Division.

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

3.76 Method 1—natural gas transmission (other than flaring)

Method 1 is:

$$E_{ij} = (L_i \times EF_{ij})$$

where:

E_{ij} is the fugitive emissions (other than flaring) 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.

L_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 11.6 for methane, measured in tonnes of CO_2-e emissions per kilometre of pipeline (***i***).

3.77 Method 2—natural gas transmission (other than flaring)

(1) Method 2 is:

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

where:

E_j is the fugitive emissions (other than flaring) of gas type (***j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.

Σ_k is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission.

Q_k is the total of the quantities of natural gas or plant condensate 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 during the year.

N_k is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas transmission during the year.

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 as determined under subsection (2), where the equipment is used in the natural gas transmission.

(2) For ***EF_{jk}***, the emission factors for a gas type (***j***) as the natural gas or plant condensate 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; or

(e) estimated using the engineering calculation approach in accordance with sections 5 and 6.1.2 of the API Compendium.

Note: In 2021, the API Compendium was available at www.api.org.

3.78 Method 3—natural gas transmission (other than flaring)

(1) Method 3 is:

$$E_j = \sum\nolimits_k (T_k \times N_k \times EF_{jk})$$

where:

E_{ij} is the fugitive emissions (other than flaring) of gas type (***j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.

Σ_k is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component is used in the natural gas transmission.

$\boldsymbol{T_k}$ is the average hours of operation during the year of the components of each component type (***k***) listed in section 6.1.3 of the API Compendium, if the component is used in the natural gas transmission during the year.

$\boldsymbol{N_k}$ is the total number of components of each component type (***k***) listed in section 6.1.3 of the API Compendium if the component type is used in the natural gas transmission during the year.

$\boldsymbol{EF_{jk}}$ is the emission factor of gas type (***j***) measured in CO_2-e tonnes for each component type (***k***) listed in 6.1.3 of the API Compendium as determined under subsection (2), where the component is used in the natural gas transmission.

(2) For $\boldsymbol{EF_{jk}}$, the emission factors for gas type (***j***), as natural gas or plant condensate passes through a component type (***k***), are:

(a) as listed in Table 6-18 in section 6.1.3 of the API Compendium, for the component type; or

(b) as listed in that Compendium for the component type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Table 6-18 in section 6.1.3, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the component type with emission factors adjusted for variations in the type of component 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 component supplies component-specific emission factors for the component type—those factors; or

(e) estimated using the engineering calculation approach in accordance with section 6.1.3 of the API Compendium.

Note: In 2021, the API Compendium was available at www.api.org.

Division 3.3.7A—Natural gas storage (other than emissions that are vented or flared)

3.78A Application

This Division applies to fugitive emissions (other than emissions that are vented or flared) from natural gas storage.

3.78B Available methods

(1) Subject to section 1.18 and subsection (3) and (4), one of the following methods must be used for estimating fugitive emissions (other than emissions that are vented or flared) of each gas type, being carbon dioxide and methane, released from the operation of a facility that is constituted by natural gas storage during a year:

(a) method 1 under section 3.78C;

(b) method 2 under section 3.78D;

(c) method 3 under section 3.78E.

Note: There is no method 4 for this Division.

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

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7B if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility:

(a) all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7B if those Divisions are applicable to the facility; and

(b) if LDAR program emissions factors are elected—they are elected for all of the methods applicable to the facility.

3.78C Method 1—natural gas storage (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***), being methane or carbon dioxide, from the natural gas storage during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***), being methane or carbon dioxide, 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 storage.

Q_{ik} is the total number of each equipment type (***k***) specified in column 2 of the table in subsection (2).

EF_{ijk} is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in tonnes of gas type (***j***) per equipment type (***k***) during the year, as determined under subsection (2), if the equipment is used in the natural gas storage.

(2) For ***EF_{ijk}*** in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Natural gas storage station	10,336	20.7	tonnes CO_2-e per station

3.78D Method 2—natural gas storage (other than emissions that are vented or flared)

(1) Method 2 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of methane or carbon dioxide (***j***) from the natural gas storage during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane or carbon dioxide (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas storage.

T_{ik} is the average hours of operation during the year of each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas storage during the year.

N_{ik} is the total number of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas storage during the year.

EF_{ijk} is the emission factor of methane or carbon dioxide (***j***) measured in tonnes of CO_2-e per equipment type (***k***) – hour listed in Table 6-6 of section 6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the natural gas storage.

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), column 3 of an item in the following table specifies the emission factor for methane or carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**		
		CH_4	CO_2	Units
1	Natural gas storage station	0.482	1.01×10^{-3}	tonnes CO_2-e per equipment – hour
2	Reciprocating compressor	0.473	9.93×10^{-4}	tonnes CO_2-e per equipment – hour
3	Centrifugal compressor	0.683	1.43×10^{-3}	tonnes CO_2-e per equipment – hour
4	Screw compressor	2.88×10^{-2}	6.03×10^{-5}	tonnes CO_2-e per equipment – hour

3.78E Method 3—natural gas storage (other than emissions that are vented or flared)

(1) Method 3 is:

$$E_j = \sum_k (T_k \times EF_{jk} \times N_k)$$

where:

$\boldsymbol{E_j}$ is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) measured in CO_2-e tonnes from the natural gas storage during the year.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each component type (***k***), if the component is used in the natural gas storage.

$\boldsymbol{EF_{jk}}$ is the emission factor of gas type (***j***) measured in tonnes of CO_2-e per component-hour that passes through each component type (***k***) as determined under subsection (2) or (3), if the component is used in the natural gas storage.

$\boldsymbol{T_k}$ is:

(a) if subsection (2) applies—the average hours of operation during the year of the component of each component type (***k***), if the component is used in the onshore natural gas storage; or

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

$\boldsymbol{N_{ik}}$ is the total number of each component type (***k***) listed in section 6.1.3 of the API Compendium if the component type is used in the natural gas storage during the year.

(2) Unless subsection (3) is elected and used for all components under this method, ***EF**$_{ijk}$*, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) as listed in Table 6-18 in section 6.1.3 of the API Compendium, for the component type; or

(b) as listed in that Compendium for the component type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Table 6-18 in section 6.1.3, and the requirements of Division 2.3.3; or

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

Note: In 2021, the API Compendium was available at www.api.org.

(3) If an LDAR program has been carried out at the facility in relation to natural gas storage components in accordance with subsection (4) and this subsection elected for all components under this method, ***EF**$_{ijk}$*, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	**Component and leaker/non leaker type (k)**	**Emission factor for gas type (j)**		
		CH_4	**CO_2**	**Units**
1	Valves—non leaker	7.56×10^{-6}	2.94×10^{-08}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	2.18×10^{-05}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	8.18×10^{-08}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	3.82×10^{-05}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	1.53×10^{-09}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	1.31×10^{-05}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	8.83×10^{-09}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	2.29×10^{-05}	tonnes CO_2-e / component - hour

(4) For subsection (3) the LDAR program must survey each component used in natural gas storage at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.7B—Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)

3.78F Application

This Division applies to fugitive emissions from natural gas liquefaction, storage and transfer (other than emissions that are vented or flared).

3.78G Available methods

(1) Subject to section 1.18 and subsection (3) and (4), one of the following methods must be used for estimating fugitive emissions (other than emissions that are vented or flared), being methane, released from the operation of a facility that is constituted by natural gas liquefaction, storage and transfer during the year:

(a) method 1 under section 3.78H;

(b) method 2 under section 3.78I.

(b) method 3 under section 3.78J.

Note: There is no method 4 for this Division.

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

(3) If method 2 is used for a facility, all other available methods 2 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7A if those Divisions are applicable to the facility.

(4) If method 3 is used for a facility:

(a) all other available methods 3 must be used in Divisions 3.3.6A, 3.3.6B, 3.3.6C, 3.3.6E and 3.3.7A if those Divisions are applicable to the facility; and

(b) if LDAR program emissions factors are elected—they are elected for all of the methods applicable to the facility.

3.78H Method 1 – Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)

(1) Method 1 is:

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

where:

E_{ij} is the fugitive emissions (other than emissions that are vented or flared) of gas type (***j***) being methane (other than emissions that are vented or flared) from the natural gas liquefaction, storage and transfer during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of gas type (***j***) being methane, 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 liquefaction, storage and transfer.

Q_{ik} is the total of each equipment type (***k***) specified in column 2 of the table in subsection (2).

EF_{ijk} is the emission factor for gas type (***j***) measured in CO_2-e tonnes per equipment type (***k***) during the year if the equipment is used in the natural gas liquefaction, storage and transfer.

(2) For ***EF_{ijk}*** in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j)**	
		CH_4	Units
1	Liquefied natural gas station	25,700	tonnes CO_2-e per station

3.78I Method 2— Natural gas liquefaction, storage and transfer (other than emissions that are vented or flared)

(1) Method 2 is:

$$E_{ij} = \sum_k (T_{ik} \times N_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions (other than venting and flaring) of methane (***j***) from the natural gas liquefaction, storage and transfer during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas liquefaction, storage and transfer.

T_{ik} is the average hours of operation during the year of each equipment type (***k***) listed in section 6.1.2 of the API Compendium, if the equipment is used in the natural gas liquefaction, storage and transfer.

N_{ik} is the total number of equipment units of each equipment type (***k***) listed in section 6.1.2 of the API Compendium if the equipment type is used in the natural gas liquefaction, storage and transfer during the year.

EF_{ijk} is the emission factor of methane (***j***) measured in tonnes of CO_2-e per equipment type (***k***) – hour listed in section 6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the natural gas liquefaction, storage and transfer.

(2) For ***EF_{ijk}***, the emission factors for methane (***j***) as the natural gas passes through the equipment types (***k***) are:

(a) as listed in Table 6-6 of section 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.

3.78J Method 3— Natural gas liquefaction, storage and transfer (other than venting and flaring)

(1) Method 3 is:

$$E_{ij} = \sum\nolimits_k (T_{ik} \times N_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions (other than venting and flaring) of methane (***j***) from the natural gas liquefaction, storage and transfer during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from each component type (***k***), if the component type is used in the natural gas liquefaction, storage and transfer.

T_{ik} is:

(a) if subsection (2) applies—the average hours of operation during the year of the components of each component type (***k***) listed in table 13 in section 4.3.1 of the *API LNG Operations Consistent Methodology for Estimating Greenhouse Gas Emissions* published by the American Petroleum Institute, if the component is used in the natural gas liquefaction, storage and transfer during the year; or

(b) if subsection (3) applies—an engineering estimate of the number of hours in the year the component type (***k***) was operational as a leaker or non leaker based on the best available data and subsection (4).

N_{ik} is the total number of components of each component type (***k***), if the component type is used in the natural gas liquefaction, storage and transfer during the year.

Note: In 2021, the API document could be accessed at www.api.org.

EF_{ijk} is the emission factor of methane (***j***) measured in tonnes of CO_2-e per component type (***k***) – hour, if the component is used in the natural gas liquefaction, storage and transfer.

(2) Unless subsection (3) is elected and used for all components under this method, ***EF_{ijk}***, the emission factors for methane (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table, which specifies the emission factor for a component of type (***k***) specified in column 2 of that item: or

Item	Component type (k)	Emission factor for gas type (j)	
		CH_4	**Units**
1	Valve	6.40×10^{-4}	tonnes CO_2-e /hour/component

2	Pump Seal	2.15×10^{-3}	tonnes CO_2-e /hour/component
3	Connectors (flanges and threaded fittings)	1.83×10^{-4}	tonnes CO_2-e /hour/component
4	Other	9.52×10^{-4}	tonnes CO_2-e /hour/compressor
5	Vapour Recovery Compressors	2.24×10^{-3}	tonnes CO_2-e /hour/compressor

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

(3) If an LDAR program has been carried out at the facility in relation to natural gas liquefaction, storage and transfer components in accordance with subsection (4) and this subsection elected for all components under this method, $\boldsymbol{EF_{ijk}}$, the emission factors for methane or carbon dioxide (***j***), for component type (***k***), are:

(a) column 3 of an item in the following table specifies the emission factor for methane (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item; and

(b) column 4 of an item in the following table specifies the emission factor for carbon dioxide (***j***) for a component and leaker/non-leaker type (***k***) specified in column 2 of that item:

Item	Component and leaker/non leaker type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	Units
1	Valves—non leaker	7.56×10^{-6}	5.23×10^{-08}	tonnes CO_2-e /component - hour
2	Values—leaker	5.60×10^{-3}	3.88×10^{-05}	tonnes CO_2-e / component - hour
3	Pumps—non leaker	2.10×10^{-5}	1.45×10^{-07}	tonnes CO_2-e / component - hour
4	Pumps—leaker	9.80×10^{-3}	6.78×10^{-05}	tonnes CO_2-e / component - hour
5	Flanges—non leaker	3.92×10^{-7}	2.71×10^{-09}	tonnes CO_2-e / component - hour
6	Flanges—leaker	3.36×10^{-3}	2.33×10^{-05}	tonnes CO_2-e / component - hour
7	Other—non leaker	2.27×10^{-6}	1.57×10^{-08}	tonnes CO_2-e / component - hour
8	Other—leaker	5.88×10^{-3}	4.07×10^{-05}	tonnes CO_2-e / component - hour

(4) For subsection (3) the LDAR program must survey each component used in natural gas liquefaction, storage and transfer at the facility at least once in a reporting year in accordance with:

(a) paragraph 98.234(a)(1) of Title 40, Part 98 of the Code of Federal Regulations, United States of America using optical gas imaging with a sensitivity of 60 grams per hour; or

(b) the method outlined in USEPA Method 21—*Determination of organic volatile compound leaks*, as set out in Appendix A-7 of Title 40, Part 60 of the Code of Federal Regulations, United States of America where a leaker is detected if 10,000 parts per million or greater is measured consistent with that method.

(5) To determine whether a component is a leaker or non leaker at a period of time:

(a) if a leak is detected in a survey the component is assumed to leak from the later of the beginning of the reporting year or last survey where it was a non leaker; and

(b) after a leak is detected in a survey the component is assumed to leak until the earlier of the end of the reporting year or the next survey where it is a non leaker.

Division 3.3.8—Natural gas distribution (other than emissions that are flared)

3.79 Application

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

3.80 Available methods

(1) Subject to section 1.18 and subsections (2) and (3), one of the following methods must be used for estimating fugitive emissions (other than emissions that are flared) 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 3.81;

(b) method 2 under section 3.82;

(c) method 3 under section 3.82A.

Note: There is no method 4 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 3 may only be used if the percentage of unaccounted for gas for a facility is calculated or determined during a reporting year in accordance with gas market rules or procedures applicable to the facility.

Note: A percentage of unaccounted for gas is generally worked out under procedures made by the Australian Energy Market Operator and available on their website: www.aemo.com.au

3.81 Method 1—natural gas distribution

(1) Method 1 is:

$$E_{jp} = S_p \times \%UAG_p \times 0.55 \times C_{jp}$$

where:

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

$\boldsymbol{S_p}$ is the total sales during the year from the pipeline system in a State or Territory (***p***), 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 %UAGp in method 1 represents the proportion of gas that is unaccounted for and released as emissions.

C_{jp} is the natural gas composition factor for gas type (***j***) for the natural gas supplied from the pipeline system in a State or Territory (***p***), measured in CO_2-e tonnes per terajoule.

(2) For %UAGp in subsection (1), column 3 of an item in the following table specifies the percentage of unaccounted for gas in the pipeline system in a State or Territory specified in column 2 of that item.

(3) For C_{jp} 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 $CO_{2\text{-e}}$/TJ)	
		UAGp	CO_2	CH_4
1	NSW and ACT	2.2	0.8	437
2	VIC	3.0	0.9	435
3	QLD	1.7	0.8	423
4	WA	2.9	1.1	408
5	SA	4.9	0.8	437
6	TAS	0.2	0.9	435
7	NT	2.2	0.0	352

3.82 Method 2—natural gas distribution

(1) Method 2 is:

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

where:

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

Σ_k is the total of emissions of gas type (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

Q_k is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (***k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

EF_{jk} is the emission factor for gas type (***j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium as determined under subsection (2), if the equipment is used in the natural gas distribution.

(2) For EF_{jk}, the emission factors for gas type (***j***) as the natural gas passes through the equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium; or

(b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Sections 5 and 6.1.2, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material 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 3.82(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.

3.82A Method 3—natural gas distribution

(1) Method 3 is:

$$E_{jp} = S_p \times \%UAG_p \times 0.55 \times C_{jp}$$

where:

$\boldsymbol{E_{jp}}$ is the fugitive emissions (other than emissions that are flared) of gas type (***j***) that result from natural gas distribution through a system of pipelines with sales of gas in a State or Territory (***p***) during the year, measured in CO_2-e tonnes.

$\boldsymbol{S_p}$ is the total sales during the year from the pipeline system in a State or Territory (***p***), measured in terajoules.

$\boldsymbol{\%UAG_p}$ is the percentage of unaccounted for gas in the pipeline system in a State or Territory (***p***), relative to the amount of gas issued annually by gas utilities to that system.

$\boldsymbol{C_{jp}}$ is the natural gas composition factor for gas type (***j***) for the natural gas supplied from the pipeline system in a State or Territory (***p***), measured in CO_2-e tonnes per terajoule.

(2) For $\boldsymbol{\%UAG_p}$ in subsection (1):

(a) if at the time of reporting the percentage of unaccounted for gas for the reporting year has been calculated or determined in accordance with gas market rules or procedures applicable to the facility—the percentage calculated or determined in accordance with those rules or procedures; or

(b) if at the time of reporting the percentage of unaccounted for gas for the reporting year has not been calculated or determined in accordance with gas market rules or procedures applicable to the facility—the percentage applicable to the most recent 12 month period for which the percentage of unaccounted for gas has been calculated or determined.

(3) For C_{jp} in subsection (1), columns 3 and 4 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**	**Natural gas composition factor (a)(tonnes CO_{2-e}/TJ)**	
		CO_2	**CH_4**
1	NSW and ACT	0.8	437
2	VIC	0.9	435
3	QLD	0.8	423
4	WA	1.1	408
5	SA	0.8	437
6	TAS	0.9	435
7	NT	0.0	352

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

3.83 Application

This Division applies to fugitive emissions from venting or flaring from natural gas production 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; and

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

Subdivision 3.3.9A.1—Natural gas production—emissions that are vented—gas treatment processes

3.84 Available methods

(1) Subject to section 1.18, for estimating emissions relating to gas treatment processes (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85;

(ii) method 4 under Part 1.3.

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

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

3.85 Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas treatment processes

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1

Subdivision 3.3.9A.2—Natural gas production—emissions that are vented—cold process vents

3.85A Available methods

(1) Subject to section 1.18, for estimating emissions relating to cold process vents (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85B;

(ii) method 4 under Part 1.3.

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

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

3.85B Method 1—emissions from system upsets, accidents and deliberate releases from process vents

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Cold process vents	Section 5.3

Subdivision 3.3.9A.3—Natural gas production—emissions that are vented—natural gas blanketed tanks and condensate storage tanks

3.85C Available methods

(1) Subject to section 1.18, for estimating emissions relating to natural gas blanketed tanks and condensate storage tanks (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85D;

(ii) method 4 under Part 1.3.

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

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

3.85D Method 1—emissions from system upsets, accidents and deliberate releases from process vents—natural gas blanketed tanks and condensate storage tanks

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Natural gas blanketed tanks	Section 5.4.4
2	Condensate storage tanks	Section 5.4.1

Subdivision 3.3.9A.4—Natural gas production—emissions that are vented—gas driven pneumatic devices

3.85E Available methods

(1) Subject to section 1.18, for estimating emissions relating to gas driven pneumatic devices (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85F;

(ii) method 4 under Part 1.3.

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

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

3.85F Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas driven pneumatic devices

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Other venting sources—gas driven pneumatic devices	Section 5.6.1

Subdivision 3.3.9A.5—Natural gas production—emissions that are vented—gas driven chemical injection pumps

3.85G Available methods

(1) Subject to section 1.18, for estimating emissions relating to gas driven chemical injection pumps (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85H;

(ii) method 4 under Part 1.3.

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

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

3.85H Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas driven chemical injection pumps

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Other venting sources—gas driven chemical injection pumps	Section 5.6.2

Subdivision 3.3.9A.6—Natural gas production—emissions that are vented—well blowouts

3.85K Available methods

(1) Subject to section 1.18, for estimating emissions relating to well blowouts (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85L;

(ii) method 4 under Part 1.3.

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

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

3.85L Method 1—emissions from system upsets, accidents and deliberate releases from process vents—production related non-routine emissions—well blowouts

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Non-routine activities—production related non-routine emissions	Section 5.7.1

Subdivision 3.3.9A.7—Natural gas production—emissions that are vented—CO_2 stimulation

3.85M Available methods

(1) Subject to section 1.18, for estimating emissions relating to CO_2 stimulation (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85N;

(ii) method 4 under Part 1.3.

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

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

3.85N Method 1—emissions from system upsets, accidents and deliberate releases from process vents—production related non-routine emissions—CO_2 stimulation

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Non-routine activities—production related non-routine emissions	Section 5.7.1

Subdivision 3.3.9A.8—Natural gas production—emissions that are vented—well workovers

3.85O Available methods

(1) Subject to section 1.18, for estimating emissions relating to well workovers (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85P;

(ii) method 4 under Section 3.85Q.

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

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

3.85P Method 1—vented emissions from well workovers

(1) Subject to subsection (3), Method 1 is:

$$E_{ij} = \Sigma_k \; (Q_{ik} \times EF_{ijk} \times S_{ij} / SD_{ij})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive (vented) emissions of gas type (***j***), being methane or carbon dioxide, from the natural gas production during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the total emissions of gas type (***j***), being methane or carbon dioxide, 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 natural gas production.

$\boldsymbol{Q_{ik}}$ is the total of the number of well workover events for equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas production.

$\boldsymbol{EF_{ijk}}$ is the emission factor for gas type (***j***), being methane or carbon dioxide, measured in tonnes of CO_2-e per well workover event using equipment type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the natural gas production.

$\boldsymbol{S_{ij}}$ is the measured share of gas type (***j***), being methane or carbon dioxide, in the unprocessed gas (***i***), by volume, measured in accordance with Division 2.3.3 and the principles in section 1.13.

$\boldsymbol{SD_{ij}}$ is the default share of gas type (***j***) in the unprocessed gas (***i***), for methane SD is 0.825 and for carbon dioxide SD is 0.0345.

(2) For $\boldsymbol{EF_{ijk}}$ mentioned in subsection (1), column 3 of an item in the following table specifies the emission factor for methane for an equipment of type (***k***) specified

in column 2 of that item and column 4 of an item in the following table specifies the emission factor for carbon dioxide for an equipment of type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for gas type (j)		
		CH_4	CO_2	
1	Well workover without hydraulic fracturing	5.5	1.1×10^{-2}	tonnes CO_2-e per well workover event
2	Well workover with hydraulic fracturing and venting (no flaring)	1031	4.2	tonnes CO_2-e per well workover event
3	Well workover with hydraulic fracturing with capture (no flaring)	90.8	0.37	tonnes CO_2-e per well workover event
4	Well workover with hydraulic fracturing with flaring	136.6	0.56	tonnes CO_2-e per well workover event

(3) If the well workover includes a well unloading, the fugitive (vented) emissions of gas type (***j***), being methane or carbon dioxide, for the well unloading must be calculated by applying section 5.7.1 of the API Compendium.

3.85Q Method 4—vented emissions from gas well workovers

Method 4 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Non-routine activities—production related non-routine emissions	Section 5.7.1

Subdivision 3.3.9A.9—Natural gas production—emissions that are vented—vessel blowdowns, compressor starts and compressor blowdowns

3.85R Available methods

(1) Subject to section 1.18, for estimating emissions relating to vessel blowdowns, compressor starts and compressor blowdowns (emissions that are vented) released during a year from the operation of a facility that is constituted by natural gas production the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.85S;

(ii) method 4 under Part 1.3.

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

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

3.85S Method 1—emissions from system upsets, accidents and deliberate releases from process vents—production related non-routine emissions—vessel blowdowns, compressor starts and compressor blowdowns

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Non-routine activities—production related non-routine emissions—vessel blowdowns	Section 5.7.1 and 5.7.2
2	Non-routine activities—production related non-routine emissions—compressor starts	Section 5.7.1 and 5.7.2
3	Non-routine activities—production related non-routine emissions—compressor blowdowns	Section 5.7.1 and 5.7.2

Subdivision 3.3.9A.10—Natural gas production (emissions that are flared)

3.85T Available methods

(1) For estimating emissions released from gas flared from natural gas production:

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

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

3.86 Method 1—gas flared from natural gas production

(1) Method 1 is:

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

where:

EE_{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 during the year.

Q_i is the quantity of fuel type (***i***) measured in tonnes of gas flared during the year.

Note: This quantity includes all of the fuel type, not just hydrocarbons within the fuel type.

EF_{ij} is the emission factor for gas type (***j***) measured in CO_2-e tonnes of emissions per tonne of gas flared in the natural gas production during the year as determined under subsection (2).

(2) For EF_{ij} mentioned in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for fuel type (***i***) specified in column 2 of that item.

Item	fuel type (i)	Emission factor of gas type (j) (tonnes CO_2-e/tonnes fuel flared)		
		CO_2	CH_4	N_2O
1	Gas	2.7	0.133	0.026
2	Crude oil and liquids	3.20	0.009	0.06

3.87 Method 2—gas flared from natural gas production

For subparagraph 3.85V(1)(a)(ii), method 2 is:

$$E_{ico_2} = Q_h \times EF_{hi} \times OF_i + QCO_2$$

where:

E_{iCO_2} is the fugitive emissions of CO_2 from fuel type (***i***) flared in the natural gas production during the year, measured in CO_2-e tonnes.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in the natural gas production during the year, measured in tonnes in accordance with Division 2.3.3.

EF_{hi} is the carbon dioxide emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in the natural gas production during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with Division 2.3.3.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

QCO_2 is the quantity of CO_2 within the fuel type (***i***) in the natural gas production and processing during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

3.87A Method 2A—natural gas production (flared methane or nitrous oxide emissions)

For subparagraphs 3.85V(1)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

EF_{hij} is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in natural gas production during the year, mentioned for the fuel type in the table in subsection 3.85(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

E_{ij} is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from natural gas production during the year, measured in CO_2-e tonnes.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in natural gas production during the year, measured in tonnes in accordance with Division 2.3.3.

3.88 Method 3—gas flared from natural gas production

For subparagraph 3.84V(1)(a)(iii), method 3 is the same as method 2 under section 3.86, but the emission factor (***EF_{ij}***) must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

Division 3.3.9B—Natural gas gathering and boosting (emissions that are vented or flared)

3.88A Application

This Division applies to fugitive emissions from venting or flaring from natural gas gathering and boosting, 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 gathering and boosting; and

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

Subdivision 3.3.9B.1—Natural gas gathering and boosting (emissions that are vented)

3.88B Available methods

(1) Subject to section 1.18, method 1 under section 3.88G must be used for estimating fugitive emissions from gas vented during natural gas gathering and boosting.

Note: There is no method 2, 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.

3.88C Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas gathering and boosting emissions

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	**Emission process**	**API Compendium section**
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—gas production related non-routine emissions – gas gathering pipeline blowdowns	Section 5.7.1 and 5.7.2
7	Condensate storage tanks	Section 5.4.1

Subdivision 3.3.9B.2—Natural gas gathering and boosting (emissions that are flared)

3.88D Available methods

(1) For estimating emissions released from gas flared from natural gas gathering and boosting:

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

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

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 3.86 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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

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

3.88E Application

This Division applies to fugitive emissions from venting or flaring from natural gas 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 processing; and

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

Subdivision 3.3.9C.1—Natural gas processing (emissions that are vented)

3.88F Available methods

(1) Subject to section 1.18, method 1 under section 3.88G must be used for estimating fugitive emissions from gas vented during natural gas processing.

Note: There is no method 2, 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.

3.88G Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas processing

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—gas processing related non-routine emissions	Section 5.7.1 and 5.7.3
7	Condensate storage tanks	Section 5.4.1

Subdivision 3.3.9C.2—Natural gas processing (emissions that are flared)

3.88H Available methods

(1) For estimating emissions released from gas flared from natural gas processing:

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

   (i) method 1 under section 3.86;

   (ii) method 2 under section 3.87;

   (iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

   (i) method 1 under section 3.86;

   (ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

   (i) method 1 under section 3.86;

   (ii) method 2A under section 3.87A.

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 3.86 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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

Division 3.3.9D—Natural gas transmission (emissions that are flared)

3.88I Application

This Division applies to fugitive emissions from venting or flaring from natural gas transmission activities, including emissions from the flaring of natural gas, waste gas and waste vapour streams at those facilities.

Note: Vented emissions from Natural gas transmission are estimated under Division 3.3.7.

3.88J Available methods

(1) For estimating emissions released from gas flared from natural gas transmission :

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

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

Note: The flaring of gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

Division 3.3.9E—Natural gas storage (emissions that are vented or flared)

3.88K Application

This Division applies to fugitive emissions from venting or flaring from natural gas storage, 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, waste gas and waste vapour streams at those facilities.

Subdivision 3.3.9E.1——Natural gas storage (emissions that are vented)

3.88L Available methods

(1) Subject to section 1.18, method 1 under section 3.88M must be used for estimating fugitive emissions from gas vented during natural gas storage.

Note: There is no method 2, 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.

3.88M Method 1—emissions from system upsets, accidents and deliberate releases from process vents—gas storage related non-routine emissions

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities—gas storage related non-routine emissions	Section 5.7.1 and 5.7.4 a
7	Condensate storage tanks	Section 5.4.1

a The emission factor at Table 5-26 ‘Gas storage station venting’ must be used for each instance of a natural gas storage station if emissions are estimated according to section 5.7.4.

Subdivision 3.3.9E.2—Natural gas storage (emissions that are flared)

3.88N Available methods

(1) For estimating emissions released from gas flared from natural gas storage:

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

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.86A.

Note: The flaring of gas from natural gas storage releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

Division 3.3.9F— Natural gas liquefaction, storage and transfer (emissions that are vented or flared)

3.88O Application

This Division applies to fugitive emissions from venting or flaring from natural gas liquefaction, storage and transfer 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 liquefaction, storage and transfer activities; and

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

Subdivision 3.3.9F.1—Natural gas liquefaction, storage and transfer (emissions that are vented)

3.88P Available methods

(1) Subject to section 1.18, method 1 under section 3.88Q must be used for estimating fugitive emissions from gas vented from natural gas liquefaction, storage and transfer (emissions that are vented) activities.

Note: There is no method 2, 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.

3.88Q Method 1—emissions from system upsets, accidents and deliberate releases from process vents— natural gas liquefaction, storage and transfer

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tanks	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Non-routine activities— natural gas liquefaction, storage and transfer related non-routine emissions	Section 5.7.1 and 5.7.4 a
7	Condensate storage tanks	Section 5.4.1

a The emission factor at Table 5-26 ‘Gas storage station venting’ must be used for each instance of an LNG station if emissions are estimated according to section 5.7.4.

Subdivision 3.3.9F.2—Natural gas liquefaction, storage and transfer (emissions that are flared)

3.88R Available methods

(1) For estimating emissions released from gas flared from natural gas liquefaction, storage and transfer:

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

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

Note: The flaring of gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

Division 3.3.9G—Natural gas distribution (emissions that are flared)

3.88S Application

This Division applies to fugitive emissions from flaring from natural gas distribution activities, including emissions from the flaring of natural gas, waste gas and waste vapour streams at those facilities.

3.88T Available methods

(1) For estimating emissions released from gas flared from natural gas distribution:

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

(i) method 1 under section 3.86;

(ii) method 2 under section 3.87;

(iii) method 3 under section 3.88; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.86;

(ii) method 2A under section 3.87A.

Note: The flaring of gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.86 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 and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

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

Division 3.4.2—Transport of greenhouse gases

Subdivision 3.4.2.1—Preliminary

3.89 Application

This Division applies to fugitive emissions from the transport of a greenhouse gas captured for permanent storage or captured for enhanced oil recovery.

Note: Section 1.19A defines when a greenhouse gas is captured for permanent storage.

Note: Section 1.8 defines enhanced oil recovery.

3.90 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 the transport of a greenhouse gas captured for permanent storage or for injection as part of enhanced oil recovery, the methods as set out in this section must be used.

Emissions from transport of a greenhouse gas involving transfer

(2) If the greenhouse gas is transferred to a relevant person for injection by the person in accordance with a licence, lease or approval mentioned in section 1.19A or an enhanced oil recovery authority, one of the following methods must be used for estimating fugitive emissions of the greenhouse gas that result from the transport of the greenhouse gas stream for that injection:

(a) method 1 under section 3.91 (which deals with injection);

(b) method 2 under section 3.77 (which deals with transport), applied in relation to the greenhouse gas as if it were a type of natural gas.

Note 1: There is no method 3 or 4 for subsection (2).

Note 2: The same emissions cannot be counted under both the method mentioned in paragraph (2)(a) (injection) and the method mentioned in paragraph (2)(b) (transport).

Emissions from transport of a greenhouse gas not involving transfer

(2A) Subsection (3) applies if:

(a) the greenhouse gas is captured by a relevant person for injection in accordance with a licence, lease or approval mentioned in section 1.19A or an enhanced oil recovery authority; and

(b) the greenhouse gas is not transferred to another person for the purpose of injection.

(3) One of the following methods must be used for estimating fugitive emissions of the greenhouse gases that result from the transport of the greenhouse gas stream for that injection:

(a) method 1 under section 3.92 (which deals with injection);

(b) method 2 under section 3.77 (which deals with transport), applied in relation to the greenhouse gas as if it were a type of natural gas.

Note 1: There is no method 3 or 4 for subsection (3).

Note 2: The same emissions cannot be counted under both the method mentioned in paragraph (3)(a) (injection) and the method mentioned in paragraph (3)(b) (transport).

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

Subdivision 3.4.2.2—Emissions from transport of greenhouse gases involving transfer

3.91 Method 1—emissions from transport of greenhouse gases involving transfer

For subsection 3.90(2), method 1 is:

$$E_j = \gamma_j \left(RCCS_j - Q_{inj} \right) - E_{ij}$$

where:

$\boldsymbol{E_j}$ is the emissions of gas type (***j***), during the year from transportation of greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, to the storage or injection site, 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, being:

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

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

(c) for any other gas type—the appropriate conversion factor for the gas type.

$\boldsymbol{Q_{inj}}$ is the quantity of greenhouse gas injected into the storage or injection site during the year and measured in cubic metres at standard conditions of pressure and temperature.

$\boldsymbol{RCCS_j}$ is the quantity of gas type (***j***) captured during the year worked out under Division 1.2.3 and measured in cubic metres at standard conditions of pressure and temperature. If the injection is part of enhanced oil recovery, Division 1.2.3 must be applied to enhanced oil recovery as if it was capture for permanent storage.

$\boldsymbol{E_{ij}}$ is the fugitive emissions (***j***) from the injection of a greenhouse gas into a geological formation during the reporting year, measured in CO_2-e tonnes and calculated in accordance with Subdivision 3.4.3.2.

Subdivision 3.4.2.3—Emissions from transport of greenhouse gases not involving transfer

3.92 Method 1—emissions from transport of greenhouse gases not involving transfer

For subsection 3.90(3), method 1 is:

$$E_j = \gamma_j \left(RCCS_j - Q_{inj} \right)$$

where:

$\boldsymbol{E_j}$ is the emissions of gas type (***j***), during the year from transportation of greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, to the storage or injection site, measured in CO_2-e tonnes.

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

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

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

(c) for any other gas type—the appropriate conversion factor for the gas type.

Q_{inj} is the quantity of greenhouse gas injected into the storage or injection site during the year and measured in cubic metres at standard conditions of pressure and temperature.

$RCCS_j$ is the quantity of gas type (***j***) captured during the year worked out under Division 1.2.3 and measured in cubic metres at standard conditions of pressure and temperature. If the injection is part of enhanced oil recovery, Division 1.2.3 must be applied to enhanced oil recovery as if it was capture for permanent storage.

Division 3.4.3—Injection of greenhouse gases

Subdivision 3.4.3.1—Preliminary

3.93 Application

This Division applies to fugitive emissions of greenhouse gases from the injection of a greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, into a geological formation.

Note: A greenhouse gas is ***captured for permanent storage*** in a geological formation if the gas is captured by, or transferred to, the holder of a licence, lease or approval mentioned in section 1.19A, under a law mentioned in that section, for the purpose of being injected into a geological formation (however described) under the licence, lease or approval.

Note: Section 1.8 defines enhanced oil recovery.

3.94 Available methods

(1) For estimating fugitive emissions of greenhouse gases released during a year from the injection of a greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, into a geological formation, the methods set out in this section must be used.

Process vents, system upsets and accidents

(2) Method 2 under section 3.95 must be used for estimating fugitive emissions of greenhouse gases that result from deliberate releases from process vents, system upsets and accidents.

Fugitive emissions of greenhouse gases other than from process vents, system upsets and accidents

(3) One of the following methods must be used for estimating fugitive emissions of greenhouse gases from the injection of a greenhouse gas captured for permanent storage, or captured for enhanced oil recovery, into a geological formation that are not the result of deliberate releases from process vents, system upsets and accidents:

(a) method 2 under section 3.96;

(b) method 3 under section 3.97.

Note: There is no method 1, 3 or 4 for subsection (2) and no method 1 or 4 for subsection (3).

Subdivision 3.4.3.2—Fugitive emissions from deliberate releases from process vents, system upsets and accidents

3.95 Method 2—fugitive emissions from deliberate releases from process vents, system upsets and accidents

Method 2 is the same as the approach mentioned in section 5.3 or 5.7.1 of the API Compendium.

Subdivision 3.4.3.3—Fugitive emissions from injection of greenhouse gases (other than emissions from deliberate releases from process vents, system upsets and accidents)

3.96 Method 2—fugitive emissions from injection of a greenhouse gas into a geological formation (other than deliberate releases from process vents, system upsets and accidents)

(1) Method 2 is:

$$E_{ij} = \sum_k \left(Q_{ik} \times EF_{ijk} \right)$$

where:

EF_ijk is the emission factor (***j***) measured in CO_2-e tonnes that passes through each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

E_ij is the fugitive emissions (***j***) from the injection of a greenhouse gas into a geological formation during the reporting year, measured in CO_2-e tonnes.

Σ_k is the emissions (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

Q_ik is the total of the quantities of greenhouse gas measured in tonnes that pass through each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

(2) For ***EF_ijk*** in subsection (1), the emission factors are:

(a) the emission factors listed for the equipment type in section 6.1 of the API Compendium; or

(b) if the manufacturer of the equipment supplies equipment specific emissions factors for the equipment type—those factors.

3.97 Method 3—fugitive emissions from injection of greenhouse gases (other than deliberate releases from process vents, system upsets and accidents)

Method 3 is the same as an approach mentioned in Appendix C to the API Compendium.

Note: For this method, any approach mentioned in Appendix C to the API Compendium may be used.

4.12A Emissions—enhanced oil recovery

(1) This regulation applies if the operation of a facility of the corporation is an enhanced oil recovery source during a reporting year.

(2) The report must include the following information for the facility for the year:

(a) the amount of greenhouse gases captured for enhanced oil recovery;

(b) the amount of greenhouse gases imported for enhanced oil recovery;

(c) the amount of greenhouse gases injected at enhanced oil recovery sites.

(3) The report must include the following information about emissions from the operation of the facility during the year:

(a) the amount of emissions that occurred during the transportation of greenhouse gases to the enhanced oil recovery site;

(b) the amount of emissions that occurred when greenhouse gases were being injected into the enhanced oil recovery site;

(d) the type of the source of the emissions;

(e) the methods in the Measurement Determination used to estimate the emissions from the source;

(f) the total amount of greenhouse gases emitted from the source, in CO_2-e.

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Chapter 4—Industrial processes emissions

Part 4.1—Preliminary

4.1 Outline of Chapter

(2) (b)

(vii) hydrogen production (see Division 4.3.7);

Division 4.3.7—Hydrogen production

4.60 Application

This Division applies to chemical industry hydrogen production if:

(a) hydrogen is the main product at the facility; and

(b) the hydrogen is for use outside the facility; and

(c) the facility does not involve the production of ammonia with emissions reported under Division 4.3.1; and

(d) the emissions from hydrogen production are not included under another method in this Determination applicable to one or more primary products from the facility.

4.61 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 hydrogen:

(a) method 1 under section 4.62;

(b) method 2 under section 4.63;

(c) method 3 under section 4.64;

(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.

4.62 Method 1—hydrogen production

(1) Method 1 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000} - R$$

where:

***E**ij* is the emissions of carbon dioxide released from the production of hydrogen 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 hydrogen during the year, measured in the appropriate unit and estimated using a criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels.

Note: If more than one feedstock or type of fuel is used, the emissions of each feedstock or type of fuel are calculated and summed to determine the overall emissions.

EC_i is the energy content factor for fuel type ***(i)*** used as a feedstock in the production of hydrogen 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 hydrogen during the year, including the effects of oxidation, measured in kilograms for each gigajoule according to source as mentioned in Part 1 or 2 of Schedule 1.

R is the quantity of carbon dioxide measured in tonnes derived from the production of hydrogen during the year, captured and transferred for use in the operation of another facility, estimated using an applicable criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels and in accordance with any other requirements of those Divisions.

(2) For the purposes of calculating ***R*** in subsection (1), if:

(a) more than one fuel is consumed in the production of hydrogen; and

(b) the carbon dioxide generated from the production of hydrogen is captured and transferred for use in the operation of another facility or captured for permanent storage;

the total amount of carbon dioxide that may be deducted in relation to the production of hydrogen is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed in the production of hydrogen.

(3) However, if no fuel is used as a feedstock in the production of hydrogen the emissions of carbon dioxide released from the production of hydrogen during the year under this Division is taken to be zero.

Note: Hydrogen can be produced by electrolysis without using fossil fuels as a feedstock. Other emissions from the combustion of fuels at the facility may need to be reported elsewhere under this Determination.

4.62A Method 2—hydrogen production

(1) Method 2 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1\ 000} - R - \gamma RCCS_{co_2}$$

where:

E_{ij} is the emissions of carbon dioxide released from the production of hydrogen 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 hydrogen during the year, measured in the appropriate unit and estimated using an applicable criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels.

Note: If more than one feedstock or type of fuel is used, the emissions of each feedstock or type of fuel are calculated and summed to determine the overall emissions.

EC_i is the energy content factor for fuel type ***(i)*** used as a feedstock in the production of hydrogen 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 hydrogen during the year, including the effects of oxidation, measured in kilograms for each gigajoule according to source in accordance with subsection (2).

R is the quantity of carbon dioxide measured in tonnes derived from the production of hydrogen during the year, captured and transferred for use in the operation of another facility, estimated using an applicable criterion in Division 2.3.6 for gaseous fuels or Division 2.2.5 for solid fuels and in accordance with any other requirements of those Divisions.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) The method for estimating emission factors for gaseous fuels in Division 2.3.3, or for solid fuels in Division 2.2.3, apply for working out the factor EF_{ij}.

(3) For the purposes of calculating ***R*** in subsection (1), if:

(a) more than one fuel is consumed in the production of hydrogen; and

(b) the carbon dioxide generated from the production of hydrogen is captured and transferred for use in the operation of another facility or captured for permanent storage;

the total amount of carbon dioxide that may be deducted in relation to the production of hydrogen is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed in the production of hydrogen.

4.62B Method 3—hydrogen production

(1) Method 3 is the same as method 2 under section 4.62.

(2) In applying method 2 as method 3, the method for estimating emission factors for gaseous fuels in Division 2.3.4, or for solid fuels in Division 2.2.4, apply for working out the factor EF_{ij}.

Associated NGERS Regulation changes would be as follows:

Source 6—Hydrogen production

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the	(a) the tonnes of hydrogen produced from fossil fuel feedstocks (b) the tonnes of hydrogen produced from electrolysers

Item	Method	Matters to be identified
	Measurement Determination	(c) the amount of electricity consumed for hydrogen production from electrolysers (d) the tonnes of carbon dioxide recovered and transferred from the facility
2	Methods 2, 3 and 4 for the source, as set out in the Measurement Determination	(a) the tonnes of hydrogen produced from fossil fuel feedstocks (b) the tonnes of hydrogen produced from electrolysers (c) the amount of electricity consumed for hydrogen production from electrolysers (d) the tonnes of carbon dioxide recovered and transferred from the facility

Part 8.3—How to assess uncertainty when using method 1

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 (3) 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 (%)
	…		
33	Crude oil	6	3
34	Plant condensate and other natural gas liquids not covered by another item in this table	7	9

Schedule 1—Energy content factors and emission factors

Part 3—Fuel combustion—liquid fuels and certain petroleum-based products for stationary energy purposes

Item	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
	…				
33	Crude oil	45.3 GJ/t	69.6	0.1	0.2
34	Plant condensate and other natural gas liquids not covered by another item in this table	46.5 GJ/t	61.0	0.1	0.2

Schedule 3—Carbon content factors

Part 3—Liquid fuels and certain petroleum-based products

Item	Fuel type	Carbon content factor (tC/kL of fuel unless otherwise specified)
...		
Petroleum based products other than petroleum based oils and petroleum based greases		
33	Crude oil	0.861 tC/t fuel
34	Plant condensate and other natural gas liquids not covered by another item in this table	0.774 tC/t fuel

Matters to be identified—currently Part 2 of Schedule 3 to the Regulations

For all flaring oil and gas emissions sources, the following matters to be identified would be specified

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	(a) the tonnes of flared gas (b) the tonnes of flared crude oil and liquids
2	Methods 2, 2A and 3 for the source, as set out in the Measurement Determination	(a) the tonnes and megajoules of flared gas (hydrocarbon component) (b) the tonnes and megajoules of flared crude oil and liquids (hydrocarbon component)

Other oil and gas emissions sources would have the following matters to be identified

Oil or gas exploration and development—vents

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	(a) the tonnes and megajoules of vented gas for each gas type (b) number of well completions of each type
	Method 4	(a) the tonnes and megajoules of vented gas for each gas type

Crude oil production—leaks

Item	Method	Matters to be identified
1	Methods 1 and 2 for the source, as set out in the Measurement Determination	(a) the tonnes of crude oil throughput
2	Method 3 for the source, as set out in the Measurement Determination	(a) the tonnes of crude oil throughput (b) number of components of each component type (c) average hours of operation of each component type (d) total emissions of each gas type from each component type

Crude oil production—vents

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	(a) the tonnes and megajoules of vented gas for each gas type (b) number workovers of each event type
	Method 4 for the source, as set out in the Measurement Determination	(a) the tonnes and megajoules of vented gas for each gas type

Crude oil transport

Item	Method	Matters to be identified
1	Methods 1 and 2 for the source, as set out in the Measurement Determination	the tonnes of indigenous crude oil transported to Australian refineries

Crude oil refining—Refining and storage tanks

Item	Method	Matters to be identified
1	Methods 1, 2, and 3 for the source, as set out in the Measurement Determination	(a) the tonnes of crude oil refined (b) the tonnes of crude oil stored

Crude oil refining—Vents

Item	Method	Matters to be identified
1	Method 4 for the source, as set out in the Measurement Determination	(a) the quantity of refinery coke burnt

Onshore gas production (wellheads)—leaks

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	(a) the tonnes of onshore natural gas production throughput (b) the total number of wells (including producing wells and suspended wells but not decommissioned wells)
2	Method 2 for the source, as set out in the Measurement Determination	(a) the tonnes of onshore natural gas production throughput (b) number of equipment units of each equipment type (c) average hours of operation of each equipment type

Item	Method	Matters to be identified
		(d) total emissions for each gas type (CO2-e) for each equipment type
3	Method 3 for the source, as set out in the Measurement Determination	(a) the tonnes of onshore natural gas production throughput (b) the total number of wells (including producing wells and suspended wells but not decommissioned wells) (c) number of components of each component type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO2-e) for each component type (by leaker or non-leaker if LDAR factors are elected)

Offshore gas production—leaks

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	(a) the tonnes of offshore natural gas production throughput (b) the total number of offshore platforms (shallow water) (c) the total number of offshore platforms (deep water)
2	Method 2 for the source, as set out in the Measurement Determination	(a) the tonnes of offshore natural gas production throughput (b) the total number of offshore platforms (shallow water) (c) the total number of offshore platforms (deep water) (d) number of equipment units of each equipment type (e) average hours of operation of each equipment type (f) total emissions for each gas type (CO2-e) for each equipment type
3	Method 3 for the source, as set out in the Measurement Determination	(a) the tonnes of offshore natural gas production throughput (b) the total number of offshore platforms (shallow water) (c) the total number of offshore platforms (deep water) (d) number of components of each component type (by leaker or non-leaker if LDAR factors are elected) (e) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (f) total emissions for each gas type (CO2-e) for each component type (by leaker or non-leaker if LDAR factors are elected)

Gathering and boosting—leaks

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	(a) number of natural gas gathering and boosting stations (b) the tonnes of natural gas gathering and boosting throughput for each station (c) kilometres of pipeline length
2	Method 2 for the source, as set out in the Measurement Determination	Stations: (a) number of natural gas gathering and boosting stations (b) the tonnes of natural gas gathering and boosting throughput for each station (c) number of equipment units of each equipment type (d) average hours of operation of each equipment type (e) total emissions for each gas type (CO2-e) for each equipment type Pipelines: (f) kilometres of pipeline length of each material (g) total emissions for each gas type (CO2-e) for each material
3	Method 3 for the source, as set out in the Measurement Determination	Stations: (a) number of natural gas gathering and boosting stations (b) the tonnes of natural gas gathering and boosting throughput for each station (c) number of components of each type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type(by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO2-e) for each component type (by leaker or non-leaker if LDAR factors are elected) Pipelines: (f) kilometres of pipeline length of each material (g) total emissions for each gas type (CO2-e) for each material

Produced water

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	megalitres of produced water
2	Method 2 for the source, as set out in the Measurement Determination	(a) megalitres of produced water (b) average pressure in kilopascals for a water stream entering the separator during the year (c) average salinity content of the water

Gas processing—leaks

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	(a) number of processing stations (b) the tonnes of throughput for each station
2	Method 2 for the source, as set out in the Measurement Determination	(a) number of processing stations (b) the tonnes of throughput for each station (c) number of equipment units of each equipment type (d) average hours of operation of each equipment type (e) total emissions for each gas type (CO2-e) for each equipment type
3	Method 3 for the source, as set out in the Measurement Determination	(a) number of processing stations (b) the tonnes of throughput for each station (c) number of components of each type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type(by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO2-e) for each component type (by leaker or non-leaker if LDAR factors are elected)

Gas transmission—leaks

Item	Method	Matters to be identified
1	Method 1, 2 and 3 for the source, as set out in the Measurement Determination	(a) the terajoules of natural gas transmission throughput (b) kilometres of pipeline length

Gas storage—leaks

Item	Method	Matters to be identified
1	Method 1 for the source, as set out in the Measurement Determination	number of storage stations
2	Method 2 for the source, as set out in the Measurement Determination	(a) number of storage stations (b) number of equipment units of each equipment type (c) average hours of operation of each equipment type (d) total emissions for each gas type (CO2-e) for each equipment type
3	Method 3 for the source, as set out in the Measurement Determination	(a) number of storage stations (b) number of components of each type (by leaker or non-leaker if LDAR factors are elected)

Item	Method	Matters to be identified
		(c) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (d) total emissions for each gas type (CO2-e) for each component type (by leaker or non-leaker if LDAR factors are elected)

Gas liquefaction, storage and transfer—leaks

Item	Method	Matters to be identified
1	Method 1, and2 for the source, as set out in the Measurement Determination	(a) the tonnes of natural gas liquefied (b) number of liquefied natural gas stations
3	Method 3 for the source, as set out in the Measurement Determination	(a) the tonnes of natural gas liquefied (b) number of liquefied natural gas stations (c) number of components of each type (by leaker or non-leaker if LDAR factors are elected) (d) average hours of operation of each component type (by leaker or non-leaker if LDAR factors are elected) (e) total emissions for each gas type (CO2-e) for each component type (by leaker or non-leaker if LDAR factors are elected)

Gas distribution—leaks

Item	Method	Matters to be identified
1	Methods 1 and 2 for the source, as set out in the Measurement Determination	(a) terajoules of utility sales (b) location of the natural gas distribution
3	Method 3 for the source, as set out in the Measurement Determination	(a) terajoules of utility sales (b) location of the natural gas distribution (c) the facility specific unaccounted for gas factor as a percentage (d) whether the facility specific unaccounted for gas factor is the percentage calculated or determined for the reporting year or for a previous period

Gas production—vents

Item	Method	Matters to be identified
1	Methods 1 and 4 for the source, as set out in the	(a) the tonnes and megajoules of vented gas related to gas treatment processes

Item	Method	Matters to be identified
	Measurement Determination	(b) the tonnes and megajoules of vented gas related to cold process vents (c) the tonnes and megajoules of vented gas related to gas blanketed tanks (d) the tonnes and megajoules of vented gas related to condensate storage tanks (e) the tonnes and megajoules of vented gas related to gas driven pneumatic devices (f) the tonnes and megajoules of vented gas related to gas driven chemical injection pumps (g) the tonnes and megajoules of vented gas related to well blowouts (h) the tonnes and megajoules of vented gas related to carbon dioxide stimulation (i) the tonnes and megajoules of vented gas related to well workovers (j) the tonnes and megajoules of vented gas related to vessel blowdowns, compressor starts and compressor blowdowns (k) number of well workovers without hydraulic fracturing (l) number of well workovers with hydraulic fracturing and venting (no flaring) (m) number of well workovers with hydraulic fracturing with capture (no flaring) (n) number of well workovers with hydraulic fracturing with flaring

Natural gas gathering and boosting—venting

Natural gas processing—venting

Natural gas storage—venting

Natural gas liquefaction, storage and transfer—venting

Item	Method	Matters to be identified
1	Methods 1 and 4 for the source, as set out in the Measurement Determination	(a) the tonnes and megajoules of vented gas for each gas type

This would be separately listed for each of the above sources.