CHAPTER 4

FUGITIVE EMISSIONS

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4 FUGITIVE EMISSIONS

4.1 FUGITIVE EMISSIONS FROM MINING, PROCESSING, STORAGE AND TRANSPORTATION OF COAL

This section is an elaboration of Section 4.1, Vol. 2 of the *2006 IPCC Guidelines*.

Intentional or unintentional release of greenhouse gases may occur during the extraction, processing and delivery of fossil fuels to the point of final use. These are known as fugitive emissions.

4.1.1 Overview and description of sources

ELABORATED TO INCLUDE DESCRIPTION OF NEW COAL EXPLORATION SOURCE

Fugitive emissions associated with coal can be considered in terms of the following broad categories.[1]

4.1.1.1 COAL MINING AND HANDLING

The geological processes of coal formation also produce methane (CH_4), and carbon dioxide (CO_2) may also be present in some coal seams. These are known collectively as seam gas, and remain trapped in the coal seam until the coal is exposed and broken during mining. CH_4 is the major greenhouse gas emitted from coal mining and handling.

The major stages for the emission of greenhouse gases for both underground and surface coal mines are:

- **Mining emissions** – These emissions result from the liberation of stored gas during the breakage of coal, and the surrounding strata, during mining operations.
- **Post-mining emissions** – Not all gas is released from coal during the process of coal breakage during mining. Emissions, during subsequent handling, processing and transportation of coal are termed post-mining emissions. Therefore coal normally continues to emit gas *even after it has been mined*, although more slowly than during the coal breakage stage.
- **Low temperature oxidation** - These emissions arise because once coal is exposed to oxygen in air, the coal oxidizes to produce CO_2. However, the rate of formation of CO_2 by this process is low.
- **Uncontrolled combustion** – On occasions, when the heat produced by low temperature oxidation is trapped, the temperature rises and an active fire may result. This is commonly known as uncontrolled combustion and is the most extreme manifestation of oxidation. Uncontrolled combustion is characterised by rapid reactions, sometimes visible flames and rapid CO_2 formation, and may be natural or anthropogenic. It is noted that uncontrolled combustion only due to coal exploitation activities is considered here.
- **Exploration emissions –** These emissions result from boreholes drilled through carbonaceous strata for the purposes of coal exploration. This is distinct from gas drainage boreholes which form part of a degasification system, which are included for under Mining Emissions.

After mining has ceased, **abandoned coal mines** may also continue to emit methane.

A brief description of some of the major processes that need to be accounted for in estimating emissions for the different types of coal mines follows:

UNDERGROUND MINES

Active Underground Coal Mines

The following *potential* source categories for fugitive emissions for active underground coal mines are considered in this document:

[1] Methods for determining emissions from *peat extraction* are described in Volume 4 AFOLU Chapter 7 'Wetlands'.

Seam gas emissions vented to the atmosphere from coal mine *ventilation air* and *degasification systems*

- Post-mining emissions
- Low temperature oxidation
- Uncontrolled combustion

Coal mine ventilation air and degasification systems arise as follows:

Coal Mine Ventilation Air

Underground coal mines are normally ventilated by flushing air from the surface, through the underground tunnels in order to maintain a safe atmosphere. Ventilation air picks up the CH_4 and CO_2 released from the coal formations and transports these to the surface where they are emitted to atmosphere. The concentration of methane in the ventilation air is normally low, but the volume flow rate of ventilation air is normally large and therefore the methane emissions from this source can be very significant.

Coal Mine Degasification Systems

Degasification systems comprise wells drilled before, during, and after mining to drain gas (mainly CH_4) from the coal seams that release gas into the mine workings. During active mining the major purpose of degasification is to maintain a safe working atmosphere for the coal miners, although the recovered gas may also be utilised as an energy source. Degasification systems can also be used at abandoned underground coal mines to recover methane. The amount of methane recovered from coal mine degasification systems can be very significant and is accounted for, depending on its final use, as described in Section 4.1.3.2 of this chapter.

Abandoned Underground Mines

After closure, coal mines that were significant methane emitters during mining operations continue to emit methane unless there is flooding that cuts off the emissions. Even if the mines have been sealed, methane may still be emitted to the atmosphere as a result of gas migrating through natural or manmade conduits such as old portals, vent pipes, or cracks and fissures in the overlying strata. Emissions quickly decline until they reach a near-steady rate that may persist for an extended period of time.

Abandoned mines may flood as a result of intrusion of groundwater or surface water into the mine void. These mines typically continue to emit gas for a few years before the mine becomes completely flooded and the water prevents further methane release to the atmosphere. Emissions from completely flooded abandoned mines can be treated as negligible. Mines that remain partially flooded can continue to produce methane emissions over a long period of time, as with mines that do not flood.

A further potential source of emissions occurs when some of the coal from abandoned mines ignites through the mechanism of uncontrolled combustion. However, there are currently no methodologies for estimating potential emissions from uncontrolled combustion at abandoned underground mines.

SURFACE COAL MINES

Active Surface Mines

The *potential* source categories for surface mining considered in this chapter are:

- Methane and CO_2 emitted during mining from breakage of coal and associated strata and leakage from the pit floor and highwall
- Post-mining emissions
- Low temperature oxidation
- Uncontrolled combustion in waste dumps

Emissions from surface coal mining occur because the mined and surrounding seams may also contain methane and CO_2. Although the gas contents are generally less than for deeper underground coal seams, the emission of seam gas from surface mines needs to be taken into account, particularly for countries where this mining method is widely practised. In addition to seam gas emissions, the waste coal that is dumped into overburden or reject dumps may generate CO_2, either by low temperature oxidation or by uncontrolled combustion.

Abandoned Surface Mines

After closure, abandoned or decommissioned surface mines may continue to emit methane as the gas leaks from the coal seams that were broken or damaged during mining. There are at present no methods for estimating emissions from this source.

COAL EXPLORATION

This source category is concerned with emissions arising from boreholes drilled for coal mining exploration purposes. It does not include coal gas drainage wells used to collect gas prior or as a part of coal mining activities. Fugitive emissions from these sources are already counted in Underground and Surface Mining Activities. Gas drainage or production boreholes that may also include an exploration aspect are not to be counted as coal exploration boreholes.

The overall coal exploration process involves drilling of vertical boreholes from surface of the Earth to find out presence of coal seams, their depth of occurrence, thickness and other geological structures, resource and chemical characteristics such as ash, moisture, volatile matter (VM) and fixed carbon (FC). A small fraction of the methane gas retained by the coal seams may be released during borehole drilling and escape to the atmosphere. Emissions will occur only if the borehole drilling penetrates some gas bearing strata such as coal and carbonaceous shale.

Boreholes and wells associated with coal gas drainage and coal bed methane/natural exploration are concerned with gas flow, and gas bearing strata are often stimulated to increase gas flow. Coal exploration boreholes are focused on obtaining core samples or understanding strata geophysics, and therefore the coal fracture systems are not artificially stimulated. Thus, the gas flow from coal exploration boreholes and coal bed methane/natural gas boreholes are not comparable.

4.1.1.2 SUMMARY OF SOURCES

The major sources are summarised in Table 4.1.1 below.

TABLE 4.1.1 (ELABORATION)
DETAILED SECTOR SPLIT FOR EMISSIONS FROM MINING, PROCESSING, STORAGE AND TRANSPORT OF COAL

IPCC code	Sector name	
1 B	Fugitive emissions from fuels	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of fuel to the point of final use.
1 B 1	*Solid Fuels*	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of solid fuel to the point of final use.
1B a	Coal mining and handling	Includes all fugitive emissions from coal
1B 1 a i	*Underground mines*	Includes all emissions arising from mining, post-mining, abandoned mines and flaring of drained methane.
1 B 1 a i 1	*Mining*	Includes all seam gas emissions vented to atmosphere from coal mine ventilation air and degasification systems.
1 B 1 a i 2	*Post-mining seam gas emissions*	Includes methane and CO_2 emitted after coal has been mined, brought to the surface and subsequently processed, stored and transported.
1 B 1 a i.3	*Abandoned underground mines*	Includes methane emissions from abandoned underground mines
1 B 1 a i. 4	*Flaring of drained methane or conversion of methane to CO_2*	Methane drained and flared, or ventilation gas converted to CO_2 by an oxidation process should be included here. Methane used for energy production should be included in Volume 2, Energy, Chapter 2 ‘Stationary Combustion’.
1 B 1 a ii	*Surface mines*	Includes all seam gas emissions arising from surface coal mining
1 B 1 a.ii 1	*Mining*	Includes methane and CO_2 emitted during mining from breakage of coal and associated

		strata and leakage from the pit floor and highwall
1 B 1 a.ii. 2	*Post-mining seam gas emissions*	Includes methane and CO_2 emitted after coal has been mined, subsequently processed, stored and transported.
1 B 1 a iii	*Coal exploration*	Includes methane emissions from boreholes drilled for the purposes of coal exploration.
1 B 1 b	*Uncontrolled combustion and burning coal dumps*	Includes emissions of CO_2 from uncontrolled combustion due to coal exploitation activities.

4.1.2 Methodological issues

The following sections focus on methane emissions, as this gas is the most important fugitive emission for coal mining. Methods for estimating carbon dioxide emissions from underground and surface mining are also provided. Carbon dioxide emissions from other coal mining sources should also be included in the inventory where data are available.

UNDERGROUND MINING

Fugitive emissions from underground mining arise from both ventilation and degasification systems. These emissions are normally emitted at a small number of centralised locations and can be considered as point sources. They are amenable to standard measurement methods.

SURFACE MINING

For surface mining the emissions of greenhouse gases are generally dispersed over sections of the mine and are best considered area sources. These emissions may be the result of seam gases emitted through the processes of breakage of the coal and overburden, low temperature oxidation of waste coal or low quality coal in dumps, and uncontrolled combustion. Measurement methods for low temperature oxidation and uncontrolled combustion are still being developed and therefore estimation methods are not included in this chapter.

ABANDONED MINES

Abandoned underground mines present difficulties in estimating emissions, although a methodology for abandoned underground mines is included in this chapter. Methodologies do not yet exist for abandoned or decommissioned surface mines, and therefore they are not included in this chapter.

EXPLORATION

Large fraction of the gas contained in the coal seams is adsorbed on the coal surface inside the micropores and a small fraction in the free state in the macro pores and cleats. The hydrostatic pressure that a coal seam is subjected to prevents desorption of the gas from coal matrix. Gas flow from exploration boreholes is not comparable to the flow of gas in coalbed methane wells where the coal seams are stimulated by hydro fracturing and depressurized by dewatering the coal seams. Emission during exploratory borehole drilling may be largely associated to the amount of coal or lignite augmented during the period.

METHANE RECOVERY AND UTILISATION

Methane recovered from drainage, ventilation air, or abandoned mines may be mitigated in two ways: (1) direct utilization as a natural gas resource or (2) by flaring to produce CO_2, which has a lower greenhouse warming potential than methane.

TIERS

Use of appropriate tiers to develop emissions estimates for coal mining in accordance with good practice depends on the quality of data available. For instance, if limited data are available and the category is not key, then Tier 1 is *good practice*. The Tier 1 approach requires that countries choose from a global average range of emission factors and use country-specific activity data to calculate total emissions. Tier 1 is associated with the highest level of uncertainty. The Tier 2 approach uses country- or basin-specific emission factors that represent the average values for the coals being mined. These values are normally developed by each country, where appropriate. The Tier 3 approach uses direct measurements on a mine-specific basis and, properly applied, has the lowest level of uncertainty.

4.1.3 Underground coal mines

***ELABORATED TO ADD METHOD FOR ESTIMATING CARBON DIOXIDE EMISSIONS FROM UNDERGOUND MINES ***

The general form of the equation for estimating emissions for Tier 1 and 2 approaches, based on coal production activity data *from underground coal mining and post-mining emissions* is given by Equation 4.1.1 below. Methods to estimate emissions from *abandoned* underground mines, included in the guidelines for the first time, are described in detail in Section 4.1.5.

Equation 4.1.1 represents emissions before adjustment for any utilisation or flaring of recovered gas:

EQUATION 4.1.1
ESTIMATING EMISSIONS FROM UNDERGROUND COAL MINES FOR TIER 1 AND TIER 2 WITHOUT ADJUSTMENT FOR METHANE UTILISATION OR FLARING

Greenhouse gas emissions = Raw coal production● Emission Factor● Units conversion factor

The definition of the *Emission Factor* used in this equation depends on the activity data used. For Tier 1 and Tier 2, the *Emission Factor* for underground, surface and post-mining emissions has units of $m^3 tonne^{-1}$, the same units as in situ gas content. This is because these *Emission Factors* are used with activity data on raw coal production which has mass units (i.e. tonnes). However, the *Emission Factor* and th*e in situ* gas content are not the same and should not be confused. The *Emission Factor* is always larger than the *in situ* gas content, because the gas released during mining draws from a larger volume of coal and adjacent gas-bearing strata than simply the volume of coal produced. For *abandoned underground mines,* the *Emission Factor* has different units, because of the different methodologies employed, see section 4.1.5 for greater detail.

The equation to be used along with Equation 4.1.1 in order to adjust for methane utilisation and flaring for Tier 1 and Tier 2 approaches is shown in Equation 4.1.2.

EQUATION 4.1.2 (ELABORATION)
ESTIMATING EMISSIONS FROM UNDERGROUND COAL MINES FOR TIER 1 AND TIER 2 WITH ADJUSTMENT FOR METHANE UTILISATION OR FLARING

CH_4 emissions from underground mining activities = Emissions from underground mining CH_4 + Post-mining emission of CH_4 – CH_4 recovered and utilized for energy production or flared

CO_2 emissions from underground mining activities = Emissions from underground mining CO_2 - the amount of CO_2 contained in the gas recovered and utilized for energy production or flared

Emissions from underground mines in equations 4.1.1 and 4.1.2 include abandoned mines (see section 4.1.5) and both go into the total for 1.B. 1.a.i (Underground mines).

Equation 4.1.2 is used for Tiers 1 and 2 because they use *Emission Factors* to account for emissions from coal mines on a national or coal-basin level. The emission factors already include all the methane likely to be released from mining activities. Thus, any methane recovery and utilization must be explicitly accounted for by the subtraction term in Equation 4.1.2. Tier 3 methods involve mine-specific calculations which take into account the methane drained and recovered from individual mines rather than emission factors, and therefore Equation 4.1.2 is not appropriate for Tier 3 methods.

4.1.3.1 CHOICE OF METHOD

UNDERGROUND MINING

Figures 4.1.1 and 4.1.1a shows the methane and carbon dioxide decision trees for underground coal mining activities. For countries with underground mining, and where mine-specific measurement data are available it is *good practice* to use a Tier 3 method. Mine-specific data, based on ventilation air measurements and degasification system measurements, reflect actual emissions on a mine-by-mine basis, and therefore produce a more accurate estimate than using *Emission Factors.*

Hybrid Tier 3 - Tier 2 approaches are appropriate in situations when mine-specific measurement data are available only for a subset of underground mines. For example, if only mines that are considered gassy report data, emissions from the remaining mines can be calculated with Tier 2 emission factors. The definition of what constitutes a gassy mine will be determined by each country. For instance, in the United States, gassy mines refers to coal mines with average annual ventilation emissions exceeding the range of 2 800 to 14 000 cubic meters per day. Emission factors can be based on specific emission rates derived from Tier 3 data if the mines are operating within the same basin as the Tier 3 mines, or on the basis of mine-specific properties, such as the average depth of the coal mines.

When no mine-by-mine data are available, but country- or basin-specific data are, it *is good practice* to employ the Tier 2 method.

Where no data (or very limited data) are available, it is *good practice* to use a Tier 1 approach, provided underground coal mining is not a key sub source category. If it is, then it is *good practice* to obtain emissions data to increase the accuracy of these emissions estimates (see Figures 4.1.1 and Figures 4.1.1a).

POST-MINING

Direct measurement (Tier 3) of all post-mining emissions is not feasible, so an emission factor approach must be used. The Tier 2 and Tier 1 methods described below represent *good practice* for this source, given the difficulty of obtaining better data.

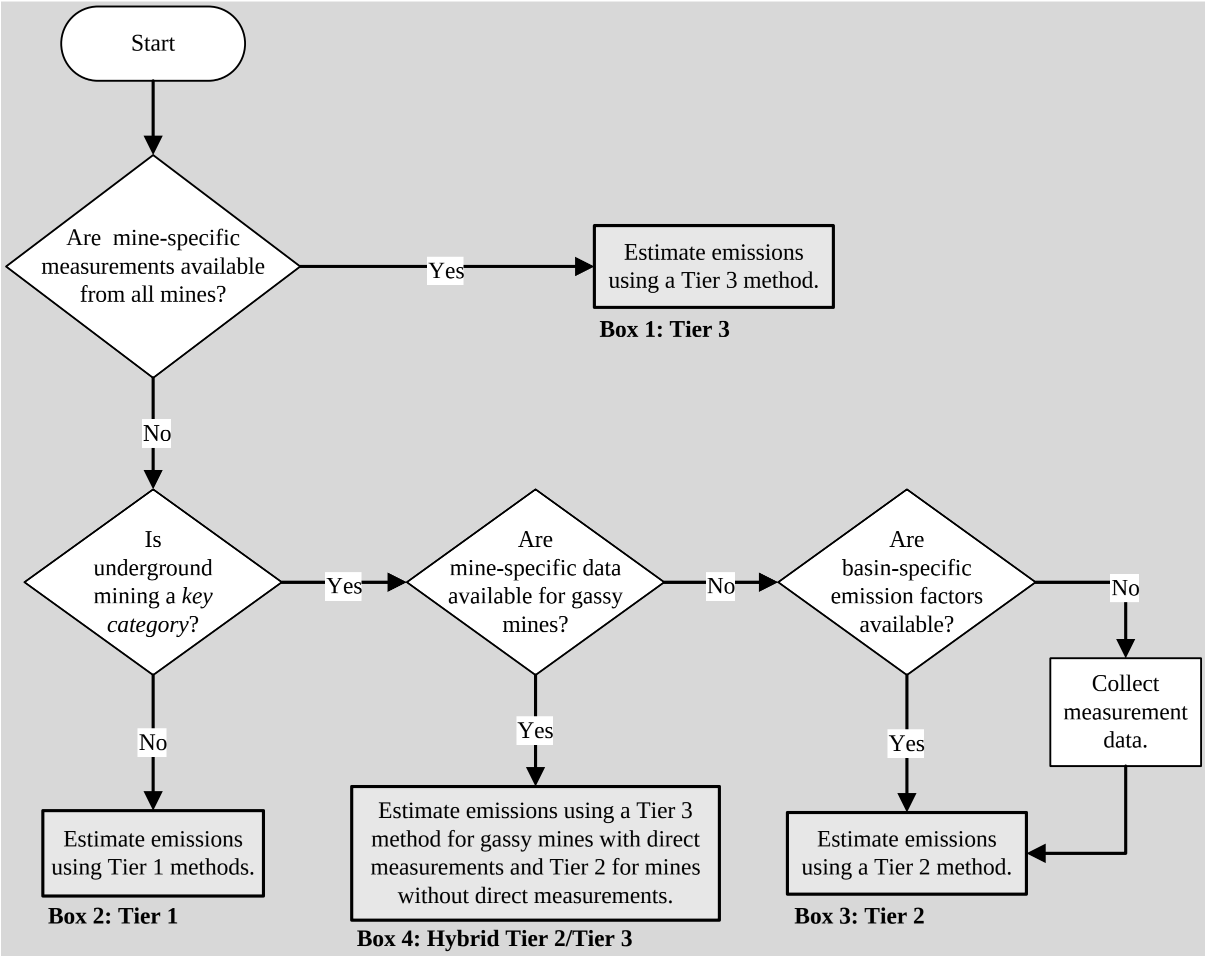
LOW TEMPERATURE OXIDATION

Oxidation of coal when it is exposed to the atmosphere by coal mining releases CO_2. This source will usually be insignificant when compared with the total emissions from gassy underground coal mines. Consequently, no methods are provided to estimate it.

ABANDONED UNDERGROUND MINES

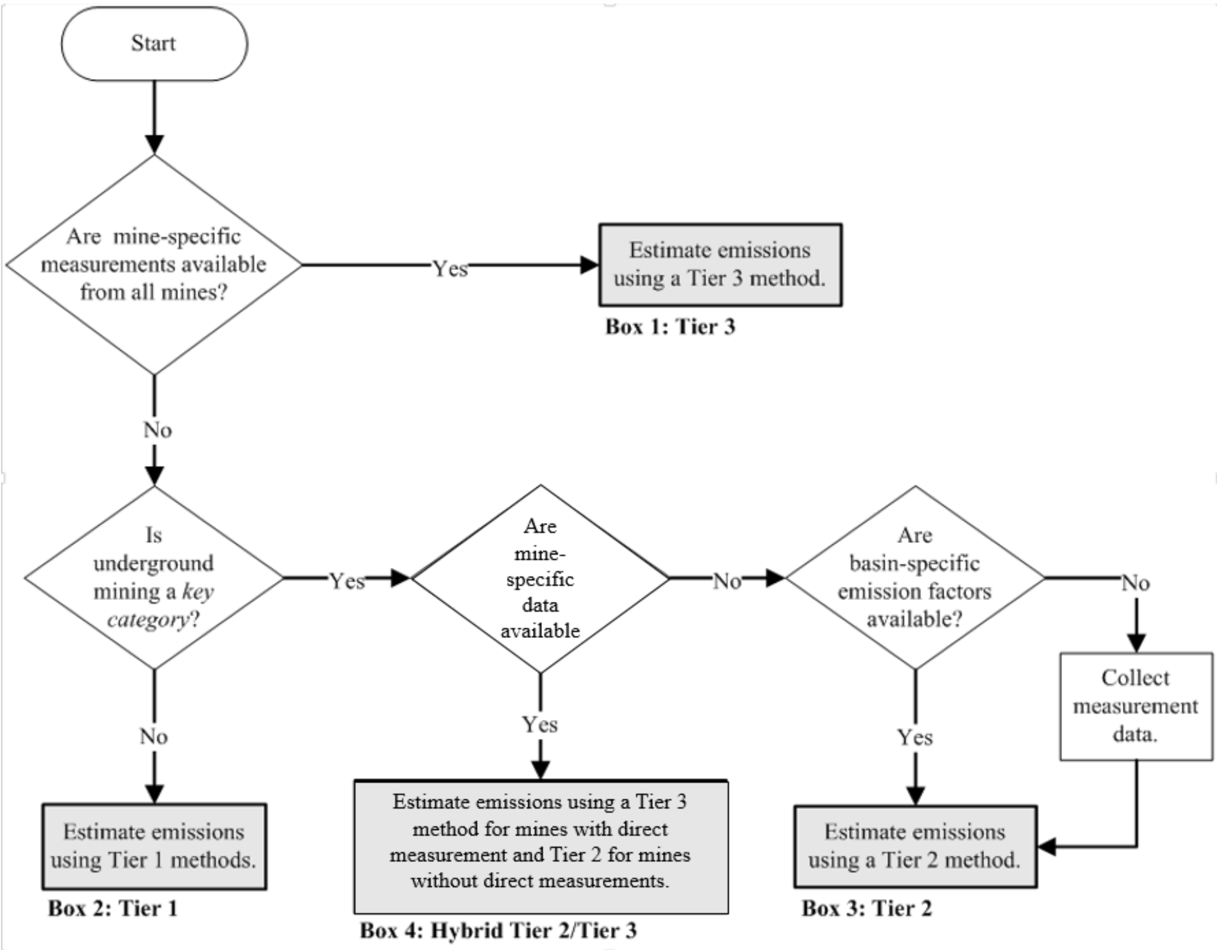
Fugitive methane emissions from abandoned underground mines should be reported in Underground Mines in IPCC Category 1.B.1.a.i.3, using the methodology presented in Section in 4.1.5.

Figure 4.1.1 Decision tree for methane from underground coal mines



Note: See Volume 1 Chapter 4, "Methodological Choice and Key Categories" (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

Figure 4.1.1a Decision tree for carbon dioxide from underground coal mines



Note: See Volume 1 Chapter 4, "Methodological Choice and Key Categories" (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

4.1.3.2 CHOICE OF EMISSION FACTORS FOR UNDERGROUND MINES

MINING

Methane

Tier 1 Emission Factors for underground mining are shown below. The emission factors are the same as those described in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (BCTSRE, 1992; Bibler et al, 1991; Lama, 1992; Pilcher et al, 1991;USEPA, 1993a,b and Zimmermeyer, 1989).

EQUATION 4.1.3
TIER 1: GLOBAL AVERAGE METHOD – UNDERGROUND MINING – METHANE -BEFORE ADJUSTMENT FOR ANY METHANE UTILISATION OR FLARING

$$CH_4 \text{ emissions} = CH_4 \text{ Emission Factor} \bullet \text{Underground Coal Production} \bullet \text{Conversion Factor}$$

Where units are:

Methane Emissions (Gg year^{-1})

CH_4 Emission Factor (m^3 tonne^{-1})

Underground Coal Production (tonne year^{-1})

Emission Factor:

Low CH_4 Emission Factor = 10 m^3 tonne^{-1}

Average CH_4 Emission Factor =18 m^3 tonne^{-1}

High CH_4 Emission Factor = 25 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67 ● 10^{-6} Gg m^{-3}.

Countries using the Tier 1 approach should consider country-specific variables such as the depth of major coal seams to determine the emission factor to be used. As gas content of coal usually increases with depth, the low end of the range should be chosen for average mining depths of <200 m, and for depths of > 400 m the high value is appropriate. For intermediate depths, average values can be used.

For countries using a Tier 2 approach, basin-specific emission factors may be obtained from sample ventilation air data or from a quantitative relationship that accounts for the gas content of the coal seam and the surrounding strata affected by the mining process, along with raw coal production. For a typical longwall operation, the amount of gas released comes from the coal being extracted and from any other gas-bearing strata that are located within 150 m above and 50 m below the mined seam (*Good Practice Guidance*, 2000).

Carbon dioxide

Tier 1 Emission Factors for underground mining are shown below. The emission factors have been derived from National Inventory Reports, scientific literature, and data reported to national reporting programs, for the coal mining countries and regions; Australia, China, Czech Republic, India, Slovakia, Slovenia, Russia and Ukraine.

(Central Institute of Mining and Fuel Research, 2016; Commonwealth of Australia, 2017; Czech Republic, 2017; Moscow Geological Prospecting Institute, 1979, 1980; Republic of Slovenia, 2017; Slovak Republic, 2017)

EQUATION 4.1.3A

TIER 1: GLOBAL AVERAGE METHOD – UNDERGROUND MINING – CARBON DIOXIDE

CO_2 emissions = CO_2 Emission Factor ● Underground Coal Production ● Conversion Factor

Where units are:

Carbon dioxide Emissions (Gg $year^{-1}$)

CO_2 Emission Factor (m^3 $tonne^{-1}$)

Underground Coal Production (tonne $year^{-1}$)

Emission Factor:

Low CO_2 Emission Factor = 3.5 m^3 $tonne^{-1}$

Average CO_2 Emission Factor = 7.4 m^3 $tonne^{-1}$

High CO_2 Emission Factor = 12.3 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CO_2 and converts volume of CO_2 to mass of CO_2. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 1.839 ● 10^{-6} Gg m^{-3}(GOST, 2015).

Countries should use the average emission factor unless there is country-specific evidence to support use of an alternative factor within the low/high range. Countries may consider country-specific circumstances such as geological location/basis/depth to determine the emission factor to be used.

For countries using a Tier 2 approach, basin-specific emission factors may be obtained from analysis of ventilation air data. When assessing CO_2 gas volumes in mine ventilation systems, care needs to be taken to exclude CO_2 from non-fugitive sources such as;

- ambient carbon dioxide present in the air that was drawn into the mine ventilation intake - to take into account the atmospheric CO_2 constant of the air drawn into the intake of the ventilation system.
- fuel combustion CO_2 emissions arising from the use of machinery, while the machinery is in the underground mine.

POST-MINING EMISSIONS

For a Tier 1 approach the post-mining emissions factors are shown below together with the estimation method:

EQUATION 4.1.4
TIER 1: GLOBAL AVERAGE METHOD – POST-MINING EMISSIONS – UNDERGROUND MINES

Methane emissions = CH_4 Emission Factor ● Underground Coal Production ● Conversion Factor

Where units are:

Methane Emissions (Gg $year^{-1}$)

CH_4 Emission Factor (m^3 $tonne^{-1}$)

Underground Coal Production (tonne $year^{-1}$)

Emission Factor:

Low CH_4 Emission Factor	= 0.9 m^3 $tonne^{-1}$
Average CH_4 Emission Factor	=2.5 m^3 $tonne^{-1}$
High CH_4 Emission Factor	= 4.0 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67●10^{-6} Gg m^{-3}.

Tier 2 methods to estimate post-mining emissions take into account the *in situ* gas content of the coal. Measurements on coal as it emerges on a conveyor from an underground mine without degasification prior to mining indicate that 25-40 percent of the *in situ* gas remains in the coal (Williams and Saghafi, 1993). For mines that practice pre-drainage, the amount of gas in coal will be less than the *in situ* value by some unknown amount. For mines with no pre-drainage, but with knowledge of the *in situ* gas content, the post-mining emission factor can be set at 30 percent of the *in situ* gas content. For mines with pre-drainage, an emission factor of 10 percent of the *in situ* gas content is suggested.

Tier 3 methods are not regarded as feasible for post-mining operations.

EMISSIONS FROM DRAINED METHANE

Methane drained from working (or abandoned) underground (or surface) coal mines can be vented directly to the atmosphere, recovered and utilised, or converted to CO_2 through combustion (flaring or catalytic oxidation) without any utilisation. The manner of accounting for drained methane varies, depending on the final use of the methane.

In general:

- Tier 1 represents an aggregate emissions estimate using emission factors. In general, it is not expected that emissions associated with drained methane would be applicable for Tier 1. Presumably, if methane were being drained, there would be better data to enable use of Tier 2 or even Tier 3 methods to make emissions estimates. However, Tier 1 has been included in the discussion below, in case Tier 1 methods are being used to estimate national emissions where there are methane drainage operations.

- When methane is drained from coal seams as part of coal mining and subsequently flared or used as a fuel, it is *good practice* to subtract this amount from the total estimate of methane emissions for Tier 1 and Tier 2 (Equation 4.1.2). Data on the amount of methane that is flared or otherwise utilised should be obtained from mine operators with the same frequency of measurement as pertains to underground mine emissions generally.

- For Tiers 1 and 2, if methane is drained and vented to the atmosphere rather than utilized, it should not be re-counted as it already forms part of the emissions estimates for these approaches.

- For Tier 3, methane recovered from degasification systems and vented to the atmosphere prior to mining should be added to the amount of methane released through ventilation systems so that the total estimate is complete. In some cases, because degasification system data are considered confidential, it may be necessary to estimate degasification system collection efficiency, and then subtract known reductions to arrive at the net degasification system emissions.

- All methane emissions associated with coal seam degasification related to coal mining activities should be accounted for in the inventory year in which the emissions and recovery operations occur. Thus, the total emissions from all ventilation shafts and from all degasification operations that emit methane to the atmosphere are reported for each year, regardless of when the coal seam is mined through, as long as the emissions are associated with mining activities. This represents a departure from the previous guidelines where the drained methane was accounted for in the year in which the coal seam was mined through.

- When coal bed methane is extracted from coal seams for the purpose of gas mining for delivery into a natural gas system, then the fugitive emissions associated with the exploration, production, processing, transmission and storage are dealt with in the oil and natural gas source category (Section 4.2). Tier 1 fugitive emission factors for coal bed methane production are provided under 1B 2 b iii 2 Production and Gathering in Table 4.2.10.

When recovered methane is utilized as an energy source:

- Any emissions resulting from use of recovered coal mine methane as an energy source should be accounted for based on its final end-use, for example in the Energy Volume, Chapter 2, 'Stationary Combustion' when used for stationary energy production.
- Where recovered methane from coal seams is fed into a natural gas system and used as natural gas, the *fugitive* emissions occurring as part of those natural gas systems are dealt with in the oil and natural gas source category (Section 4.2).

When recovered methane is flared:

- When the methane is simply combusted with no useful energy, as in flaring or catalytic oxidation to CO_2, the corresponding CO_2 production should be added to the total greenhouse gas emissions (expressed as CO_2 equivalents) from coal mining activities. Such emissions should be accounted for as shown by Equation 4.1.5, below. Amounts of nitrous oxide and non-methane volatile organic compounds emitted during flaring will be small relative to the overall fugitive emissions and need not be estimated.

EQUATION 4.1.5

EMISSIONS OF CO_2 AND CH_4 FROM DRAINED METHANE FLARED OR CATALYTICALLY OXIDISED

(a)Emissions of CO_2 from CH_4 combustion = 0.98●Volume of methane flared ●Conversion Factor ● Stoichiometric Mass Factor

(a)Emissions of unburnt methane = 0.02 ● Volume of methane flared ● Conversion Factor

Where units are:

Emissions of CO_2 from methane combustion (Gg year^{-1})

Volume of methane oxidised (m^3 year^{-1})

Stoichiometric Mass Factor is the mass ratio of CO_2 produced from full combustion of unit mass of methane and is equal to 2.75

Note: 0.98 represents the combustion efficiency of natural gas that is flared (Compendium of Greenhouse gas Emission Methodologies for the Oil and gas Industry, American Petroleum Institute, 2004)

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67●10^{-6} Gg m^{-3}.

4.1.3.3 CHOICE OF ACTIVITY DATA

The activity data required for Tiers 1 and 2 are raw coal production. If the data on raw coal production are available these should be used directly. If coal is not sent to a coal preparation plant or washery for upgrading by removal of some of the mineral matter, then raw coal production equals the amount of saleable coal. Where coal is upgraded, some coal is rejected in the form of coarse discards containing high mineral matter and also in the form of unrecoverable fines. The amount of waste is typically around 20 percent of the weight of raw coal feed, but may vary considerably by country. Where activity data are in the form of saleable coal, an estimate should be made of the amount of production that is washed. Raw coal production is then estimated by increasing the amount of 'saleable coal' by the fraction lost through washing.

An alternative approach that may be more suitable for mines whose raw coal output contains rock from the roof or floor as a deliberate part of the extraction process, is to use saleable coal data in conjunction with emission factors referenced to the clean fraction of the coal, not raw coal. This should be noted in the inventory.

For the Tier 3 methods, coal production data are unnecessary because actual emissions measurements are available. However, it is *good practice* to collect and report these data to illustrate the relationship, if any, between underground coal production and actual emissions on an annual basis.

High quality measurements of methane drained by degasification systems should also be available from mine operators for mines where drainage is practised. If detailed data on drainage rates are absent, *good practice* is to obtain data on the efficiency of the systems (i.e. the fraction of gas drained) or to make an estimate using a range (e.g. 30-50 percent, typical of many degasification systems). If associated mines have data available these may also be used to provide guidance. Annual total gas production records for previous years should be maintained; these records may be available from appropriate agencies or from individual mines.

Where data on methane recovery from coal mines and utilisation are not directly available from mine operators, gas sales could be used as a proxy. If gas sales are unavailable, the alternative is to estimate the amount of utilised methane from the known efficiency specifications of the drainage system. Only methane that would have been emitted from coal mining activities should be considered as recovered and utilized. These emissions should be accounted for in Volume 2, Chapter 4, Section 4.2, 'Fugitive emissions from oil and natural gas', or if the emissions are combusted for energy, in Volume 2, Chapter 2 'Stationary Combustion'.

4.1.3.4 COMPLETENESS FOR UNDERGROUND COAL MINES

The estimate of emissions from underground mining should include:

- Drained gas produced from degasification systems
- Ventilation emissions
- Post-mining emissions
- Estimates of volume of methane recovered and utilized or flared
- Abandoned underground coal mines (see Section 4.1.5 for methodological guidance)

These sub sources categories are included in the current Guidelines.

4.1.3.5 DEVELOPING A CONSISTENT TIME SERIES

Comprehensive mine-by-mine (i.e. Tier 3) data may be available for some but not all years. If there have been no major changes in the number of active mines, emissions can be scaled to production for missing years, if any. If there were changes in the mine number, the mines involved can be removed from the scaling extrapolation and handled separately. However, care must be taken in scaling because the coal being mined, the virgin exposed coal and the disturbed mining zone each have different emission rates. Furthermore, mines may have a high background emission level that is independent of production.

The inventory guidelines recommend that methane emissions associated with coal seam degasification related to mining should be accounted for in the inventory year in which the emissions and recovery operations occur. This is a departure from previous guidelines which suggested that the methane emissions or reductions only be accounted for during the year in which the coal was produced (e.g. the degasification wells were "mined through.") Thus, if feasible, re-calculation of previous inventory years is desirable to make a consistent time series.

In cases where an inventory compiler moves from a Tier 1 or Tier 2 to a Tier 3 method, it may be necessary to calculate implied emissions factors for years with measurement data, and apply these emission factors to coal production for years in which these data do not exist. It is important to consider if the composition of the mine population has changed dramatically during the interim period, because this could introduce uncertainty. For mines that have been abandoned since 1990, data may not be archived if the company disappears. These mines should be treated separately when adjusting the time series for consistency.

For situations where the emissions of greenhouse gases from active underground mines have been well characterized and the mines have passed from being considered 'active' to 'abandoned', care should be taken so as not to introduce major discontinuities in the total emissions record from coal mining.

4.1.3.6 UNCERTAINTY ASSESSMENT

***ELABORATED TO ADD UNCERTAINTY ESTIMATES FOR UNDERGOUND MINING CARBON DIOXIDE EMISSION FACTORS ***

EMISSION FACTOR UNCERTAINTIES

Emission Factors for Tiers 1 and 2

The major sources of uncertainty for a Tier 1 approach arise from two sources. These are:

- The applicability of global emission factors to individual countries
- Inherent uncertainties in the emission factors themselves

The uncertainty due to the first point above is difficult to quantify, but could be significant. The inherent uncertainty in the emission factor is also difficult to quantify because of natural variability within the same coal region is known to occur.

For a Tier 2 approach, the same broad comments apply, although basin-specific data will reduce the inherent uncertainty in the Emission Factor compared with a Tier 1 approach. With regard to the inherent variability in the Emission Factor, 'Expert Judgement' in the *Good Practice Guidance (2000*) suggested that this was likely to be at least ±50 percent.

Table 4.1.2 shows the Tier 1 and Tier 2 uncertainties associated with emissions from underground coal mining. The uncertainties for these Tiers are based on expert judgement.

TABLE 4.1.2 (ELABORATION)
ESTIMATES OF UNCERTAINTY FOR UNDERGROUND MINING FOR TIER 1 AND TIER 2 APPROACHES

Likely uncertainties of coal mine methane Emission factors (Expert judgment - GPG, 2000*)		
Method	**Mining**	**Post-Mining**
Tier 2	± 50-75%	± 50%
Tier 1	Factor of 2 greater or smaller	Factor of 3 greater or smaller
*GPG, 2000 *IPCC Good Practice Guidance* and Uncertainty Management in National Greenhouse Gas Inventories (2000)		
Likely uncertainties of coal mine carbon dioxide emission factors *		
Method	**Mining**	**Post-Mining**
Tier 2	± 50-75%	Not applicable
Tier 1	Factor of 2 greater or smaller	Not applicable
*Uncertainties set to be consistent with methane emission factors given that measurement practices are likely to be similar		

Tier 3

Methane emissions from underground mines have a significant natural variability due to variations in the rate of mining and drainage of gas. For instance, the gas liberated by longwall mining can vary by a factor of up to two during the life of a longwall panel. Frequent measurements of underground mine emissions can account for such variability and also reduce the intrinsic errors in the measurement techniques. As emissions vary over the course of a year due to variations in coal production rate and associated drainage, *good practice* is to collect measurement data as frequently as practical, preferably biweekly or monthly to smooth out variations. Daily measurements would ensure a higher quality estimate. Continuous monitoring of emissions represents the highest stage of emission monitoring, and is implemented in some modern longwall mines.

Spot measurements of methane concentration in ventilation air are probably accurate to ±20 percent depending on the equipment used. Time series data or repeat measurements will significantly reduce the uncertainty of annual emissions to ±5 percent for continuous monitoring, and 10-15 percent for monitoring conducted every two weeks. Ventilation airflows are usually fairly accurately known (±2 percent). When combining the inaccuracies in emissions concentration measurements with the imprecision due to measurement and calculation of instantaneous measurements, overall emissions for an individual mine may be under-represented by as much as 10 percent or over-represented by as much as 30 percent (Mutmansky and Wang, 2000).

Spot measurement of methane concentration in drained gas (from degasification systems) is likely to be accurate to ±2 percent because of its higher concentration. Measurements should be made with a frequency comparable to those for ventilation air to obtain representative sampling. Measured degasification flowrates are probably known to be ±5 percent. Degasification flowrates that are estimated based on gas sales are also likely to have an uncertainty of at least ±5 percent due to the tolerances in pipeline gas quality.

For a single longwall operation, with continuous or daily emission measurements, the accuracy of monthly or annual average emissions data is probably ±5 percent. The accuracy of spot measurements performed every two weeks is ±10 percent, at 3-monthly intervals: ±30 percent. Aggregating emissions from mines based on the less frequent type of measurement procedures will reduce the uncertainty caused by fluctuations in gas production. However, as fugitive emissions are often dominated by contributions from only a small number of mines, it is difficult to estimate the extent of this improvement.

The uncertainty estimates for underground mines are shown in Table 4.1.3.

TABLE 4.1.3
ESTIMATES OF UNCERTAINTY FOR UNDERGROUND COAL MINING FOR A TIER 3 APPROACH

Source	Details	Uncertainty	Reference
Drainage gas	Spot measurements of CH_4 for drainage gas	± 2%	Expert judgment (GPG, 2000*)
	Degasification flows	± 5%	Expert judgment (GPG, 2000)
Ventilation gas	Continuous or daily measurements	± 5%	Expert judgment (GPG, 2000)
	Spot measurements every 2 weeks	± 10%	Mutmansky and Wang, 2000
	Spot measurements every 3 months	± 30%	Mutmansky and Wang, 2000
*GPG, 2000 - IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)			

ACTIVITY DATA UNCERTAINTIES

Coal production: Country-specific tonnages are likely to be known to 1-2 percent, but if raw coal data are not available, then the uncertainty will increase to about ±5 percent, when converting from saleable coal production data. The data are also influenced by moisture content, which is usually present at levels between 5-10 percent, and may not be determined with great accuracy.

Apart from measurement uncertainty, there can be further uncertainties introduced by the nature of the statistical databases that are not considered here. In countries with a mix of regulated and unregulated mines, activity data may have an uncertainty of ±10 percent

4.1.4 Surface coal mining

***ELABORATED TO ADD METHOD FOR ESTIMATING CARBON DIOXIDE EMISSIONS FROM SURFACE MINES ***

The fundamental equation to be used in estimating emissions from surface mining is as shown in Equation 4.1.6.

EQUATION 4.1.6 (ELABORATION)
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM SURFACE COAL MINING

$$CH_4\ emissions = Surface\ mining\ emissions\ of\ CH_4 + Post\text{-}mining\ emission\ of\ CH_4$$

$$CO_2\ emissions = Surface\ mining\ emissions\ of\ CO_2$$

4.1.4.1 CHOICE OF METHOD

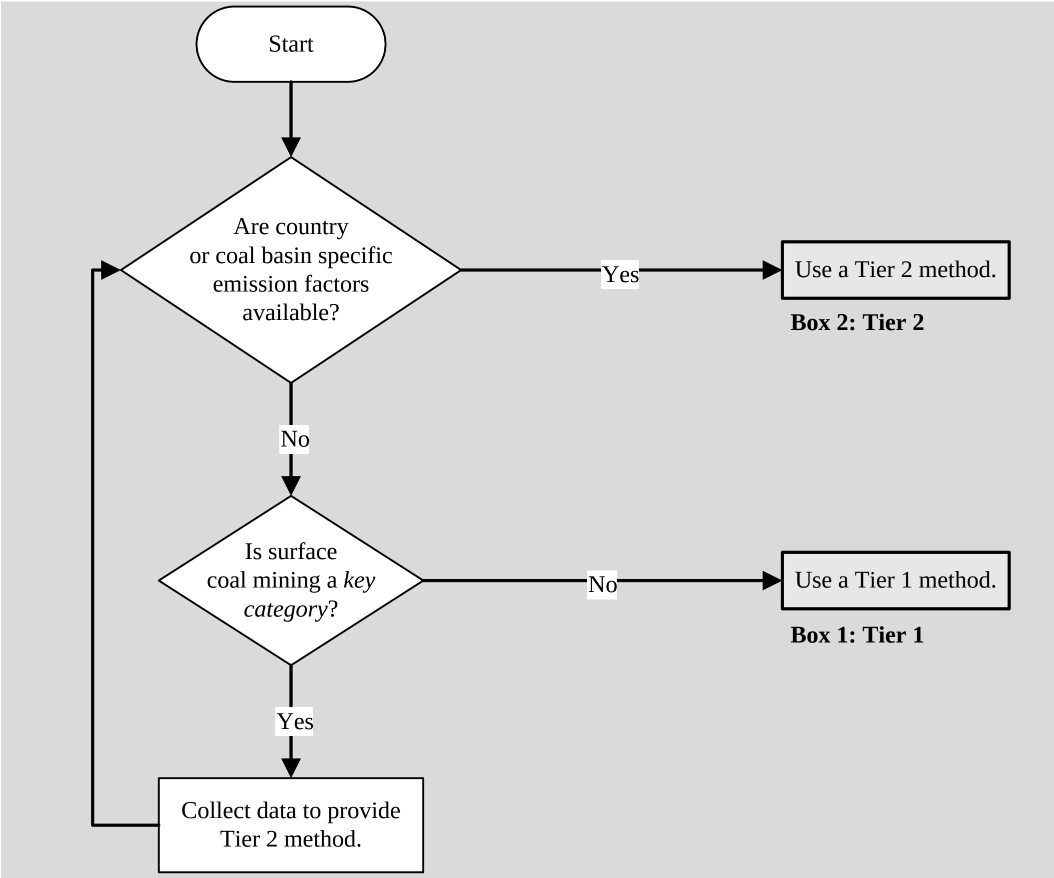
It is not yet feasible to collect mine-specific Tier 3 measurement data for surface mines. The alternative is to collect data on surface mine coal production and use emission factors. For countries with significant coal production and multiple coal basins, disaggregation of data and emission factors to the coal basin level will improve accuracy. Given the uncertainty of production-based emission factors, choosing emission factors from the range specified within these guidelines can provide reasonable estimates for a Tier 1 approach.

As with underground mining, direct measurement of post-mining emissions is infeasible so an emission factor approach is recommended. Tier 2 and Tier 1 methods should be reasonable for this source, given the difficulty of obtaining better data.

Oxidation of coal in the atmosphere to produce CO_2 is known to occur at surface mines, but emissions from this are not expected to be significant, especially taking into account the effects of rehabilitation of the waste dumps. Rehabilitation practices, which involve covering the dumps with topsoil and re-vegetation, act to reduce oxygen fluxes into the dump and hence reduce the rate of CO_2 production.

Uncontrolled combustion in waste piles is a feature for some surface mines. However, these emissions, where they occur, are extremely difficult to quantify and it is infeasible to include a methodology.

Figure 4.1.2 Decision tree for surface coal mining



Note: See Volume 1 Chapter 4, "Methodological Choice and Key Categories" (noting section 4.1.2 on limited resources) for discussion of *key categories* and use of decision trees

4.1.4.2 EMISSION FACTORS FOR SURFACE MINING

Although measurements of methane and carbon dioxide emissions from surface mining are increasingly available, they are difficult to make and at present no routine widely applicable methods exist. Data on *in situ* gas contents before overburden removal are also scarce for many surface mining operations.

The Tier 1 methane emission factors are shown together with the estimation method in Equation 4.1.7. The Tier 1 carbon dioxide emission factors are shown together with the estimation method in Equation 4.1.7.a

EQUATION 4.1.7
TIER 1: GLOBAL AVERAGE METHOD – SURFACE MINES – METHANE

$$Methane\ emissions = CH_4\ Emission\ Factor \bullet Surface\ Coal\ Production \bullet Conversion\ Factor$$

Where units are:

Methane Emissions (Gg $year^{-1}$)

CH_4 Emission Factor (m^3 $tonne^{-1}$)

Surface Coal Production (tonne $year^{-1}$)

Emissions Factor:

Low CH_4 Emission Factor = 0.3 m^3 $tonne^{-1}$

Average CH_4 Emission Factor = 1.2 m^3 $tonne^{-1}$

High CH_4 Emission Factor = 2.0 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg $m^{-3.}$

For the Tier 1 approach, it is *good practice* to use the low end of the specific emission range for those mines with average overburden depths of less than 25 meters and the high end for overburden depths over 50 meters. For intermediate depths, average values for the emission factors may be used. In the absence of data on overburden thickness, it is *good practice* to use the average emission factor, namely 1.2 m^3/tonne.

The Tier 2 method uses the same equation as for Tier 1, but with data disaggregated to country-specific, or coal basin level.

The Tier 1 carbon dioxide emission factors are shown together with the estimation method in Equation 4.1.7.a

The emission factors are based on data reported to the Australian National Greenhouse and Energy Reporting program for years 2009-17 and measurements of gas in Kazakhstan surface mines. (Commonwealth of Australia, 2017; Cook & Lloyd, 2012; Ministry of the Environment Japan, 2017; Republic of Kazakhstan, 2017; RGE "Kaz NIIEK" MOOS RK, 2010)

EQUATION 4.1.7.A
TIER 1: GLOBAL AVERAGE METHOD – SURFACE MINES– CARBON DIOXIDE

Carbon dioxide emissions = CO_2 Emission Factor ●Surface Coal Production ● Conversion Factor

Where units are:

Carbon dioxide Emissions (Gg $year^{-1}$)

CO_2 Emission Factor (m^3 $tonne^{-1}$)

Surface Coal Production (tonne $year^{-1}$)

Emissions Factor:

Low CO_2 Emission Factor = 0.37 m^3 $tonne^{-1}$

Average CO_2 Emission Factor = 0.65 m^3 $tonne^{-1}$

High CO_2 Emission Factor = 0.94 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CO_2 and converts volume of CO_2 to mass of CO_2. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $1.839 \bullet 10^{-6}$ Gg m^{-3}(GOST, 2015).

For the Tier 1 approach, it is *good practice* to use the low end of the specific emission range for those mines with average overburden depths of less than 25 meters. Otherwise countries should use the average CO_2 emission factor of 0.65 m^3/tonne unless there is country-specific evidence to support use of an alternative factor within the low/high range

The Tier 2 method uses the same equation as for Tier 1, but with data disaggregated to country-specific, or coal basin level. For countries using a Tier 2 approach, carbon dioxide emission factors may be obtained from sampling and analysis of gas content within carbonaceous strata of surface mines, prior to undertaking mining activities.

POST-MINING EMISSIONS – SURFACE MINING

For a Tier 1 approach the post-mining emissions can be estimated using the emission factors shown in Equation 4.1.8.

EQUATION 4.1.8
TIER 1: GLOBAL AVERAGE METHOD – POST-MINING EMISSIONS – SURFACE MINES

Methane emissions = CH_4 Emission Factor ● Surface Coal Production ● Conversion Factor

Where units are:

Methane Emissions (Gg $year^{-1}$)

CH_4 Emission Factor (m^3 $tonne^{-1}$)

Surface Coal Production (tonne $year^{-1}$)

Emission Factor:

Low CH_4 Emission Factor = 0 m^3 $tonne^{-1}$

Average CH_4 Emission Factor = 0.1 m^3 $tonne^{-1}$

High CH_4 Emission Factor = 0.2 m^3 $tonne^{-1}$

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}.

The average emission factor should be used unless there is country-specific evidence to support use of the low or high emission factor.

4.1.4.3 ACTIVITY DATA

As with underground coal mines, the activity data required for Tiers 1 and 2 are raw coal production. The comments relating to coal production data, made for Tier 1 and Tier 2 for underground mining in Section 4.1.3.3 also apply to surface mining.

4.1.4.4 COMPLETENESS FOR SURFACE MINING

The estimate of emissions from surface mining should include:

- Emissions during mining through the breaking of coal and from surrounding strata
- Post-mining emissions
- Waste pile/ overburden dump fires

At present only the first two sources above are taken into account. While there will be some emissions from low temperature oxidation, these are expected to be insignificant for this source.

4.1.4.5 DEVELOPING A CONSISTENT TIME SERIES

There may be missing inventory data for surface mines for certain inventory years. If there have been no major changes in the number of active surface mines, emissions can be scaled to production for the missing years. If there were changes in the number of mines, the mines involved can be removed from the scaling extrapolation and handled separately. Where new mines have started production in new coalfields, it is important that the emissions applicable to these mines be assessed as each coal basin will have different characteristic in situ gas contents and emission rates.

If coal seam degasification is practiced at surface mines, the methane should be estimated and reported in the inventory year in which the emissions and recovery operations occur.

4.1.4.6 UNCERTAINTY ASSESSMENT IN EMISSIONS

EMISSION FACTOR UNCERTAINTY

***ELABORATED TO ADD UNCERTAINTY ESTIMATES FOR SURFACE MINING CARBON DIOXIDE EMISSION FACTORS ***

Uncertainties in the emissions from surface mines are less well quantified than for underground mining. Briefly, the sources of the uncertainty are the same as described in Section 4.1.3.6 for underground coal mines. However, the variability in the emission factors for large surface mines may be expected to be greater than for underground coal mines, because surface mines can show significant variability across the extent of the mine as a result of local geological features.

Table 4.1.4 shows the Tier 1 and Tier 2 uncertainties associated with surface mining emissions.

TABLE 4.1.4 (ELABORATION)
ESTIMATES OF UNCERTAINTY FOR SURFACE MINING FOR TIER 1 AND TIER 2 APPROACHES

Likely Uncertainties of Coal Mine Methane Emission Factors for Surface Mining (Expert Judgement*)		
Method	**Surface**	**Post-Mining**
Tier 2	Factor of 2 greater or lower	± 50%
Tier 1	Factor of 3 greater or lower	Factor of 3 greater or lower
GPG, 2000 - *IPCC Good Practice Guidance* and Uncertainty Management in National Greenhouse Gas Inventories (2000)		
Likely Uncertainties of Coal Mine Carbon Dioxide Emission Factors for Surface Mining *		
Method	**Surface**	**Post-Mining**
Tier 2	Factor of 2 greater or lower	Not applicable
Tier 1	Factor of 3 greater or lower	Not applicable
* Uncertainties set to be consistent with methane emission factors		

ACTIVITY DATA UNCERTAINTY

The comments made for underground mining in Section 4.1.3.6 also apply to surface mining.

4.1.5 Abandoned underground coal mines

Closed, or abandoned, underground coal mines may continue to be a source of greenhouse gas emissions for some time after the mines have been closed or decommissioned. For the purpose of the emissions inventory, it is critical that each mine is classified in one and only one inventory database (e.g., active or abandoned).

As abandoned mines appear in these guidelines for the first time, the Tier 1 and Tier 2 approaches are described in some detail. The Tier 1 and Tier 2 approaches presented below are largely based on an approach originally developed by the USEPA (Franklin et al, 2004) and have been adapted to be more globally applicable. It is anticipated that, where country-specific data exists for abandoned mines, the country-specific data will be used.

The Tier 3 approach provides flexibility for use of mine-specific data. The Tier 3 methodology outlined below has been adapted from the USA methodology (Franklin et al 2004; US EPA 2004). Other relevant work has been sponsored by the UK (Kershaw, 2005), which provides another example of a Tier 3 approach.

4.1.5.1 CHOICE OF METHOD

The fundamental equation for estimating emissions from abandoned underground coal mines is shown in Equation 4.1.9.

EQUATION 4.1.9
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM ABANDONED UNDERGROUND COAL MINES

$$CH_4 \text{ emissions} = \text{Emissions from abandoned mines} - CH_4 \text{ emissions recovered}$$

Developing emissions estimates from abandoned underground coal mines requires historical records. Figure 4.1.3 is a decision tree that shows how to determine which Tier to use.

Tier 1 and 2

The two key parameters used to estimate abandoned mine emissions for each mine (or group of mines) are the time (in years) elapsed since the mine was abandoned, relative to the year of the emissions inventory, and emission factors that take into account the mine's gassiness. If applicable and appropriate, methane recovery at specific mines can be incorporated for specific mines in a hybrid Tier 2 – Tier 3 approach (see below).

- Tier 2 incorporates coal-type-specific information and narrower time intervals for abandonment of coal mines.
- Tier 1 includes default values and broader time intervals.

For a Tier 1 approach, the emissions for a given inventory year can be calculated from Equation 4.1.10.

EQUATION 4.1.10
TIER 1 APPROACH FOR ABANDONED UNDERGROUND MINES

$$\text{Methane Emissions} = \text{Number of Abandoned Coal Mines remaining unflooded} \bullet \text{Fraction of gassy Coal Mines} \bullet \text{Emission Factor} \bullet \text{Conversion Factor}$$

Where units are:

Methane Emissions (Gg year^{-1})

Emission Factor (m^3 year^{-1})

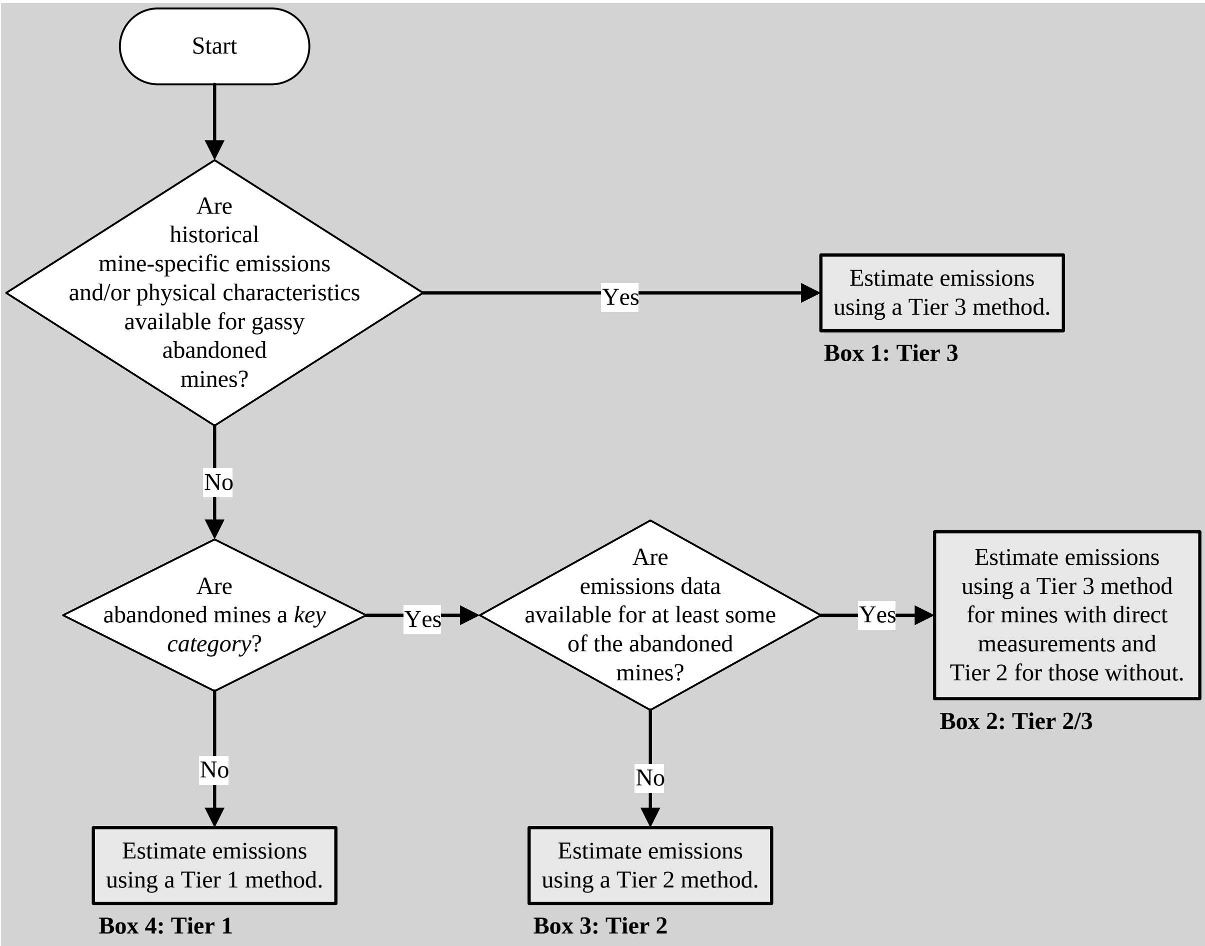
Note: the Emission Factor has different units here compared with the definitions for underground, surface and post-mining emissions. This is because of the different method for estimating emissions from abandoned mines compared with underground or surface mining.

This equation is applied for each time interval, and emissions from each time interval are added to calculate the total emissions.

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}.

Figure 4.1.3 Decision tree for abandoned underground coal mines



Note: See Volume 1 Chapter 4, "Methodological Choice and Key Categories" (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

Tier 3

The Tier 3 approaches (Franklin et al, 2004 and Kershaw, 2005) require mine-specific information such as ventilation emissions from the mine when active, characteristics of the mined coal seam, mine size and depth, and the condition of the abandoned mine (e.g., hydrologic status, flooding or flooded, and whether sealed or vented). Each country may generate its own profiles of abandoned mine emissions as a function of time (also known as emission decline curves) based on known national- or basin-specific coal properties, or it may use more generic curves based on coal rank, or measurements possibly in combination with mathematical modelling methods. If there are any methane recovery projects occurring at abandoned mines, data on these projects are expected to be available. A mine-specific Tier 3 methodology would be appropriate for calculating emissions from a mine that has associated methane recovery projects and could be incorporated as part of a hybrid approach with a national level Tier 2 emissions inventory.

In general, the Tier 3 process for developing a national inventory of abandoned mine methane (AMM) emissions consists of the following steps:

1. Creating a database of gassy abandoned coal mines.
2. Identifying key factors affecting methane emissions: hydrologic (flooding) status, permeability mine condition (whether sealed or vented) and time elapsed since abandonment.
3. Developing mine- or coal basin-specific emission rate decline curves, or equivalent models.
4. Validating mathematical models through a field measurement programme.
5. Calculating a national emissions inventory for each year.
6. Adjusting for emissions reductions due to methane recovery and utilization.
7. Determining the net total emissions.

Hybrid Approaches

A combination of different Tier methodologies may be used to reflect the best data availability for different historical periods. For example, for a given country, emissions from mines abandoned in the distant past may need to be determined using a Tier 1 method. For that same country, it may be possible to determine emissions from mines abandoned more recently using a Tier 2 or 3 method if more accurate data are available.

Fully Flooded Mines

It is *good practice* to include mines that are known to be fully flooded in databases and other records used for inventory development, but they should be assigned an emission of zero as the emissions from such mines are negligible.

Emissions Reductions through Recovery and Utilization

In some cases, methane from closed or abandoned mines may be recovered and utilised or flared. Methane recovery from abandoned mines generally entails pumping which increases, or “accelerates”, the amount of methane recovered above the amount that would have been emitted had pumping not taken place.

Under a mine-specific (Tier 3) approach in which emissions decline curves or models are used to estimate emissions, if emissions reductions are less than the projected emissions that would have occurred at the mine had recovery not taken place for a given year, then the emissions reductions from the recovery and utilization should be subtracted from the projected emissions to provide the net emissions. If the methane recovered and utilized in a given year exceeds the emission that would have occurred had recovery not taken place, then the net emissions from that mine for that year are considered to be zero.

If a Tier 3 method is not used (singly or in combination with Tier 2), the total amount of methane recovered and utilized from abandoned mines should be subtracted from the total emissions inventory for abandoned mines, per Equation 4.1.9, subject to the reported emissions being no less than zero. The Tier 3 method should be used where suitable data are available.

4.1.5.2 CHOICE OF EMISSION FACTORS

Tier 1: Global Average Approach – Abandoned Underground Mines

A Tier 1 approach for determining emissions from abandoned underground mines is described below and is largely based on methods developed by the USEPA (Franklin et al , 2004). It incorporates a factor to account for the fraction of those mines that, when they were actively producing coal, were considered gassy. Thus, this methodology is based on the total number of coal mines abandoned, adjusted for the fraction considered gassy, as described below. Abandoned mines that were considered non-gassy when they were actively mined are presumed to have negligible emissions. In the US methodology, the term gassy mines refers to coal mines that, when they were active, had average annual ventilation emissions that exceeded the range of 2 800 to 14 000 cubic meters per day (m^3/d), or 0.7 to 3.4 Gg per year.

The Tier 1 – approach for abandoned underground coal mines is as follows:

1. Determine the approximate time (year interval) from the following time intervals when gassy coal mines were abandoned:

   a. 1901 – 1925
   b. 1926 – 1950
   c. 1951 – 1975
   d. 1976 – 2000
   e. 2001 – present

2. Multiple intervals may be used where appropriate. It is recommended that the number of gassy coal mines abandoned during each time interval be estimated using the smallest time intervals possible based on available data. Ideally, for more recent periods, time intervals will decrease (e.g., intervals of ten years prior to 1990; annual intervals since 1990). Information for different coal mine-clusters abandoned during different time periods should be considered, since multiple time periods may be combined in the Tier 1 approach

3. Estimate the total number of abandoned mines in each time band since 1901 remaining unflooded. If there is no knowledge on the extent of flooding it is *good practice* to assume that 100 percent of mines remain unflooded. For the purposes of estimating the number of abandoned mines, prospect excavations and hand cart mines of only a few acres in size should be disregarded.

4. Determine the percentage of coal mines that would be considered gassy at the time of mine closure. Based on the time intervals selected above, choose an estimated percentage of gassy coal mines from the high and low default values listed in Table 4.1.5. Actual estimates can range anywhere from 0 to 100 percent. When choosing within the high and low default values listed in Table 4.1.5, a country should consider all available historical information that may contribute to the percentage of gassy mines, such as coal rank, gas content, and depth of mining. Countries with recorded instances of gassy mines (e.g., methane explosions or outbursts) should choose the high default values in the early part of the century. From 1926 to 1975, countries where mines were relatively deep and hydraulic equipment was used should choose the high default value. Countries with deep longwall mines or with evidence of gassiness should choose the high values for the time periods after 1975. The low range of the default values may be appropriate for a given time interval for specific regions, coal basins, or nations, based on geologic conditions or known mining practices.

5. For the inventory year of interest (between 1990 and the present), select the appropriate emissions factor from Table 4.1.6. For example, for mines abandoned in the interval 1901 to 1925 and for the inventory reporting year 2005, the Emission Factor for these mines would have a value of 0.256 million m^3 of methane per mine.

6. Calculate for each time band the total methane emissions from Equation 4.1.10 to the inventory year of interest.

7. Sum the emissions for each time interval to derive the total abandoned mine emissions for each inventory year.

TABLE 4.1.5
TIER 1 – ABANDONED UNDERGROUND MINES
DEFAULT VALUES - PERCENTAGE OF COAL MINES THAT ARE GASSY

Time Interval	**Low**	**High**
1900-1925	0%	10%
1926-1950	3%	50%
1950-1976	5%	75%
1976-2000	8%	100%
2001-Present	9%	100%

TABLE 4.1.6
TIER 1 – ABANDONED UNDERGROUND MINES
EMISSION FACTOR, MILLION M^3 METHANE / MINE

	Interval of mine closure				
Inventory Year	**1901 – 1925**	**1926 – 1950**	**1951 - 1975**	**1976 – 2000**	**2001 – Present**
1990	0.281	0.343	0.478	1.561	NA
1991	0.279	0.340	0.469	1.334	NA
1992	0.277	0.336	0.461	1.183	NA
1993	0.275	0.333	0.453	1.072	NA
1994	0.273	0.330	0.446	0.988	NA
1995	0.272	0.327	0.439	0.921	NA
1996	0.270	0.324	0.432	0.865	NA
1997	0.268	0.322	0.425	0.818	NA
1998	0.267	0.319	0.419	0.778	NA
1999	0.265	0.316	0.413	0.743	NA
2000	0.264	0.314	0.408	0.713	NA
2001	0.262	0.311	0.402	0.686	5.735
2002	0.261	0.308	0.397	0.661	2.397
2003	0.259	0.306	0.392	0.639	1.762
2004	0.258	0.304	0.387	0.620	1.454
2005	0.256	0.301	0.382	0.601	1.265
2006	0.255	0.299	0.378	0.585	1.133
2007	0.253	0.297	0.373	0.569	1.035
2008	0.252	0.295	0.369	0.555	0.959
2009	0.251	0.293	0.365	0.542	0.896
2010	0.249	0.290	0.361	0.529	0.845
2011	0.248	0.288	0.357	0.518	0.801
2012	0.247	0.286	0.353	0.507	0.763
2013	0.246	0.284	0.350	0.496	0.730
2014	0.244	0.283	0.346	0.487	0.701
2015	0.243	0.281	0.343	0.478	0.675
2016	0.242	0.279	0.340	0.469	0.652

As abandoned underground mines are included for the first time an example calculation has been included in Table 4.1.7.

TABLE 4.1.7
TIER 1 – ABANDONED UNDERGROUND MINES
EXAMPLE CALCULATION

	Interval of mine closure					
	1901 – 1925	**1926 – 1950**	**1951 - 1975**	**1976 – 2000**	**2001 – Present**	**Total for inventory year 2005**
Number of mines closed per time band	20	15	10	5	1	
Fraction of gassy mines	0.1	0.5	0.75	1.0	1.0	
Emission factor for Inventory year, 2005 (from Table 4.1.6)	0.256	0.301	0.382	0.601	1.265	
Total emissions (Gg CH_4 per year from Eqn 4.1.10)	0.34	1.51	1.92	2.07	0.85	6.64

Tier 2 – Country- or Basin-Specific Approach

The Tier 2 approach for developing an abandoned mine methane emission inventory follows a similar approach to Tier 1, but it incorporates country- or basin-specific data. The methodology presented below is intended to utilize coal basin-specific or country-specific data wherever possible (for example, for active mine emissions prior to abandonment, for basin-specific parameters for emissions factors, etc.).

In some cases, default parameters have been provided for these values but these should be used only if country-specific or basin-specific data are not available.

Calculate emissions for a given inventory year using Equation 4.1.11:

EQUATION 4.1.11
TIER 2 APPROACH FOR ABANDONED UNDERGROUND MINES WITHOUT METHANE RECOVERY AND UTILIZATION

Methane Emissions = Number of Coal Mines Abandoned Remaining Unflooded ● Fraction of Gassy Mines ● Average Emissions Rate ● Emission Factor ● Conversion Factor

Where units are:

Emissions of methane (Gg year^{-1})

Emission Rate (m^3 year^{-1})

Emission Factor (dimensionless, see Equation 4.1.11)

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67●10^{-6} Gg m^{-3}

If individual mines are known to be completely flooded, they may be assigned an emissions value of zero. Methane emissions reductions due to recovery projects that utilize or flare methane at abandoned mines should be subtracted from the emissions estimate. For either of these cases, it is recommended that a hybrid Tier 2 – Tier 3 approach be used to incorporate such mine-specific information (see the discussion of methane recovery and utilization projects from abandoned mines, Sections 4.1.5.1 and 4.1.5.3).

The basic steps in the Tier 2 approach for abandoned underground coal mines are as follows:

- Determine the approximate time interval(s) when significant numbers of gassy coal mines were closed. Multiple intervals may be used where appropriate. It is recommended that the number of gassy coal mines abandoned during each time interval be estimated using the smallest time intervals possible based on available data. Ideally, for more recent periods, time intervals will decrease (e.g., intervals of ten years prior to 1990; annual intervals since 1990).
- Estimate the total number of abandoned mines in each time interval selected remaining unflooded. If there is no available information on the flooded status of the abandoned mines, assume 100 percent remain unflooded.
- Determine the number (or percentage) of coal mines that would be considered gassy at the time of mine closure.
- For each time interval, determine the average emissions rate. If country or basin-specific data do not exist, low and high estimates for active mine emissions prior to abandonment can be selected from Table 4.1.8.
- For each time interval, calculate an appropriate emissions factor using Equation 4.1.12, based on the difference in years between the estimated data of abandonment and the year of the emissions inventory. Note that default values for this emissions factor equation are provided in Table 4.1.9, but these default values should be used only where country- or basin-specific information are not available.
- Calculate the emissions for each time interval using Equation 4.1.11.
- Sum the emissions for each time interval to derive the total abandoned mine emissions for each inventory year.

TABLE 4.1.8
TIER 2 – ABANDONED UNDERGROUND COAL MINES
DEFAULT VALUES FOR ACTIVE MINE EMISSIONS PRIOR TO ABANDONMENT

Parameter	Emissions, million m^3/yr
Low	1.3
High	38.8

EQUATION 4.1.12
TIER 2 – ABANDONED UNDERGROUND COAL MINES EMISSION FACTOR

$$Emission\ Factor = (1 + aT)^{b}$$

Where:

a and *b* are constants determining the decline curve. Country or basin-specific values should be used wherever possible. Default values are provided in Table 4.1.9, below.

T = years elapsed since abandonment (difference of the mid point of the time interval selected and the inventory year) and inventory year.

A separate emission factor must be calculated for each time interval selected. This emission factor is dimensionless.

TABLE 4.1.9
COEFFICIENTS FOR TIER 2 – ABANDONED UNDERGROUND COAL MINES

Coal Rank	A	b
Anthracite	1.72	-0.58
Bituminous	3.72	-0.42
Sub-bituminous	0.27	-1.00

Tier 3-Mine-Specific Approach

Tier 3 provides a great deal of flexibility. Directly measured emissions, where available, can be used in place of estimates and calculations. Models may be used in conjunction with measured data to estimate time series emissions. Each country may generate their own decline curves or other characterizations based on measurements, known basin-specific coal properties, and/or hydrological models. Equation 4.1.13 describes one possible, approach.

EQUATION 4.1.13
EXAMPLE OF TIER 3 EMISSIONS CALCULATION – ABANDONED UNDERGROUND MINES

$$Methane\ Emissions = (Emission\ rate\ at\ closure \bullet Emission\ Factor \bullet Conversion\ Factor) - Methane\ Emissions\ Reductions\ from\ Recovery\ and\ Utilisation$$

Where units are:

Methane Emissions (Gg $year^{-1}$)

Emission rate at Closure (m^3 $year^{-1}$)

Emission Factor (dimensionless, see Franklin *et al.*, 2004)

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of $0.67 \bullet 10^{-6}$ Gg m^{-3}.

The basic steps in the Tier 3 methodology involve the following:

- Determine a database of mine closures with relevant geological and hydrological information and the approximate abandonment dates (when all active mine ventilation ceased) consistently for all mines in the country's inventory.
- Estimate emissions based on measured emissions and/or an emissions model. This may be based on the average emission rate at time of mine closure, determined by the last measured emission rate (or preferably, an average of several measurements taken the year prior to abandonment), or estimated methane reserves susceptible to release.
- If actual measurements have not been taken at a given mine, emissions may be calculated using an appropriate decline curve or modelling approach for openly vented mines, sealed mines, or flooded mines. Use the selected decline equation or modelling approach for the mine and the number of years between abandonment and the inventory year to calculate emissions or an appropriate emission factor for each mine.
- Sum abandoned mine emissions to develop an annual inventory.

4.1.5.3 CHOICE OF ACTIVITY DATA

Estimating emissions from abandoned mines requires historical data, rather than current activity data. For Tier 1, country experts should estimate the number of mines abandoned by time interval in Table 4.1.5, on the basis of historical data available from appropriate national international agencies or regional experts.

For Tier 2, the total number of abandoned mines and the time period of their abandonment are required. These data may be obtained from appropriate national, state, or provincial agencies, or companies active in the coal industry. If a country consists of more than one coal region or basin, production and emissions data may be disaggregated by region. Expert judgment and statistical analysis may be used to estimate ventilation emissions or specific emissions based on measurements from a limited number of mines (see Franklin et al (2004)).

For Tier 3, abandoned coal mine emissions estimates should be based on detailed data about the characteristics, data of abandonment and geographical location of individual mines. In the absence of direct measurements of the abandoned mine, Tier 3 emissions factors may be based on mine-specific emissions data, including historical emissions data from degasification and ventilation systems when the mine(s) were active (see Franklin et al, 2004).

EMISSIONS REDUCTIONS FROM METHANE RECOVERY AT ABANDONED MINES

Abandoned mines where recovery and utilisation or flaring of abandoned mine methane is taking place should be accounted for by comparing the amount of methane recovered and utilized with the amount expected to have been emitted naturally. The method for accounting for methane recovered from abandoned coal mines is described in Section 4.1.5.1.

The CO_2 emissions produced from combustion of methane from abandoned mine recovery and utilization projects should be included in the energy sector estimates where there is utilisation, or under fugitive abandoned mine emissions where there is flaring. To make this estimate, abandoned mine methane project recovery or production data may be publicly available through appropriate government agencies depending on the end use. This information may be in the form of metered gas sales and is often publicly available in oil and gas industry or governmental databases. An additional 3 to 8 percent of undocumented abandoned mine methane is typically recovered and used as fuel for compression of the gas. The actual percentage of methane used will depend on the efficiency of the compression equipment. The emissions from this energy use should be reported under Volume 2, Chapter 2 ‘Stationary Combustion’. For projects that use recovered methane from abandoned mines for electricity generation, metered flow rates and compression factors, if available, can be used. If public data accurately reflect electricity produced, then the heat rate or efficiency of the electricity generator can be used to determine its fuel consumption rate.

4.1.5.4 COMPLETENESS

The emissions estimates from abandoned underground mines should include all emissions leaking from the abandoned mines. Until recently, there were no methods by which these emissions could be estimated. *Good practice* is to record the date of mine closure and the method of sealing. Data on the size and depth of such mines would be useful for any subsequent estimation.

4.1.5.5 DEVELOPING A CONSISTENT TIME SERIES

It is unlikely that comprehensive mine-by-mine (Tier 3) data will be available for all years. Therefore, in order to prepare hybrid Tier 2 – Tier 3 inventories, as well as Tier 1 or Tier 2 inventories, the number of abandoned mines may need to be estimated for years for which there are sparse data.

These inventory guidelines recommend that methane emissions associated with abandoned mines should be accounted for in the inventory year in which the emissions and recovery operations occur.

For situations where the emissions of greenhouse gases from active underground mines have been well characterized and the mines have passed from being considered ‘active’ to ‘abandoned’, data from the active mine emissions (during the year in which the mine was closed) should be collected. Great care should be taken in transferring mines from the active to the abandoned inventory so that no double-counting or omissions occur.

4.1.5.6 UNCERTAINTY ASSESSMENT

TIER 1

The primary causes of the uncertainty related to the Tier 1 methodology include the following:

- *The global nature of the emission factors.* The range of uncertainty of these emission factors is intentionally large to account for the uncertainty in the determining parameters such as mine size, mine depth, and coal rank.
- *Time of abandonment.* Because emissions from abandoned mines are strongly time dependent, selecting a single interval that best represents the dates of closure for all mines is critical in establishing an emissions rate.
- *The activity data.* Both the number of gassy abandoned mines and the amount of coal that has been produced from gassy mines are strongly country-dependent. The uncertainty will be defined by the availability of historic mining and production records.

The total estimated range of uncertainty associated with Tier 1 estimations will depend on each of the factors discussed above. Actual emissions are likely to be in the range of one-third to three times the estimated emissions value.

TIER 2

The primary causes of uncertainty related to the Tier 2 approaches include the following:

- *The country- or basin-specific emission factors.* Uncertainty is associated with the emission factor decline equations for each coal rank. This uncertainty is a function of the inherent variability of gas content, adsorption characteristics, and permeability within a given coal rank.
- The number of mines producing a given coal rank.
- The number of mines abandoned through time.
- The percentage of gassy mines as a function of time.

The total estimated uncertainty associated with Tier 2 estimations depends on the range of uncertainty associated with each of these factors. These parameters should be more narrowly defined than for Tier 1. Thus, total actual emissions are likely to be in the range of one-half to twice the estimated value.

TIER 3

The primary uncertainties associated with emissions inventories generated using the Tier 3 methodology include the following:

- Active mine emission rate
- Decline curve equation or modelling approach that describes the function relating adsorption characteristics and gas content of the coal, mine size, and coal permeability
- Hydrological status of the abandoned mine (flooded or flooding) and condition (sealed or vented).

The Tier 3 methodology has lower associated uncertainty than Tiers 1 and 2 because the emissions inventory is based either on direct measurements or on mine-specific information including active emission rates and mine closure dates. Although the range of uncertainty associated with estimated emissions from an individual mine may be large (in the ±50 percent range), summing the uncertainty range of a sufficient number of individual mine emissions actually reduces the range of uncertainty of the final inventory, per the central limits theorem (Murtha, 2002), provided the uncertainties are independent. Given the expected range of the number of abandoned coal mines across different countries, the overall uncertainty associated with Tier 3 methodology for abandoned mines may vary from ±20 percent for countries with a large number of abandoned mines to ±30 percent for a country with a fewer number of abandoned mines whose emissions are included in the inventory.

A combination of different Tiers may be used. For example, the emissions from mines abandoned during the first half of the twentieth century may be determined using a Tier 1 method, while emissions from mines abandoned after 1950 may be determined using a Tier 2 method. The Tier 1 and Tier 2 methods will each have their own uncertainty distribution. It is important to properly sum these distributions in order to arrive at the appropriate range of uncertainty for the final emissions inventory.

4.1.6 Coal Exploration

4.1.6.1 CHOICE OF METHOD

Assessment of emission of methane from exploration boreholes in a coalfield will be a function of the gas content, cumulative thickness of the coal seams encountered during exploratory drilling and geological discontinuity, if any, near the borehole. Since this information is not readily available in the exploration or any other report.

However, annual updating of National Inventory is an integral part of coal exploration. Therefore, augmentation of coal resources in a year over that of the preceding year can be easily ascertained and may be used as activity data for exploration boreholes.

4.1.6.2 CHOICE OF EMISSION FACTORS

No results are available in the literature on measurement of fugitive emission specifically from coal exploration boreholes.

For a Tier 1 approach the exploratory borehole emissions factors are shown below together with the estimation method:

EQUATION 4.1.14
TIER 1: GLOBAL AVERAGE METHOD
Methane emissions = CH_4 Emission Factor ● Augmentation of Resource ● Conversion Factor

Where units are:

Methane Emissions (Gg year^{-1})

CH_4 Emission Factor (m^3 tonne^{-1})

Augmentation of Resource (tonne year^{-1})

Emission Factor:

Low CH_4 Emission Factor = 0.001 m^3 tonne^{-1}

Average CH_4 Emission Factor =0.005 m^3 tonne^{-1}

High CH_4 Emission Factor = 0.01 m^3 tonne^{-1}

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67●10^{-6} Gg m^{-3}.

For a Tier 2 approach the exploratory borehole emissions factors are shown below together with the estimation method:

EQUATION 4.1.15
TIER 2: DEPTHWISE METHOD
Methane emissions = CH_4 Emission Factor ● Augmentation of Resource ● Conversion Factor

Where units are:

Methane Emissions (Gg year^{-1})

CH_4 Emission Factor (m^3 tonne^{-1})

Augmentation of Resource (tonne year^{-1})

Emission Factor:

CH_4 Emission Factor = 0.001 m^3 tonne^{-1} for depth range 0 – 300m

CH_4 Emission Factor =0.002 m^3 tonne^{-1} for depth range 300 – 600m

CH_4 Emission Factor = 0.02 m^3 tonne^{-1} for depth range 600 – 1200m

Conversion Factor:

This is the density of CH_4 and converts volume of CH_4 to mass of CH_4. The density is taken at 20˚C and 1 atmosphere pressure and has a value of 0.67●10^{-6} Gg m^{-3}.

4.1.6.3 CHOICE OF ACTIVITY DATA

Augmentation of resources or new addition of resources in the year may be used as Activity data, which may be available in the inventory of coal or lignite resources or can be easily obtained by subtracting the resources for a year and the resources for the previous year as follows:

Augmentation or New Addition = Resource for a year – Resource for the previous year

The above activity data may be used for Tier 1 estimates. A precise value for activity data may be category-wise net augmentation of quality-wise resource or a more accurate value for net increase of depth-wise resource. These values of activity data may correspond to higher Tier estimates.

4.1.6.4 COMPLETENESS

[Will be provided in the second order draft.]

4.1.6.5 DEVELOPING A CONSISTENT TIME SERIES

[Will be provided in the second order draft.]

4.1.6.6 UNCERTAINTY ASSESSMENT

[Will be provided in the second order draft.]

4.1.7 Completeness for coal mining

These are abandoned surface mines and uncontrolled combustion..

ABANDONED SURFACE MINES

After closure, emissions from abandoned surface mines may include the following:

- The standing highwall
- Leakage from the pit floor
- Low temperature oxidation
- Uncontrolled combustion

At present, no comprehensive methods to quantify these emissions have been developed and therefore they have not been included in these guidelines. They remain subjects for further research.

EMISSIONS FROM UNCONTROLLED COMBUSTION AND BURNING COAL DEPOSITS

While emissions from this source may be significant for an individual coal mine, it is unclear as to how significant these emissions may be for an individual country. In some countries where such fires are widespread, the emissions may be very significant. There are no clear methods available at present to systematically measure or precisely estimate the activity data, though where countries have data on amounts of coal burned, the CO_2 should be estimated on the basis of the carbon content of the coal and reported in the relevant subcategory of 1.B.1.b. It is noted that uncontrolled combustion only due to coal exploration activities is considered here. Care should be taken to avoid double counting with fugitive CH_4 and low oxidation CO_2 emissions.

4.1.8 Inventory Quality Assurance/Quality Control (QA/QC)

4.1.8.1 QUALITY CONTROL AND DOCUMENTATION

EMISSION FACTORS

- **Quality control**
  - a) Tier 1: reviewing the national circumstances and documenting the rationale for selecting specific values.
  - b) Tier 2: checking the equations and calculations used to determine the emissions factor, and ensuring that sampling follows consistent protocols so that conditions are representative and uniform
  - c) Tier 3: working with mine operators to ensure the quality of data from degasification systems. Individual operating mines should already have in place QA/QC procedures for monitoring ventilation emissions.

- **Documentation**

  Provide transparent information on the steps to calculate emissions factors or measure emissions, including the numbers and the sources of any data collected.

ACTIVITY DATA

- **Quality control**

  Describe activity data collection methods, including an assessment of areas requiring improvement.

- **Documentation**

  a) Comprehensive description of the methods used to collect the activity data

  b) Discussion of potential areas of bias in the data, including a discussion of whether the characteristics are representative of the country

INVENTORY COMPILER REVIEW (QA)

The inventory compiler should ensure that suitable methodologies are used to calculate emissions from coal mining, including use of the highest applicable Tier for a given country, taking into account what are considered *key category* for that country as well as the availability of data. The inventory compiler should ensure that appropriate emission factors are used. For active underground and surface mines, the best available activity data should be used in accordance with the appropriate Tiers, especially the amount of methane recovered and utilized wherever possible. For abandoned mines, the compiler should ensure the most accurate available historical information is used.

INVENTORY COMPILER QC ON COMPILING NATIONAL EMISSIONS

Methods the inventory compiler can employ to provide quality control for the national inventory may include, for example:

- Back-calculating national and regional emission factors from Tier 3 measurement data, where applicable
- Ensuring that emission factors are representative of the country (for Tier 1 and Tier 2)
- Ensuring that all mines are included
- Comparing with national trends to look for anomalies

EXTERNAL INVENTORY QUALITY ASSURANCE (QA/QC) SYSTEMS

The inventory compiler should arrange for an independent, objective review of calculations, assumptions, and/or documentation of the emissions inventory to be performed to assess the effectiveness of the QC programme. The peer review should be performed by expert(s) who are familiar with the source category and who understand inventory requirements.

4.1.8.2 REPORTING AND DOCUMENTATION

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates as outlined in Volume 1, chapter 8 of the *2006 IPCC Guidelines.*

The national inventory report should include summaries of methods used and references to source data such that the reported emissions estimates are transparent and steps in their calculation may be retraced. However, to ensure transparency, the following information should be supplied:

- Emissions by underground, surface, and post-mining components of CH_4 and CO_2 (where appropriate), the method used for each of the sub-source categories, the number of active mines in each sub-source category and the reasons for the chosen emission factors (e.g. depth of mining, data on *in situ* gas contents etc.). The amount of drained gas and the degree of any mitigation or utilisation should be presented with a description of the technology used, where appropriate.
- Activity data: Specify the amount and type of production, underground and surface coal, listing raw and saleable amounts where available.
- Where issues of confidentiality arise, the name of the mine need not be disclosed. Most countries will have more than three mines, so mine-specific production cannot be back calculated from the emission estimates.

It is important to ensure that in the transition of mines from ‘active’ to ‘abandoned’ each mine is included once and only once in the national inventory.

4.2 FUGITIVE EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS

UPDATED TO REFLECT INCLUSION OF TOWN GAS AND BIOGAS, PROVIDE CLARIFICATION ON COALBED METHANE AND ON SYSTEM BOUNDARY (I.E. INCLUDES LEAKS FROM APPLIANCES)

This section is an update of Section 4.2 in Vol.2 of the *2006 IPCC Guidelines*. Fugitive emissions from oil and natural gas systems are accounted for in IPCC subcategory 1.B.2 of the energy sector. For reporting purposes, this subcategory is subdivided as shown in Figure 4.2.1. The main distinction is made between oil and natural gas systems, with each being subdivided into the different parts (or segments) of the oil or gas system according to the type of activity. Fuel gases other than natural gas, such as town gas[2] and biogas, are often handled in natural gas systems (such as transmission and distribution systems), and are discussed here as well. Where coalbed methane is produced into a natural gas gathering system, any associated fugitive emissions should be reported under the appropriate natural gas exploration and production categories.

The term fugitive emissions is broadly applied here to mean all greenhouse gas emissions from oil and gas systems except contributions from fuel combustion. Fugitive emissions include vented emissions, leak emissions, and flaring emissions. Oil and natural gas systems comprise all infrastructure required to produce, collect, process or refine and deliver natural gas and petroleum products to market. The system begins at the wellhead, or oil and gas source, and ends at the consumer (including fugitive emissions from appliances). Emissions excluded from this category are as follows:

- Fuel combustion for the production of useful heat or energy by stationary or mobile sources (see Chapters 2 and 3 of the Energy Volume).
- Fugitive emissions from carbon capture and storage projects, the transport and disposal of acid gas from oil and gas facilities by injection into secure underground formations, or the transport, injection and sequestering of CO_2 as part of enhanced oil recovery (EOR), enhanced gas recovery (EGR) or enhanced coal bed methane (ECBM) projects (see Chapter 5 of the Energy Volume on carbon dioxide capture and storage systems). Note that fugitive emissions from the oil and gas production portions of EOR, EGR and ECBM projects <u>are</u> part of Category 1.B.2.
- Fugitive emissions that occur at industrial facilities other than oil and gas facilities (see the Industrial Processes and Product Use Volume).
- Fugitive emissions from waste disposal activities that occur outside the oil and gas industry (see the Waste Volume).
- Where a coal formation is degassed for the purposes of coal exploration or coal mining and handling, the associated emissions should be allocated to the coal sector under the appropriate section of IPCC category 1.B.1.

When determining fugitive emissions from oil and natural gas systems it may be necessary to apply greater disaggregation than is shown in Figure 4.2.1 to better account for local factors affecting the amount of emissions (i.e., reservoir conditions, processing/treatment requirements, design and operating practices, age of the industry, market access, regulatory requirements and the level of regulatory enforcement), and to account for changes in activity levels in progressing through the different parts of the system. The percentage contribution by each category in Figure 4.2.1 to total fugitive emissions by the oil and gas sector will vary according to a country's circumstances and the amount of oil and gas imported and exported. Some examples of the potential distribution of fugitive emissions by subcategory are provided in the API (2009) Compendium.

[2] Town gas (also called coal gas) is a manufactured gaseous fuels produced for sale to commercial and residential consumers. Coal gas contains hydrogen (around 50%), carbon monoxide (around 10%), methane (around 35%) and volatile hydrocarbons (around 5%) together with carbon dioxide and nitrogen (each less than 1%). It was used in Europa until the end of the last millennium and is still used in China (http://www.hks.harvard.edu/m-rcbg/heep/papers/HEEP%20Discussion%2012.pdf).

4.2.1 Overview, description of sources

UPDATED TO REFLECT UPDATED PRACTICES, INCLUDING TWO UPDATED FIGURES

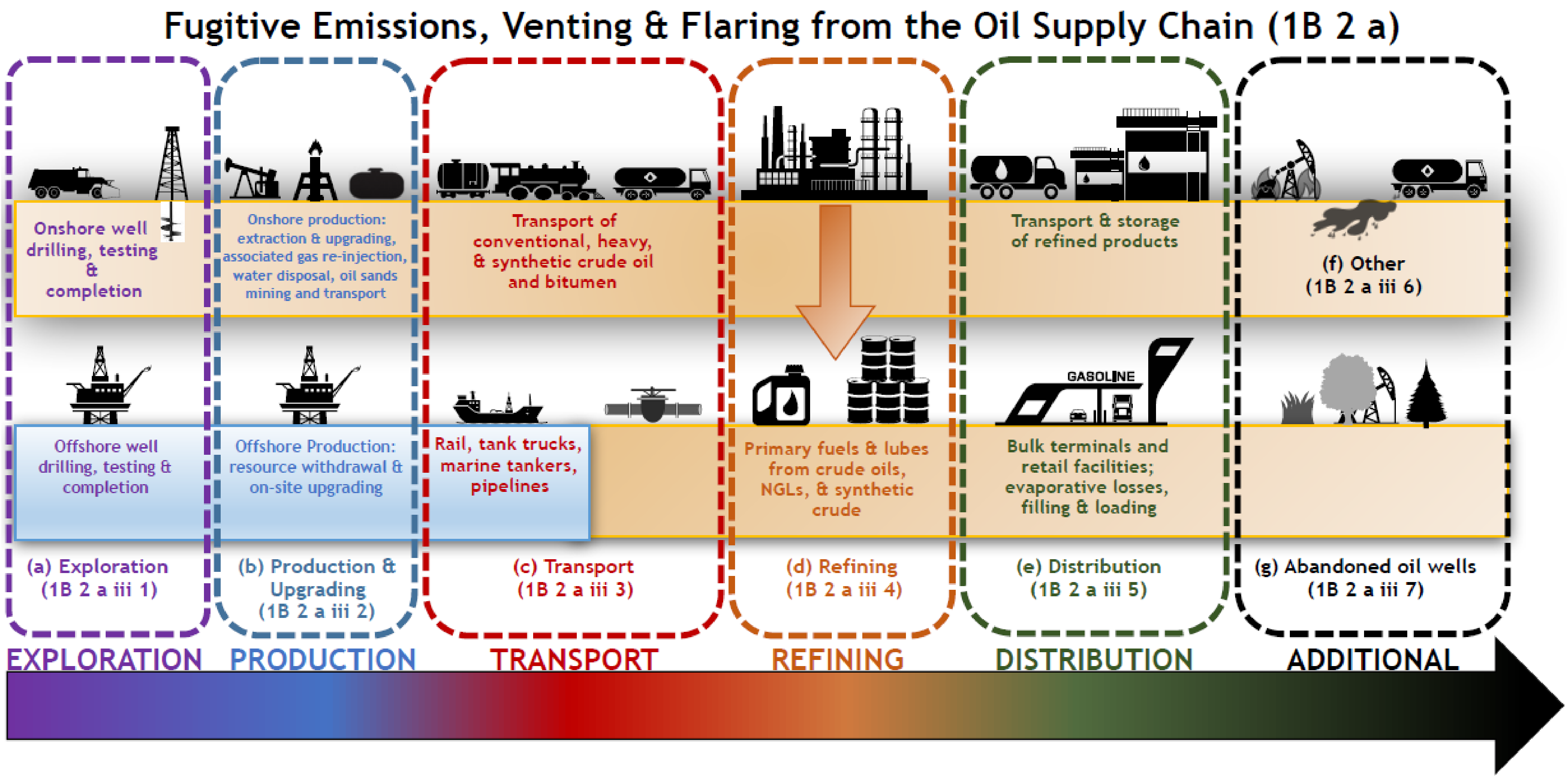
The sources of fugitive emissions on oil and gas systems include, but are not limited to, equipment leaks, evaporation and flashing losses, venting, flaring, incineration and accidental releases (e.g., pipeline dig-ins, well blow-outs and spills). Venting and flaring emission sources are engineered or intentional (e.g., tank, seal and process vents and flare systems), while leak emissions are not. Some emissions are relatively well-characterised, with use of measurement systems in certain cases, where losses or flows are tracked as part of routine production accounting procedures, or where engineering estimates are made. Uncertainties associated with such estimates include those due to an inability to cover the wide range of flows and variations in composition that may occur, and inconsistencies in the activities that are accounted for. A lack of data on activities and practices in place in a country can also contribute to uncertainty. Throughout this chapter, an effort is made to state the precise type of fugitive emission source being discussed, and to only use the term fugitive emissions or fugitive emission sources when discussing these emissions or sources at a higher, more aggregated, level.

Streams containing pure or high concentrations of CO_2 may occur at oil production facilities where CO_2 is being injected into an oil reservoir for EOR, ECBM or EGR. They may also occur at gas processing, oil refining and heavy oil upgrading facilities as a by-product of gas treating to meet sales or fuel gas specifications, and at refineries and heavy oil upgraders as a by-product of hydrogen production. Where CO_2 occurs as a process by-product it is usually vented to the atmosphere, injected into a suitable underground formation for disposal or supplied for use in EOR projects. Fugitive CO_2 emissions from these streams should be accounted for under the appropriate subcategories of 1.B.2. Fugitive CO_2 emissions from CO_2 capture should be accounted for in the industry where capture occurs, while the fugitive CO_2 emissions from transport, injection and storage activities shall be accounted for separately in category 1.C (refer to Chapter 5).

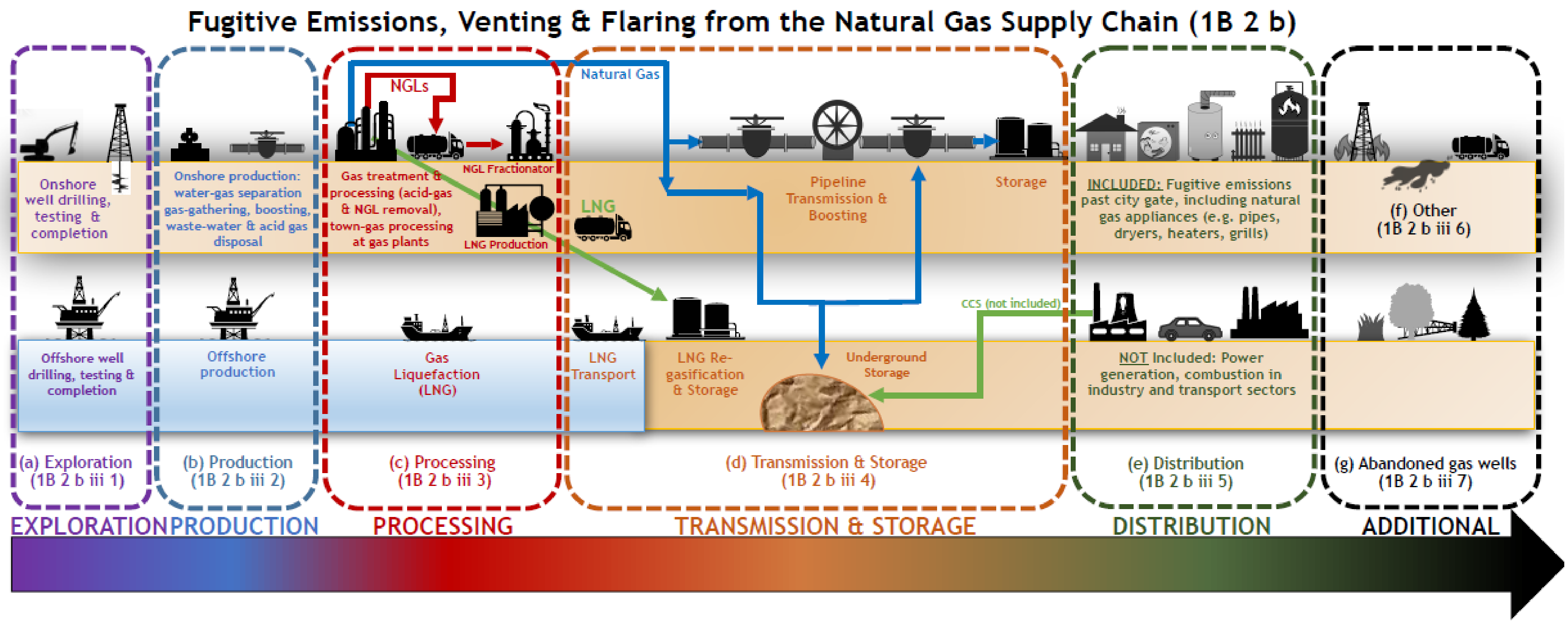
EOR is the recovery of oil from a reservoir by means other than using the natural reservoir pressure. It can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. EOR generally results in increased amounts of oil being removed from a reservoir in comparison to methods using natural pressure or pumping alone. The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (CO_2 injection or hydrocarbon injection), and thermal recovery (steamflood or *in-situ* combustion).

Emissions from oil and gas exploration are disaggregated to reflect that unconventional completions (i.e., conducted with hydraulic fracturing) have a different emissions profile than conventional completions (e.g. conducted without hydraulic fracturing). Conventional reservoirs are those in which hydrocarbons are sealed below a capstone and from which hydrocarbons readily flow due to natural buoyant forces. Unconventional reservoirs, such shale and tight gas, are those for which their characteristics (e.g. porosity, permeability) differ from conventional reservoirs. In the case of unconventional resources, additional techniques, such as hydraulic fracturing, are required to stimulate the release and flow of oil and gas from low-permeability unconventional formations such as shale. In this chapter, unconventional exploration refers to exploration that includes well completions with hydraulic fracturing.

Figure 4.2.1 **Key segments included in natural gas and petroleum systems. For detailed description of each segment, please see 4.2.2.3, Choice of Emission Factors, below.**



1366 **Figure 4.2.1(Continued) Key segments included in natural gas and petroleum systems. For detailed description of each segment, please see**
1367 **4.2.2.3, Choice of Emission Factors, below.**



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4.2.2 Methodological issues

MINOR UPDATES TO CLARIFY THAT FUGITIVES INCLUDES VENTING, FLARING, AND LEAKS

Fugitive emissions are a direct source of greenhouse gases due to the release of methane (CH_4) and formation carbon dioxide (CO_2) (i.e., CO_2 present in the produced oil and gas when it leaves the reservoir), plus some CO_2 and nitrous oxide (N_2O) from non-productive combustion activities (primarily waste gas flaring). In this chapter, fugitive emissions include emissions from venting, flaring, and leaks.

Venting comprises all engineered or intentional discharges of waste gas streams and process by-products to the atmosphere, including emergency discharges. These releases may occur on either a continuous or intermittent basis, and may include the following:

- Use of pressurized natural gas instead of compressed air as the supply medium for pneumatic devices (e.g., chemical injection pumps, starter motors on compressor engines and instrument control loops).
- Pressure relief and disposal of off-specification product during process upsets.
- Purging and blowdown events related to maintenance and tie-in activities.
- Disposal of off-gas streams from oil and gas treatment units (e.g., still-column off-gas from glycol dehydrators, emulsion treater overheads and stabilizer overheads).
- Gas releases from drilling, well-testing and pipeline pigging activities.
- Disposal of waste associated gas at oil production facilities and casing-head gas at heavy oil wells where there is no gas conservation, re-injection, or flaring.
- Solution gas emissions from storage tanks, evaporation losses from process sewers, API separators, dissolved air flotation units, tailings ponds and storage tanks, and biogenic gas formation from tailings ponds.
- Discharge of CO_2 extracted from the produced natural gas or produced as a process byproduct.

Some or all of the vented gas may be captured for storage or utilization. In this instance, the inventory of vented emissions should include only the net emissions to the atmosphere.

Flaring means broadly all burning of waste natural gas and hydrocarbon liquids by flares or incinerators as a disposal option rather than for the production of useful heat or energy. The decision on whether to vent or flare depends largely on the amount of gas to be disposed of and the specific circumstances (e.g., public, environmental and safety issues as well as local regulatory requirements). Normally, waste gas is only vented if it is non-odourous and non-toxic, and even then may often be flared. Flaring is most common at production, processing, upgrading and refining facilities but may occur in other segments as well. Waste gas volumes are usually vented on gas transmission systems and may be either vented or flared on gas distribution systems, depending on the circumstances and the company's policies. Sometimes fuel gas may be used to enrich a waste gas stream so it will support stable combustion during flaring. Fuel gas may also be used for other purposes where it may ultimately be vented or flared, such as purge or blanket gas and supply gas for gas-operated devices (e.g., for instrument controllers). The emissions from these types of fuel uses should be reported under the appropriate venting and flaring subcategories rather than under Category 1.A (Fuel Combustion Activities).

Formation CO_2 removed from natural gas by the sweetening units at gas processing plants and released to the atmosphere is a fugitive emission and should be reported under subcategory 1.B.2.b.iii.3. The CO_2 resulting from the production of hydrogen at refineries and heavy oil/bitumen upgraders should be reported under subcategory 1.B.2.a.iii.4. Care should be taken to ensure that the feedstock for the hydrogen plant is not also reported as fuel in these cases.

Leak emissions occur in all segments of the oil and natural gas systems and consist of unintentional (i.e., not vented or flared) emissions from equipment components such as valves, connectors, open ended lines, and flanges.

Fugitive emissions from oil and natural gas systems are often difficult to quantify accurately. This is largely due to the diversity of the industry, the large number and variety of potential emission sources, the wide variations in emission-control levels and the limited availability of emission-source data. The main emission assessment issues are:

- The use of simple production-based emission factors introduces large uncertainty;
- The application of rigorous bottom-up approaches requires expert knowledge and detailed data that may be difficult and costly to obtain;

- Measurement programmes are time consuming and very costly to perform.

It is *good practice* to involve technical representatives from the industry and others with expert knowledge in the development of the inventory for the use of technology- or practice-specific Tier 1 emission factors and/or for input on Tier 2 or 3 approaches.

4.2.2.1 CHOICE OF METHOD, DECISION TREES, TIERS

MINOR UPDATES TO IMPROVE CONSISTENCY BETWEEN SECTIONS

There are three methodological tiers for determining fugitive emissions from oil and natural gas systems, as set out in Section 4.2.2.2. It is *good practice* to disaggregate the activities into the segments in the Oil and Gas Industry (see Figure 4.2.1 in Section 4.2.1), and then evaluate the emissions separately for each of these. The methodological tier applied to each segment should be commensurate with the amount of emissions and the available resources. Consequently, it may be appropriate to apply different methodological tiers to different segments and subcategories within segments, and possibly even include actual emission measurement or monitoring results for some larger sources. The overall approach, over time, should be one of progressive refinement to address the areas of greatest uncertainty and consequence, and to capture the impact of control measures.

Figure 4.2.2 provides a general decision tree for selecting an appropriate approach for a given segment of the natural gas industry. The decision tree is intended to be applied successively to each segment within the natural gas system (e.g., gas exploration, gas production, then gas processing, then gas transmission, then gas storage, then LNG, then gas distribution, then other). Similarly, Figures 4.2.3 and 4.2.4 apply to crude oil production and transport systems, and to oil upgraders and refineries, respectively. Figure 4.2.5 applies to abandoned wells for both oil and natural gas.

The basic decision process is as follows:

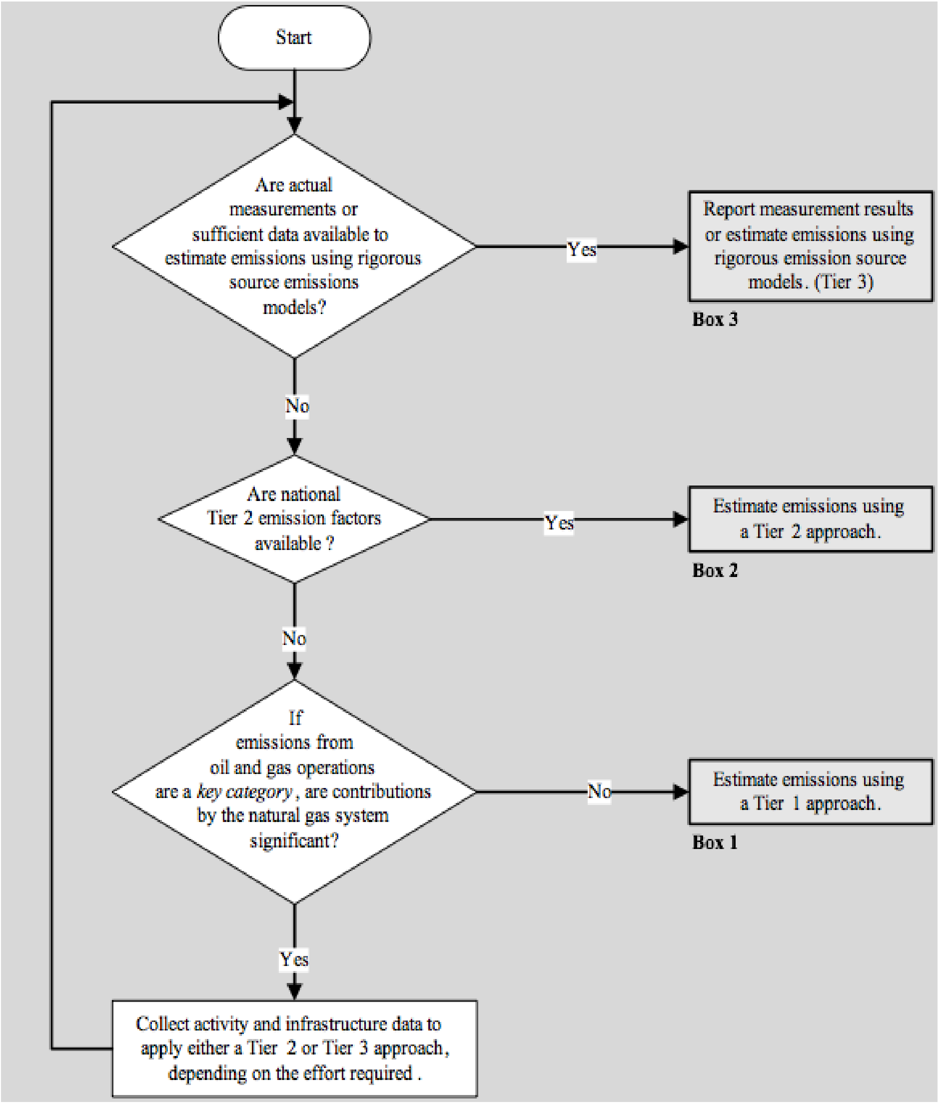
- check if the detailed data needed to apply a Tier 3 approach are readily available, and if so, then apply a Tier 3 approach (i.e., regardless of whether the category is key and the segment is significant), otherwise, if these data are not readily available:
- check if the detailed data needed to apply a Tier 2 approach are readily available, and if so, then apply a Tier 2 approach, otherwise, if these data are not readily available:
- check to see if the category is key and the specific segment being considered is significant based on the IPCC definitions of key and significant, and if so, go back and gather the data needed to apply a Tier 3 or Tier 2 approach, otherwise, if the segment is not significant:
- apply a Tier 1 approach.

The ability to use a Tier 3 approach will depend on the availability of detailed production statistics and infrastructure data (e.g., information regarding the numbers and types of facilities and the amount and type of equipment used at each site), and it may not be possible or appropriate to apply it under all circumstances. As noted above, oil and gas systems can show significant variability across regions and over time. Compilers should make efforts to ensure that emission factors are nationally and temporally appropriate. A Tier 1 approach is the simplest method to apply but is susceptible to substantial uncertainties and may easily be in error by an order-of-magnitude or more. For this reason, it should only be used as a last resort option. Where a Tier 3 approach is used in one year and the results are used to develop Tier 2 emission factors for use in other years, the applied methodologyshould be reported as Tier 2 in those other years.

Where a country has estimated fugitive emissions from oil and gas systems based on a compilation of estimates reported by individual oil and gas companies, this may either be a Tier 2 or Tier 3 approach, depending on the actual approaches applied by individual companies and facilities. In both cases, care needs to be taken to ensure there is no omitting or double counting of emissions.

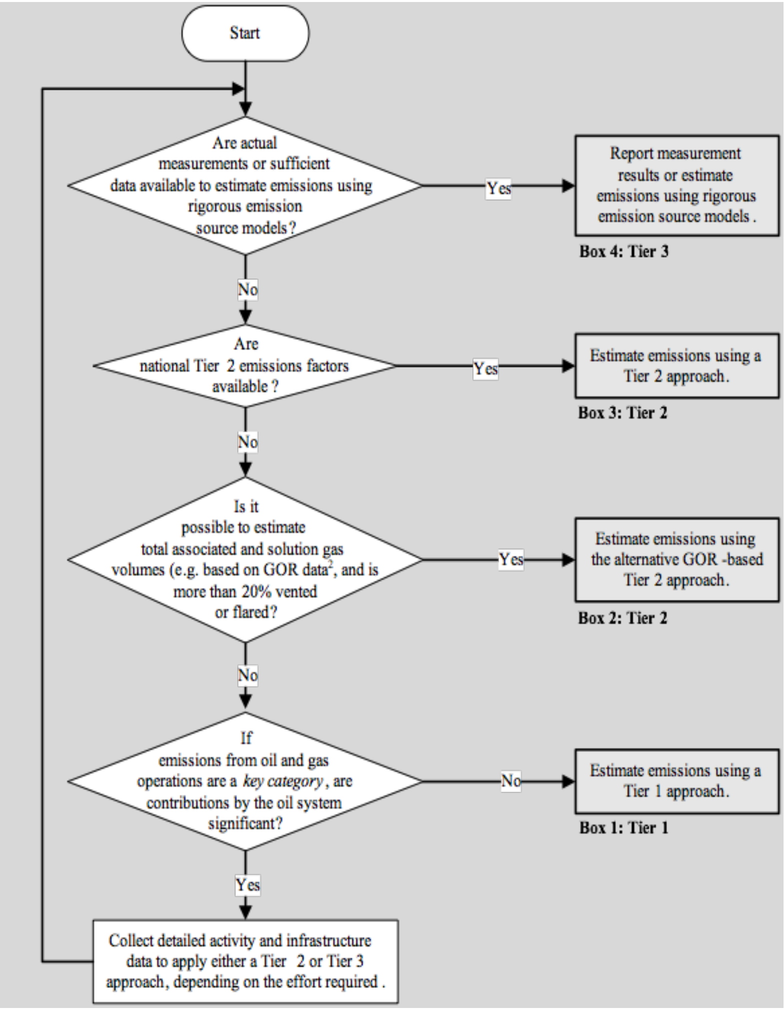
It is likely that most countries will estimate emissions from petroleum and natural gas system using a combination of tiers across and even within segments and subsegments. Tier 1 EFs disaggregated by segment are provided in Section 4.2.2.3, and additional disaggregation of those Tier 1 EFs is available in Annex 4A.2.

Figure 4.2.2 Decision tree for natural gas systems



Note: See Volume 1 Chapter 4, "Methodological Choice and Key Categories" (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

1473 **Figure 4.2.3 Decision tree for crude oil production**



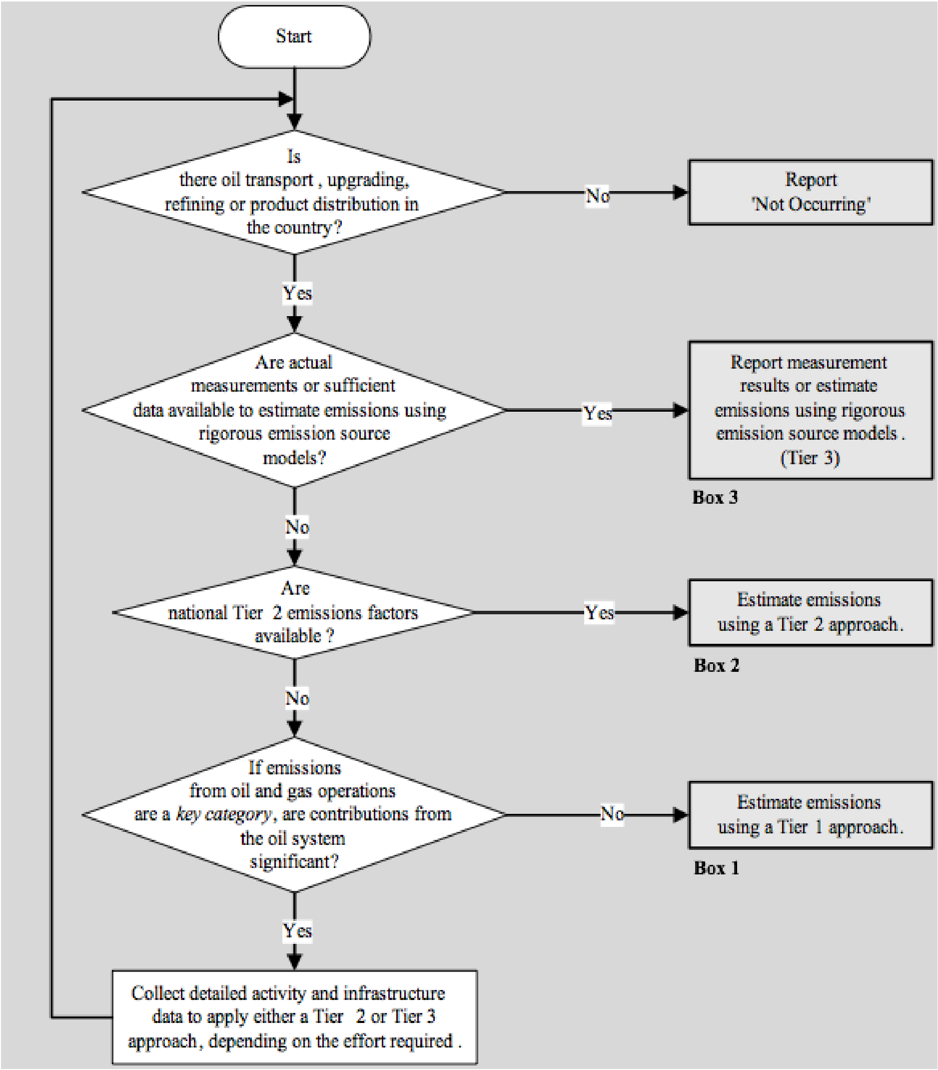
1474

1475 Note 1: See Volume 1 Chapter 4, “Methodological Choice and Key Categories” (noting section 4.1.2 on limited resources) for discussion of
1476 key categories and use of decision trees

1477 Note 2: GOR stands for gas/Oil Ratio (see Section 4.2.2.2).

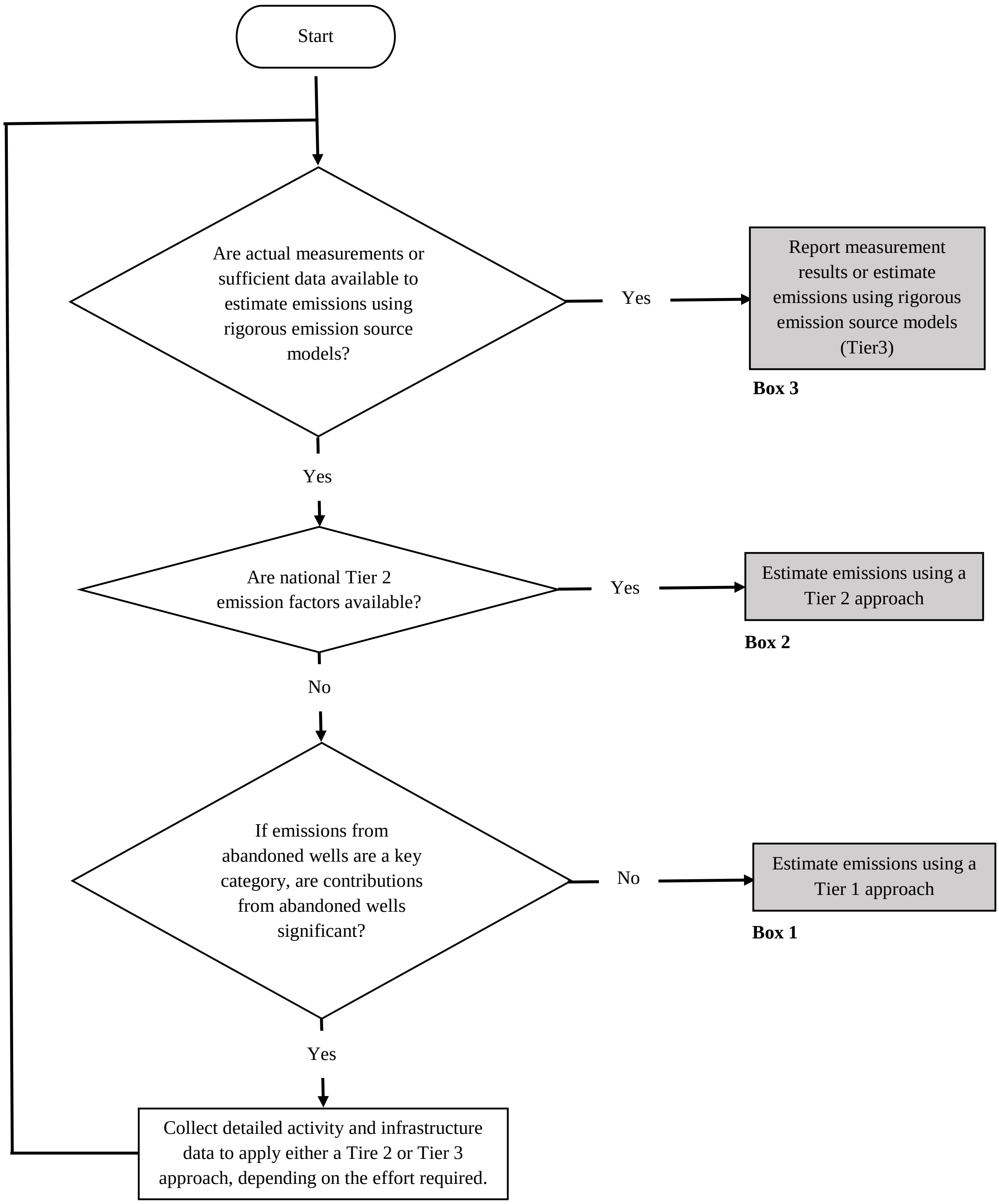
1478

Figure 4.2.4 Decision tree for crude oil transport, refining and upgrading



Note 1: See Volume 1 Chapter 4, "Methodological Choice and Key Categories" (noting section 4.1.2 on limited resources) for discussion of key categories and use of decision trees

Figure 4.2.5 Decision tree for abandoned wells ***UPDATED TO INCLUDE ABANDONED WELLS***



4.2.2.2 CHOICE OF METHOD

UPDATED TO PROVIDE BACKGROUND ON TECHNOLOGY AND PRACTICE-SPECIFIC FACTORS

The three methodological tiers for estimating fugitive emissions from oil and natural gas systems are described below.

TIER 1

Tier 1 comprises the application of appropriate default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a country's oil and natural gas industry and should only be used for non-key sources. The application of a Tier1 approach is done using Equations 4.2.1 and 4.2.2 presented below:

EQUATION 4.2.1
TIER 1: ESTIMATING FUGITIVE EMISSIONS FROM AN INDUSTRY SEGMENT

$$E_{gas,\,industry\ segment} = A_{industry\ segment} \bullet EF_{gas,\,industry\ segment}$$

EQUATION 4.2.2
TIER 1: TOTAL FUGITIVE EMISSIONS FROM INDUSTRY SEGMENTS

$$E_{gas} = \sum_{industry\ segments} E_{gas,industry\ segment}$$

Where:

$E_{gas,industry\ segement}$ = Annual emissions (tonnes)

$EF_{gas,industry\ segement}$ = emission factor (tonnes/unit of activity),

$A_{industry\ segement}$ = activity value (units of activity),

The industry segments to be considered are listed in Table 4.2.1. Not all segments will necessarily apply to all countries. For example, a country that only imports natural gas and does not produce any will probably only have gas transmission and distribution emissions. The available Tier 1 default emission factors are presented in Tables 4.2.3 through 4.2.13 in Section 4.2.2.3. Several options for activity data are available for many of the factors. For each segment, at least one factor option has been related to throughput, because production, imports and exports, and consumption are the only national oil and gas statistics that are consistently available. Throughput emission factors are applicable to throughput at standard conditions of 15°C and 101.325 kPa. For more information, see Annex 4A.1. Fugitive emissions may be more dependent on other factors. An improved basis for estimating emissions for many sources would use other activity data (e.g. length of pipeline). The Tables 4.2.3 through 4.2.13 in Section 4.2.2.3 provide options for emission factors to be applied to other activity data where possible, and where appropriate.

In addition, for many segments, technology- or practice-specific emission factors are available. Information on the appropriate use of each factor is included in Section 4.2.2.3 for each technology-specific factor.

Compilers are to assess which Tier 1 factors are most appropriate and should consider other sources or a more disaggregated EF (see Annex 4A.2) if the emission factors presented here are expected to vary significantly from national circumstances.

Fugitive greenhouse gas emissions from oil and gas related CO_2 capture and injection activities (e.g., acid gas injection and EOR projects involving CO_2 floods) will normally be small compared to the amount of CO_2 being injected (e.g., less than 1 percent of the injection volumes). At the Tier 1 or 2 methodology levels they are indistinguishable from fugitive greenhouse gas emissions by the associated oil and gas activities. The emission contributions from CO_2 capture and injection were included in the original data from which the presented Tier 1 factors were developed (i.e., through the inclusion of acid gas injection and EOR activities, along with conventional oil and gas activities, with consideration of CO_2 concentrations in the leaked, vented and flared natural gases, vapours and acid gases). Losses from CO_2 capture should be accounted for in the industry where capture occurs, while losses from, transport, injection and storage activities are assessed separately in Chapter 5.

TABLE 4.2.1
MAJOR CATEGORIES AND SUBCATEGORIES IN THE OIL AND GAS INDUSTRY

TABLE UPDATED TO INCLUDE UNCONVENTIONAL EXPLORATION AND ABANDONED WELLS, AND TO IMPROVE CLARITY

Industry Segment	Activities/Emission Sources
Gas Exploration	Includes well drilling, well testing, and well completions in both conventional and unconventional formations.
Gas Production	Dry Gas[a]
	Coal Bed Methane (Primary and Enhanced Production)
	Other enhanced gas recovery
	Sweet Gas[b]
	Sour Gas[c]
Gas Processing	Sweet Gas Plants
	Sour Gas or Acid Gas Removal Plants
	Deep-cut Extraction Plants[d]
Gas Transmission	Pipeline Systems, compressor stations
Gas Storage	Storage Facilities
Liquefied Natural Gas	Import stations, export stations, storage stations
Gas Distribution	Pipelines
	Metering and regulating stations, consumer appliances
Other	Anomalous leak events can occur across natural gas systems. Examples of such events include leakage of storage wells, emergency pressure releases, and unintentional gas spills (e.g. after prospecting).
Abandoned Gas Wells	Unplugged and plugged wells
Oil Exploration	Includes well drilling, well testing, and well completions.
Oil Production	Light and Medium Density Crude Oil (Primary, Secondary and Tertiary Production)
	Heavy Oil (Primary and Enhanced Production)
	Crude Bitumen (Primary and Enhanced Production)
	Crude Bitumen or Heavy Oil Upgrading to Synthetic Crude Oil (From Oil Sands or Oil Shales)
Oil Transport	Marine
	Pipelines

	Tanker Trucks and Rail Cars
Oil Refining	Heavy Oil
	Conventional and Synthetic Crude Oil
Refined Product Distribution	Gasoline
	Diesel
	Aviation Fuel
	Jet Kerosene
	Gas Oil (Intermediate Refined Products)
Other	Anomalous leak events can occur across segments of Petroleum Systems
Abandoned Oil Wells	Unplugged and plugged wells

[a] Dry gas is natural gas that does not require any hydrocarbon dew-point control to meet sales gas specifications. However, it may still require treating to meet sales specifications for water and acid gas (i.e. H_2S and CO_2) content. Dry gas is usually produced from shallow (less than 1000 m deep) gas wells.

[b] Sweet gas is natural gas that does not contain any appreciable amount of H_2S (i.e. does not require any treatment to meet sales gas requirements for H_2S).

[c] Sour gas is natural gas that must be treated to satisfy sales gas restrictions on H_2S content.

[d] Deep-cut extraction plants are gas processing plants located on gas transmission systems which are used to recover residual ethane and heavier hydrocarbons present in the natural gas.

TIER 2

UPDATED TO REFLECT THAT TECHNOLOGIES AND PRACTICES CHANGE OVER TIME, CLARITY ON SPLIT BETWEEN VENTING, FLARING, AND FUGITIVES, AND INFORMATION ON GOR

Tier 2 consists of using Tier 1 equations (4.2.1 and 4.2.2) with country-specific, instead of default, emission factors. It should be applied to key categories where the use of a Tier 3 approach is not practicable. The country-specific values may be developed from studies and measurement programmes, or be derived by initially applying a Tier 3 approach and then back-calculating Tier 2 emission factors using Equations 4.2.1 and 4.2.2. For example, some countries have been applying Tier 3 approaches for particular years and have then used these results to develop Tier 2 factors for use in subsequent years until the next Tier 3 assessment is performed. In general, all emission factors (including Tier 1 and Tier 2 values) should be periodically re-affirmed or updated. The frequency at which such updates are performed shall be commensurate with the rates at which new technologies, practices, standards and other relevant factors (e.g., changes in the types of oil and gas activities, aging of the fields and facilities, etc.) are penetrating the industry. New data shall be assessed to determine whether it is actually representing different practices or if it is an additional data point to be included in the emission factor applied across all time series years. For example, a survey of operations for information on practices over time could be used. If new emission factors developed in this manner account for real changes within the industry, they should not be applied backwards through the time series.

An alternative Tier 2 approach that may be applied to estimate the amount of venting and flaring emissions from the production segment of oil systems consists of performing a mass balance using country-specific production volumes, gas-to-oil ratios (GORs), gas compositions and information regarding the level of gas conservation. This approach may be applied using equations 4.2.3 to 4.2.8 below and is appropriate where reliable venting and flaring values are unavailable but representative GOR data can be obtained and venting and flaring emissions are expected to be the dominant sources of fugitive emissions (i.e., most of the associated gas production is not being captured/conserved or utilized). Under these circumstances, the alternative Tier 2 approach may also be used to estimate fugitive greenhouse gas emissions from EOR activities provided representative associated gas and vapour analyses are available and contributions due to fugitive emissions from the CO_2 transport and injection systems are small in comparison (as would normally be expected). Where the alternative Tier 2 approach is applied, any reported venting or flaring data that may be available for the target sources should not also be accounted for as this would result in double counting. However, it is good practice to compare the estimated gas vented and flared volumes determined using the GOR data to the available reported vented and flared data to identify and resolve any potential anomalies (i.e., the calculated volumes should be comparable to the available reported data, or greater if these latter data are believed to be incomplete). In the case that Tier 2 vented and flared data are applied for certain segments, leak emissions should be calculated separately using other data, for example, disaggregated Tier 1 emissions factors (see Annex 4A.2)

Table 4.2.2 shows examples of typical GOR values for oil wells from selected locations. Actual GOR values may vary from 0 to very high values depending on the local geology, state of the producing reservoir and the rate of production. Notwithstanding this, average GOR values for large numbers of oil wells tend to be more predictable. A review of limited data for a number of countries and regions indicates that average GOR values for conventional oil production would usually be in the range of about 100 to 350 m3/m3, depending on the location. When country-specific GORs are used, care should be taken to ensure that GOR measurements are performed with enough frequency to ensure representative results.

TABLE 4.2.2
TYPICAL RANGES OF GAS-TO-OIL RATIOS FOR DIFFERENT TYPES OF PRODUCTION

Type of Crude Oil Production	**Location**	**Typical GOR Values (m^3/m^3)**	
		Range[6]	**Average**
Conventional Oil	Alaska (Prudhoe Bay)	142 to 6234[2, 3]	NA
	Canada	0 to 2,000+ [1,2]	Not Available (NA)
	Qatar (Onshore, 1 Oil Field)	167 to 184[4]	173
	Qatar (Offshore, 3 Oil Fields)	316 to 386[4]	333
Primary Heavy Oil	Canada	0 to 325+ [1,5]	NA
Thermal Heavy Oil	Canada	0 to 90[1]	NA
Crude Bitumen	Canada	0 to 20[1]	NA

[1] Source: Based on unpublished data for a selection of wells in Canada.

[2] Appreciably higher GOR values may occur, but these wells are normally either classified as gas wells or there is a significant gas cap present and the gas would normally be reinjected until all the recoverable oil had been produced.

[3] Source: Mohaghegh, S.D., L.A. Hutchins and C.D. Sisk. 2002. Prudhoe Bay Oil Production Optimization: Using Virtual intelligence Techniques, Stage One: Neural Model Building. Presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 29 September–2 October 2002.

[4] Source: Corporate HSE, Qatar Petroleum, Qatar-Doha 2004.

[5] Values as high as 7,160 m^3/m^3 have been observed for some wells where there is a significant gas cap present. Gas reinjection is not done in these applications. The gas is conserved, vented or flared.

[6] Referenced at standard conditions of 15°C and 101.325 kPa.

To apply a mass balance method in the alternative Tier 2 approach, it is necessary to consider the fate of all of the produced gas and vapour. This is done, in part, through the application of a conservation efficiency (CE) factor which expresses the amount of the produced gas and vapour that is captured and used for fuel, produced into gas gathering systems or re-injected. A CE value of 1.0 means all gas is conserved, utilized or re-injected and a value of 0 means all of the gas is either vented or flared. Values may be expected to range from about 0.1 to 0.95. The lower limit applies where only process fuel is drawn from the produced gas and the rest is vented or flared. A value of 0.95 reflects circumstances where there is, generally, good access to gas gathering systems and local regulations emphasize vent and flare gas reduction.

EQUATION 4.2.3
ALTERNATIVE TIER 2 APPROACH (EMISSIONS DUE TO VENTING)

$$E_{gas,oil\ prod,venting} = GOR \bullet Q_{OIL} \bullet (1-CE) \bullet (1-X_{Flared}) \bullet M_{gas} \bullet y_{gas} \bullet 42.3\times10^{-6}$$

EQUATION 4.2.4
ALTERNATIVE TIER 2 APPROACH (CH_4 EMISSIONS DUE TO FLARING)

$$E_{CH4,oil\ prod,flaring} = GOR \bullet Q_{OIL} \bullet (1-CE) \bullet X_{Flared} \bullet (1-FE) \bullet M_{CH4} \bullet y_{CH4} \bullet 42.3\times10^{-6}$$

EQUATION 4.2.5
ALTERNATIVE TIER 2 APPROACH (CO_2 EMISSIONS DUE TO FLARING)

$$E_{CO2,\ oilprod,\ flaring} = GOR \bullet Q_{OIL} \bullet (1 - CE) \bullet X_{Flared} \bullet M_{CO2} \bullet \left[y_{CO2} + (Nc_{CH4} \bullet y_{CH4} + Nc_{NMVOC} \bullet y_{NMVOC})(1 - X_{Soot}) \right] \bullet 4.23x10^{-6}$$

EQUATION 4.2.6
CH_4 EMISSIONS FROM FLARING AND VENTING

$$E_{CH4,oil\ prod} = E_{CH4,oil\ prod,venting} + E_{CH4,oil\ prod,flaring}$$

EQUATION 4.2.7
CO_2 EMISSIONS FROM VENTING AND FLARING

$$E_{CO2,oil\ prod} = E_{CO2,oil\ prod,venting} + E_{CO2,oil\ prod,flaring}$$

EQUATION 4.2.8
N_2O EMISSIONS FROM FLARING

$$E_{N2O,oil\ prod,flaring} = GOR \bullet Q_{OIL}(1 - CE) X_{Flared} EF_{N2O}$$

Where:

$E_{i,\ oil\ prod,\ venting}$ = Direct amount (Gg/y) of GHG gas *i* emitted due to venting at oil production facilities.

$E_{i,\ oil\ prod,\ flaring}$ = Direct amount (Gg/y) of GHG gas *i* emitted due to flaring at oil production facilities.

GOR = Average gas-to-oil ratio (m^3/m^3) referenced at 15ºC and 101.325 kPa.

Q_{OIL} = Total annual oil production ($10^3\ m^3/y$).

M_{gas} = Molecular weight of the gas of interest (e.g., 16.043 for CH_4 and 44.011 for CO_2).

$N_{C,i}$ = Number of moles of carbon per mole of compound *i* (i.e., 1 for CH_4, 2 for C_2H_6, 3 for C_3H_8, 1 for CO_2, 2.1 to 2.7 for the NMVOC fraction in natural gas and 4.6 for the NMVOC fraction of crude oil vapours)

y_i = Mol or volume fraction of the associated gas that is composed of substance i (i.e., CH_4, CO_2 or NMVOC).

CE = Gas conservation efficiency factor.

X_{Flared} = Fraction of the waste gas that is flared rather than vented. With the exception of primary heavy oil wells, usually most of the waste gas is flared.

FE = flaring destruction efficiency (i.e., fraction of the gas that leaves the flare partially or fully burned). Typically, a value of 0.995 is assumed for flares at refineries and a value 0.98 is assumed for those used at production and processing facilities.

X_{soot} = fraction of the non-CO_2 carbon in the input waste gas stream that is converted to soot or particulate matter during flaring. In the absence of any applicable data this value may be assumed to be 0 as a conservative approximation.

EF_{N2O} = emission factor for N_2O from flaring ($Gg/10^3\ m^3$ of associated gas flared). Refer to the IPCC emission factor database (EFDB), manufacturer's data or other appropriate sources for the value of this factor.

$42.3x10^{-6}$ = is the number of kmol per m^3 of gas referenced at 101.325 kPa and 15ºC (i.e. $42.3x10^{-3}$ $kmol/m^3$) times a unit conversion factor of 10^{-3} Gg/Mg which brings the results of each applicable equation to units of Gg/y.

The values of $E_{CH4,\ oil\ prod,\ venting}$ and $E_{CO2,\ oil\ prod,\ venting}$ in Equations 4.2.6 and 4.2.7 are estimated using Equation 4.2.3.

It should be noted that Equation 4.2.5 accounts for emissions of CO_2 using a similar approach to what is done for fuel combustion in Section 1.3 of the Introduction chapter of the Energy Volume. The term yCO_2 in this equation effectively accounts for the amount of raw (or formation CO_2) present in the waste gas being flared. The terms $NcCH_4 \bullet yCH_4$ and $NcNMVOC \bullet yNMVOC$ in Equation 4.2.5 account for the amount of CO_2 produced per unit of CH_4 and NMVOC oxidized.

TIER 3

Tier 3 comprises the application of a rigorous bottom-up assessment by primary type of source (e.g., venting, flaring, equipment leaks, evaporation losses and accidental releases) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. It should be used for key categories where the necessary activity and infrastructure data are readily available or are reasonable to obtain. Tier 3 should also be used to estimate emissions from surface facilities where EOR, EGR and ECBM are being used in association with CCS. Approaches that estimate emissions at a less disaggregated level than this (e.g., relate emissions to the number of facilities or the amount of throughput) are deemed to be equivalent to a Tier 1 approach if the applied factors are taken from the general literature, or a Tier 2 approach if they are country-specific values.

The key types of data that would be utilized in a Tier 3 assessment would include the following:

- Facility inventory, including an assessment of the type and amount of equipment or process units at each facility, and major emission controls (e.g., vapour recovery, waste gas incineration, etc.).
- Inventory of wells and minor field installations (e.g., field dehydrators, line heaters, well site metering, etc.).
- Country-specific flare, vent and process gas analyses for each subcategory.
- Facility-level acid gas production, analyses and disposition data.
- Reported atmospheric releases due to well blow-outs and pipeline ruptures.
- Country-specific emission factors for fugitive equipment leaks, unaccounted/unreported venting and flaring, flashing losses at production facilities, evaporation losses, etc.
- The amount and composition of acid gas that is injected into secure underground formations for disposal.

Oil and gas projects that involve CO_2 injection as a means of enhancing production (e.g., EOR, EGR and ECBM projects) or as a disposal option (e.g., acid gas injection at sour gas processing plants) should distinguish between the CO_2 capture, transport, injection and sequestering part of the project, and the oil and gas production portion of the project. The net amount of CO_2 sequestered and the fugitive emissions from the CO_2 systems should be determined based on the criteria specified in Chapter 5 for CO_2 capture and storage. Any fugitive emissions from the oil and gas systems in these projects should be assessed based on the guidance provided here in Chapter 4 and will exhibit increasing concentrations of CO_2 over time in the emitted natural gas and hydrocarbon vapours. Accordingly, the applied emission factors may need to be periodically updated to account for this fact. Also, care should be taken to ensure that proper total accounting of all CO_2 between the two portions of the project occurs.

4.2.2.3 CHOICE OF EMISSION FACTOR

UPDATED TO REFLECT THE LATEST DATA, INCLUDING INFORMATION ON UPDATED PRACTICES, INCLUDING ABANDONED WELLS, AND MORE DETAILED DESCRIPTIONS OF EACH SEGMENT

Oil and gas technologies and practices and therefore, emissions, can vary greatly from country to country and over time. The level of available data also varies. Tier 1 emission factors are listed in tables below by segment. Tier 2 and 3 emission factors are also discussed below. It is likely that many countries will use a combination of tiers to calculate emissions across petroleum and natural gas systems.

TIER 1

Tier 1 default emission factors for each segment of oil and natural gas systems are presented in tables below.

Several options for activity data are available for many of the factors. For each segment, at least one factor option has been related to throughput, because production, imports and exports, and consumption are the only national oil and gas statistics that are consistently available. However, fugitive emissions may be more dependent on other factors. An improved basis for estimating emissions for many sources would use other activity data (e.g. length of pipeline). The tables in Section 4.2.2.3 provide options for emission factors to be applied to other activity data where possible, and where appropriate. In addition, for many segments, technology- or practice-specific emission factors are available. Information on the appropriate use of each factor is included for each technology-specific factor. Compilers are to assess which Tier 1 factors are most appropriate and should consider other sources or a more disaggregated EF (see Annex 4A.2) if the emission factors presented here are expected to vary significantly from national circumstances.

CH_4, CO_2, and in some cases, N_2O factors have been updated in the *2019 Refinement*. The NMVOC have not been updated, and the tables below retain the *2006 IPCC guidelines* values. Updated values consistent with 2019 values for CH_4 could be developed by inventory compilers using CH_4 emission factors from the tables and NMVOC content estimates, for example buy assuming that for crude oil the ratio of NMVOC to CH_4 is 9:1, and that natural gas has an NMVOC content of 2.5%.

It should be noted that the default EFs listed in Tables 4.2.3 to 4.2.13 are sensitive to temperature and pressure. Activity data must be consistent with the EFs standard conditions. For more information, please see Annex 4A.1.

***Note to reviewers: Some of the underlying data sets used to develop emission factors presented here may be updated after the release of the FOD. Emission factors developed from those data sets may be recalculated to reflect the latest information. ***

Oil Systems

1 B 2 a iii 1 *Exploration.*

This segment includes fugitive emissions (including equipment leaks, venting and flaring) from oil well drilling, drill stem testing and well completions. In the table below, several options for emission factors are presented. The extent of any hydraulic fracturing activities in the country should be assessed. Unconventional completions (i.e., conducted with hydraulic fracturing) have a different emissions profile than conventional completions (i.e., completed without hydraulic fracturing). This is reflected in the emission factors below. Where possible, the compiler should separate national activity data into conventional and unconventional categories and apply the relevant emission factors. Unconventional oil exploration refers to exploration where hydraulic fracturing well completion practices are used. Conventional oil exploration emission factors should be applied where hydraulic fracturing well completion practices are not used. Unconventional factors are to be applied to the unconventional activity data basis. Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is not practiced, or where the extent of flaring or recovery practices is unknown, the first set of factors should be used. Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is used, the fraction of the relevant activity data (i.e. unconventional wells drilled, total unconventional well population, or unconventional production) that uses flaring and/or gas recovery should be determined. The second set of factors is used for that fraction, while the first set of factors is applied to the wells or production that are not using flaring or recovery. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. Conventional factors (third set of factors) are to be applied to the conventional activity data basis.

Activity data options are wells drilled, total well counts, and oil production. The count of wells drilled is thought to best reflect emissions from exploration and if available should be applied. If only total oil wells or total oil production data are available, the compiler should develop an estimate of the annual split between conventional and unconventional wells or production in the country to develop the activity data. Completion rate (i.e., completions per wells drilled) impacts emissions from exploration. If completion rate information is available, the compiler could adjust the emission factors below using information from Annex 4A.2.

For each category/subcategory listed in Table 4.2.3 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$\boldsymbol{E}_{\textbf{exploration}} = \boldsymbol{A}_{\textbf{unconventional oil without flaring or recovery}} \times \boldsymbol{EF}_{\textbf{unconventional oil without flaring or recovery}} + \boldsymbol{A}_{\textbf{unconventional oil with flaring or recovery}} \times \boldsymbol{EF}_{\textbf{unconventional oil with flaring or recovery}} + \boldsymbol{A}_{\textbf{conventional oil}} \times \boldsymbol{EF}_{\textbf{conventional oil}}$$

TABLE 4.2.3 TIER 1 EMISSION FACTORS FOR OIL EXPLORATION, 1.B.2.A.III.1											
Category	**Sub-category**	**Emission source**	**CH_4**		**CO_2**		**NMVOC**		**N_2O**		**Units of measure**
			Value	**Uncertainty (% of value)**	**Value**	**Uncertainty (% of Value)**	**Value**	**Uncertainty (% of value)**	**Value**	**Uncertainty (% of value)**	

Oil exploration	Unconventional without flaring[a,d]	All	TBD	TBD	TBD	TBD	NA	NA	NA	NA	Tonnes/unconventional oil wells drilled
			0.34	TBD	0.02	TBD	NA	NA	NA	NA	Tonnes/total unconventional oil well population
			1.47	TBD	0.09	TBD	29.87-495.00	-12.5 to +800%	0.07-1.10	-10 to +1000%	Tonnes/thousand cubic meters onshore unconventional oil production
Oil exploration	Unconventional with flaring[b,d]	All	TBD	TBD	TBD	TBD	NA	NA	NA	NA	Tonnes/unconventional oil wells drilled
			0.002	TBD	0.002	TBD	NA	NA	NA	NA	Tonnes/total unconventional oil well population
			0.036	TBD	0.032	TBD	29.87-495.00	-12.5 to +800%	0.07-1.10	-10 to +1000%	Tonnes/thousand cubic meters onshore unconventional oil production
Oil exploration	Conventional[c]	All	TBD	TBD	TBD	TBD	NA	NA	NA	NA	Tonnes/conventional oil wells drilled
			0.00147	TBD	0.00003	TBD	NA	NA	NA	NA	Tonnes/total conventional oil well population
			0.00309	TBD	0.00006	TBD	29.87-495.00	-12.5 to +800%	0.07-1.10	-10 to +1000%	Tonnes/thousand cubic meters onshore conventional oil production

NA – Not Applicable, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. Emission factors for CH_4 and CO_2 developed from an EPA analysis (2015) for unconventional completions, and Radian/API, Global Emissions of Methane from Petroleum Sources (1992), for drilling emissions, as applied in the 2017 U.S. GHG Inventory; factor is an average of 2003-2007 calculated implied emission factors for emissions from well drilling, and from well completions with hydraulic fracturing that do not flare or use gas capture. NMVOC and N_2O values are from IPCC 2006 GL, for exploration, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

b. Emission factors for CH_4 and CO_2 developed from an EPA analysis (2015) for unconventional completions, and from Radian/API, Global Emissions of Methane from Petroleum Sources (1992), for drilling emissions, as applied in the 2017 U.S. GHG Inventory. Factor is the average of 2011-2015 calculated implied emission factors for emissions from well drilling, and from well completions with hydraulic fracturing that flare or use gas capture. NMVOC and N_2O values are from IPCC 2006 GL, for exploration, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

c. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996) for conventional completions, and Radian/API, Global Emissions of Methane from Petroleum Sources (1992), for drilling emissions, as applied in the 2017 U.S. GHG Inventory. Factor is the average of 2003-2015 calculated implied emission factors for emissions from well drilling and from conventional completions. NMVOC and N_2O values are from IPCC 2006 GL for exploration, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

d. Unconventional gas exploration refers to exploration that includes well completions with hydraulic fracturing. Conventional Gas exploration emission factors should be applied where hydraulic fracturing well completion practices are not used.

1 B 2 a iii 2 Production and Upgrading

This segment includes fugitive emissions from oil production (including leaks, venting, and flaring) from the oil wellhead or at the oil sands or shale oil mine through to the start of the oil transmission system. Emissions arise from the wells themselves (e.g., as wellhead leaks and from well workovers), and well-site equipment such as pneumatic controllers, dehydrators and separators. This includes fugitive emissions related to oil sands or shale oil mining, transport of untreated production (i.e , well effluent, emulsion, oil shale and oil sands) to treating or extraction facilities, activities at extraction and upgrading facilities, associated gas re-injection systems and produced water disposal systems. Fugitive emissions from upgraders are grouped with those from production rather than those from refining since the major product from upgraders (i.e. synthetic crude oil) requires further processing at refineries. Upgraders are often integrated with extraction facilities and may also be integrated with refineries, co-generation plants or other industrial facilities, making their relative contributions difficult to establish.

The table below presents factors for onshore oil production, and offshore oil production. Several options for emission factors for onshore production are presented. The types of technologies and practices in use in the country should be assessed. Where this information is unknown, or where there is limited use of lower-emitting technologies, the first set of emission factors for oil production should be used. Examples of higher-emitting technologies and practices include venting of associated gas and uncontrolled tanks. Where lower-emitting technologies are used extensively, the second set of emission factors for oil production should be used. Examples of lower-emitting technologies and practices include limited venting or flaring of associated gas, and tanks with controls. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. Emission factors are presented in units of tonne per thousand cubic meter oil produced and in tonne per active well.

Countries with onshore oil production should apply a factor for onshore production and the factor for gathering to the relevant activity data for onshore production. Countries with offshore oil production should apply a factor for offshore oil production. The emission factors for onshore production were developed from data sets that included a mix of production from wells in conventional formations and wells in unconventional formations and are considered to be applicable to both. Factors presented are inclusive of venting, flaring, and leak emissions. For cases where country-specific data are available for a subcomponent of the factor (e.g. venting and flaring emissions), disaggregated Tier 1 EF that could be applied to estimate the remaining emission types are available—see Annex 4A.2.

Oil sands are a type of unconventional petroleum deposit made of up a mixture of sand, clay, and water, saturated with a highly viscous form of petroleum called crude bitumen. Crude bitumen is an extra-heavy oil with an API gravity below 10° API. In its natural state, it is not usually recoverable at commercial rates through a well because it is too thick to flow. There are two methods that are used to recover crude bitumen, depending on the depth of the deposit. Bitumen that occurs near the surface can be recovered by open-pit mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is recovered from the mined material in large facilities using hot water and solvents. When the resource is located too deep to make surface mining economical, in situ extraction methods are utilized. In situ extraction takes place both by primary extraction methods, similar to conventional crude oil, and enhanced extraction. The two main methods of enhanced recovery are cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). Both methods use steam to heat the reservoir allowing the bitumen to flow to a vertical or horizontal wellbore. Due to the large quantities of both hot water and steam needed to extract the bitumen, co-generation plants are often co-located with the extraction facilities.

Once the bitumen is produced using surface mining or in situ methods, it can be upgraded to synthetic crude oil (SCO) or lighter hydrocarbon products at an upgrader and then transported to a refinery for further processing. Upgraders improve the quality of the crude bitumen by adding hydrogen, removing carbon, or both. During the upgrading process, most of the sulphur and other impurities are removed. The produced bitumen can also be mixed with a less viscous material (referred to as diluent), such as SCO or condensate, allowing the mixture to flow through a pipeline.

Fugitive emissions from in situ extraction include leaks, venting and flaring that occur at the well pad through to the start of the oil transmission system. Open pit mining extraction of crude bitumen also includes fugitive emissions from leaks, venting and flaring. Additional methane present in the oil sands ore is released during mining, mine dewatering, and ore transport, crushing and handling activities. Waste tailings are created during the extraction process consisting of unrecovered solvent, bitumen, water, sand, clay and other impurities. Fugitive emissions from tailings ponds occur as microbial and bacterial degradation of hydrocarbons and vegetation present at the bottom of the ponds produces methane gas. The upgrading process produces fugitive emissions of leaks, venting and flaring, including CO_2 venting from sulphur recovery operations and the hydrogen production process.

For each category/subcategory listed in Table 4.2.4 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$\boldsymbol{E}_{\boldsymbol{oil}\ \mathbf{production}} = \boldsymbol{A}_{\mathbf{onshore\ oil\ production}} \times \boldsymbol{EF}_{\mathbf{onshore\ oil\ production}} + \boldsymbol{A}_{\mathbf{offshore\ oil\ production}} \times \boldsymbol{EF}_{\mathbf{offshore\ oil\ production}}$$

TABLE 4.2.4
TIER 1 EMISSION FACTORS FOR OIL PRODUCTION, 1.B.2.A.III.2

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

Onshore Production	Most activities occurring with higher-emitting technologies and practices[a]	All	4.54	TBD	8.48	TBD	4,717-2,354,200	-100 to +800%	0.54-0.74	-10-+1000%	Tonnes/thousand cubic meters onshore oil production
			3.38	TBD	6.32	TBD	NA	NA	NA	NA	Tonnes per active oil well
Onshore Production	Most activities occurring with lower-emitting technologies and practices[b]	All	2.38	TBD	6.50	TBD	4,717-2,354,200	-100 to +800%	0.54-0.74	-10-+1000%	Tonnes/thousand cubic meters onshore oil production
			2.21	TBD	6.05	TBD	NA	NA	NA	NA	Tonnes per active oil well
Onshore production-Oil Sands	Oil Sands Mining and Ore Processing[c]	All	0.74	±29.4%	7.56	±21.5%	0.65	-26.5 to +95%	$1.1x10^{-5}$	-30 to +520%	Tonnes/thousand cubic meters crude bitumen production from surface mining
Onshore production-Oil Sands	Oil Sands Upgrading[c]	All	0.13	-34.2 to +119%	90.73	±13.4	0.07	-60.3 to +75%	2.8×10^{-4}	-22.1 to +313%	Tonnes/thousand cubic meters synthetic crude oil production
Offshore production	All[d]	All	2.36	TBD	0.10	TBD	4,717-2,354,200	-100 to +800%	0.54-0.74	-10-+1000%	Tonnes/thousand cubic meters offshore oil production

NA – Not Applicable, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), and data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted). Examples of higher-emitting technologies and practices include venting of associated gas and uncontrolled tanks. NMVOC and N_2O values are from IPCC 2006 GL, “default weighted values” for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

b. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), and EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 2015 (the most recent year of GHGRP data availability). Examples of lower-emitting technologies and practices include limited venting or flaring of associated gas, and tanks with controls. NMVOC and N_2O values are from IPCC 2006 GL, “default weighted values” for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

c. Emission factors developed from An Inventory of GHG, CAC and Other Priority Emissions by the Canadian Oil Sands Industry: 2015, prepared by Clearstone Engineering Ltd. for Environment and Climate Change Canada (2017) and production data from the Alberta Energy Regulator (AER), ST39: Alberta Mineable Oil Sands Plant Statistics.

d. Emission factors for CH_4 and CO_2 developed from U.S. Bureau of Ocean Energy Management’s (BOEM) Gulf Offshore Activity Data System (GOADS), as applied in the 2017 U.S. GHG Inventory, to estimate emissions for 2011 (the year of the most recent BOEM survey). NMVOC and N_2O values are from IPCC 2006 GL, “default weighted values” for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

1 B 2 a iii 3 Transport.

This segment includes fugitive emissions (including leaks, venting, and flaring) related to the transport of marketable crude oil (including conventional, heavy and synthetic crude oil and bitumen) to upgraders and refineries. The transportation systems may comprise pipelines, marine tankers, tank trucks and rail cars. Evaporation losses from storage, filling and unloading activities and fugitive equipment leaks are the primary sources of these emissions.

For each category/subcategory listed in Table 4.2.5 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$E_{\text{oil transport}} = A_{pipelines} \times EF_{pipelines} + A_{tanker\ trucks\ and\ rail\ cars}\ x\ EF_{tanker\ trucks\ and\ rail\ cars} + A_{marine\ tanks}\ x\ EF_{marine\ tanks}$$

TABLE 4.2.5
TIER 1 EMISSION FACTORS FOR OIL TRANSPORT, 1.B.2.A.III.3

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

Oil Transport	Pipelines[a]	All	0.0054	±100%	0.00049	±100%	0.054	-50% to +200%	NA	NA	Tonne per thousand cubic meters oil transported by pipeline
Oil Transport	Tanker Trucks and Rail Cars[b]	All	0.025	±50%	0.0023	±50%	0.25	-50% to +200%	NA	NA	Tonne per thousand cubic meters oil transported by tanker truck or rail car
Oil Transport	Tanks[c]	All	0.002	TBD	TBD	TBD	ND	ND	ND	ND	Tonne per thousand cubic meters crude oil feed
Oil Transport	Loading of offshore production on tanker ships without VRU[d]	All	0.093	TBD	TBD	TBD	ND	ND	ND	ND	Tonne per thousand cubic meters oil loaded onto tanker ship
Oil Transport	Loading of offshore production on tanker ships with VRU[e]	All	0.066	TBD	TBD	TBD	ND	ND	ND	ND	Tonne per thousand cubic meters oil loaded onto tanker ship

NA – Not Applicable, ND – Not Determined, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. From 2006 GL values for both developed and developing and economies in transition.

b. From 2006 GL values for both develop and developing and economies in transition. Note from IPCC 2006: "NMVOC values are derived from methane values based on the ratio of the mass fractions of NMVOC to CH4. Values of 0.0144 kg/kg for gas transmission and distribution, 9.951 kg/kg for oil and condensate transportation and 0.3911 kg/kg for synthetic crude oil production are used."

c. Emission factors for CH4 and CO2 developed from and Radian/API, Global Emissions of Methane from Petroleum Sources (1992), as applied in the 2017 U.S. GHG Inventory for all years. with hydraulic fracturing that do not flare or use gas capture. NMVOC and N2O values are from IPCC 2006 GL, for exploration, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

d. Emission factors for CH_4 and CO_2 developed from 2017 Norway GHG Inventory implied emission factors for 1990-2000.

e. Emission factors for CH_4 and CO_2 developed from 2017 Norway GHG Inventory implied emission factors for 2002-2015.

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1 B 2 a.iii 4. Refining

This segment includes fugitive emissions (including leaks, venting, and flaring) at petroleum refineries. Refineries process crude oils, natural gas liquids and synthetic crude oils to produce final refined products (e.g., primarily fuels and lubricants). Methane emission sources include storage tanks, blowdowns, asphalt blowing, equipment leaks, vents, loading operations, wastewater treating, cooling towers, catalytic cracking/reforming/fluid cracking, flares, delayed coking, and coke calcining. Carbon dioxide emissions included under 1.B.2.a.iii.4 include asphalt blowing, process vents, and flaring. Where refineries are integrated with other facilities (for example, upgraders or co-generation plants) their relative emission contributions can be difficult to establish in measurement studies. The emission factors below represent petroleum refinery emissions only.

TABLE 4.2.6
TIER 1 EMISSION FACTORS FOR OIL REFINING, 1.B.2.A.III.4

Category	Sub-categoryc	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Oil Refining	All[a]	All	0.084	TBD	5.848	TBD	1.3	-100 to +100%	ND	ND	Tonnes/thousand cubic meters oil refined

ND – Not Determined, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

Emission factor s for CH_4 and CO_2 developed as an average of 2018 German GHG Inventory data (1990 to 2016) with a range of 0.067 to 0.117 tonnes CH_4/thousand cubic meters and 5.437 to 6.143 tonnes CO_2/thousand cubic meters. NMVOC factor is from 2006 IPCC Guidelines, value for developed countries as no value was presented for developing and economies in transition. Note from IPCC 2006: "Estimated based on an aggregated emission factors for fugitive equipment leaks, fluid catalytic cracking and storage and handling of 0.53 kg/m^3 (CPPI and Environment Canada, 1991), 0.6 kg/m^3 (US EPA, 1995) and 0.2 g/kg (assuming the majority of the volatile products are stored in floating roof tanks with secondary seals) (EMEP/CORINAIR, 1996)."

1 B 2 a iii 5 Distribution of Oil Products

This segment includes fugitive emissions (including leaks, venting and flaring) from the transport and distribution of refined products, including those at bulk terminals and retail facilities. Evaporation losses from storage, filling and unloading activities and equipment leaks are the primary sources of these emissions. Many products are directly used in chemical industry and should be considered in the appropriate subcategory (e.g. 2.B.8). Table 4.2.7 below provides emission factors for major fuel types. The emission factors regard emissions from refinery dispatch or border dispatch stations, to depots and further distribution to end-users (e.g. gas stations and airports). It is assumed that a fractional distillation in the refinery separated gaseous components from fuels. Therefore, only NMVOC emissions factors are provided. Tier 1 emission factors are currently available for only a subset of the total types of oil products distributed.

For each category/subcategory listed in Table 4.2.7 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$E_{distribution\ of\ oil\ productions} = A_{gasoline\ distribution} \times EF_{gasoline\ distribution} + A_{other\ distribution} \times EF_{other\ distribution}$$

TABLE 4.2.7
TIER 1 EMISSION FACTORS FOR DISTRIBUTION OF OIL PRODUCTS, 1.B.2.A.III.5

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Refined Product Distribution	Gasoline[a]	All	NA	NA	NA	NA	2.2	+/-100%	NA	NA	Tonnes per thousand cubic meters product transported
Refined Product Distribution	Other (e.g. diesel, aviation fuel, jet kerosene)	All	NA	NA	NA	NA	ND	ND	NA	NA	Tonnes per thousand cubic meters product transported

NA – Not Applicable, ND – Not Determined

NMVOC factor is from 2006 IPCC Guidelines, value for developed countries as no value was presented for developing and economies in transition. Note from IPCC 2006 GL: "Estimated based on assumed average evaporation losses of 0.15 percent of throughput at the distribution terminal and additional losses of 0.15 percent of throughput at the retail outlet. These values will be much lower where Stage 1 and Stage 2 vapour recovery occurs and may be much greater in warmer climates."

1 B 2 a iii 6 Other

Fugitive emissions (including leaks, venting and flaring) from oil systems not otherwise accounted for in the above categories. This includes fugitive emissions from spills and other accidental releases, waste oil treatment facilities and oilfield waste disposal facilities.

Anomalous leak events can occur across petroleum systems and can have highly variable emissions. Examples of such events include releases from emergency pressure relieving equipment such as emergency shutdowns (ESD), emergency safety blowdowns (ESB), pressure relief valves (PRV), and breakout/surge tanks (API, 2009). It is *good practice* to quantify and report such emissions whenever possible under 1 B 2 a iii 6. There is no Tier 1 method available for such events, which need to be evaluated on a case-by-case basis, often using a combination of emission factors and engineering calculations. An example of calculating emissions during emergency conditions though an engineering calculation approach is given in the 2009 American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*.

1 B 2 a iii 7 Abandoned Oil Wells

When production activities are completed, oil and gas wells may be abandoned. Several reasons of well abandonment exist: if wells have fulfilled their purpose; after the surrender of a production license; due to geological reasons; due to technical reasons; due to technological, ecological and other reasons. Countries with a long history of oil and gas production may have a significant abandoned well population and should estimate emissions for this source.

For onshore wells ending production in recent decades, the abandonment process is often covered by national (or regional) well abandonment regulations. Regulated wells are often treated with plugging and other practices prior to abandonment/decommissioning to prevent leakage from the wells and migration of oil, gas or brine to surrounding strata. That process can be generally described as follows. The wells are plugged (with the use of plugging materials, e.g. cement) and sealed according to the regulations and considering reasons of decommissioning, geological conditions, and other well specifics. If these steps are implemented effectively and the long-term integrity of the well does not fail over time, it is unlikely that the well will leak substantial amounts of methane. However, in practice integrity failure of some abandoned wells may occur and the well may start leaking methane to the atmosphere. This is consistent with findings of recent studies in the U.S. and U.K., which have found that the majority of effectively plugged wells are not leaking, but a small number will have some emissions.

Tier 1 default emission factors are presented in Table 4.2.8. All of the presented emission factors are expressed in units of mass of emissions per abandoned well. All the EFs are developed from data for both abandoned oil and gas wells. The EFs of onshore abandoned wells are split into either “plugged” (or, properly decommissioned per regulations) and “unplugged” well categories. The distinction requires the number of each type of abandoned well (onshore plugged, onshore unplugged). If insufficient data on plugging practices is available to disaggregate activity data in such a way, the default EF for unplugged wells is to be used. More limited data are available on offshore wells and disaggregated (i.e. plugged versus unplugged) factors are not available.

Based on available data, emission factors (and leak frequency) do not vary over the time series per well; according to the latest research, well integrity failure rate shows no significant trend over time. If failures do exist, they more likely occur early on in the decommissioned life of a well (Boothroyd I.M. et al, 2006). Based on the latest research, gas well emission rates may be higher than oil well emissions rates. However, due to limited data points in the currently available data, Tier 1 EFs were not disaggregated into oil-specific and gas-specific factors. In cases where national circumstances are different from listed above, a country should consider using a Tier 2 or Tier 3 approach.

Activity data for this source are counts of abandoned onshore and offshore wells in each year of the time series, and for onshore wells, the fraction of wells that are effectively plugged. It may be challenging to compile a total national count of abandoned wells and to assess whether wells are plugged or unplugged. There is likely significant variation between post-well closure practices internationally and even within countries.

TABLE 4.2.8
TIER 1 EMISSION FACTORS FOR ABANDONED OIL WELLS, 1.B.2.A.III.7

Category	Sub-category[c]	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Abandoned wells	Plugged onshore[a]	Leaks	0.02-3.13	62.22	NA	NA	NA	NA	NA	NA	Kg CH_4/ onshore unplugged well
Abandoned wells	Unplugged, onshore[b]	Leaks	87.78-267.82	41.94	NA	NA	NA	NA	NA	NA	Kg CH_4/ onshore plugged well
Abandoned wells	Offshore[c]	Leaks	1.76-5.36	25	NA	NA	NA	NA	NA	NA	Kg CH_4/ offshore plugged well

NA – Not Applicable

a. From Kang et al. 2016 and Townsend-Small et al. 2016. The low end includes data collected from wells across the U.S.; the high end includes data collected from wells in the Appalachian basin of the U.S.

b. From Kang et al. 2016 and Townsend-Small et al. 2016. The low end includes data collected from wells across the U.S.; the high end includes data collected from wells in the Appalachian basin of the U.S.

c. Developed by using the onshore abandoned wells emission factors in this table, and applying a factor of 0.02 to reflect that most methane from such wells is dissolved in marine water. Factor of 0.02 based on Vielstädte, L., Karstens, J., Haeckel, M., Schmidt, M., Linke, P.,Reimann, S., Liebetrau, V., McGinnis, D.F., Wallmann, K., Quantification of methane emissions at abandoned gas wells in the Central North Sea, Marine and Petroleum Geology (2015), doi: 10.1016/j.marpetgeo.2015.07.030.

Natural Gas Systems

1B 2 b iii 1 Exploration

This segment includes emissions (including equipment leaks, venting and flaring) from gas well drilling, drill stem testing and well completions. In the table below, several options for emission factors are presented. The extent of any hydraulic fracturing activities in the country should be assessed. Unconventional completions (i.e., conducted with hydraulic fracturing) have a different emissions profile than conventional completions (e.g. conducted without hydraulic fracturing). This is reflected in the emission factors below. Where possible, the compiler should separate national activity data into conventional and unconventional categories and apply the relevant emission factors. Unconventional gas exploration refers to exploration that includes well completions with hydraulic fracturing. Conventional gas exploration emission factors should be applied where hydraulic fracturing well completion practices are not used. Unconventional factors are to be applied to the unconventional activity data basis. Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is not practiced, or where the extent of flaring or recovery practices is unknown, the first set of factors should be used. Where wells drilled are completed with hydraulic fracturing and flaring and gas recovery is used, the fraction of the relevant activity data (i.e. unconventional wells drilled, total unconventional well population, or unconventional production) that uses flaring and/or gas recovery should be determined. The second set of factors is used for that fraction, while the first set of factors is applied to the wells or production that is not using flaring or recovery. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. Conventional factors (third set of factors) are to be applied to the conventional activity data basis. Activity data options are wells drilled, total well counts, and gas production. The count of wells drilled is thought to best reflect emissions from exploration and if available should be applied. If only total gas wells or total gas production data are available, the compiler should develop an estimate of the annual split between conventional and unconventional wells or production in the country to develop the activity data. Completion rate (i.e., completions per wells drilled) impacts emissions from exploration. If completion rate information is available, the compiler could adjust the emission factors below using information from Annex 4A.2. For each category/subcategory listed in Table 4.2.9 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$\boldsymbol{E}_{\text{exploration}} = \boldsymbol{A}_{\text{unconventional gas without flaring or recovery}} \times \boldsymbol{EF}_{\text{unconventional gas without flaring or recovery}} + \boldsymbol{A}_{\text{unconventional gas with flaring or recovery}} \times \boldsymbol{EF}_{\text{unconventional gas with flaring or recovery}} + \boldsymbol{A}_{\text{conventional gas}} \times \boldsymbol{EF}_{\text{conventional gas}}$$

TABLE 4.2.9
TIER 1 EMISSION FACTORS FOR NATURAL GAS EXPLORATION SEGMENT, 1.B.2.B.III.1

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

Gas Exploration	Unconventional gas exploration without flaring or gas capture[a, d]	All	TBD	TBD	TBD	TBD	NA	NA	NA	NA	Tonnes/new gas wells drilled in unconventional formations
			8.91	TBD	2.08	TBD	29.87-495.00	-12.5 to +800%	0.07-1.10	-10 to +1000 %	Tonnes/million cubic meters onshore unconventional gas production
			5.56	TBD	1.28	TBD	NA	NA	NA	NA	Tonnes/total gas wells in unconventional formations
Gas Exploration	Unconventional gas exploration with flaring or gas capture[b, d]	All	TBD	TBD	TBD	TBD	NA	NA	NA	NA	Tonnes/new gas wells drilled in unconventional formations
			0.11	TBD	0.19	TBD	29.87-495.00	-12.5 to +800%	0.07-1.10	-10 to +1000 %	Tonnes/million cubic meters onshore unconventional gas production
			0.15	TBD	0.28	TBD	NA	NA	NA	NA	Tonnes/total gas wells in unconventional formations
Gas Exploration	Conventional Gas exploration[c]	All	TBD	TBD	TBD	TBD	NA	NA	NA	NA	Tonnes/new gas wells drilled in conventional formations
			0.00243	TBD	0.00026	TBD	29.87-495.00	-12.5 to +800%	0.07-1.10	-10 to +1000 %	Tonnes/million cubic meters onshore conventional gas production
			0.00505	TBD	0.00053	TBD	NA	NA	NA	NA	Tonnes/total gas wells in conventional formations

NA – Not Applicable, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP) for unconventional completions, and Radian/API, Global Emissions of Methane from Petroleum Sources (1992), for drilling emissions, as applied in the 2017 U.S. GHG Inventory. Factor is the average of 2006-2010 calculated implied emission factors for emissions from well drilling, and from well completions with hydraulic fracturing that do not flare or use gas capture. NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

b. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP) for unconventional completions, and from Radian/API, Global Emissions of Methane from Petroleum Sources (1992), for drilling emissions, as applied in the 2017 U.S. GHG Inventory. Factor is the average of 2013-2015 calculated implied emission factors for emissions from well drilling, and from well completions with hydraulic fracturing that flare or use gas capture. NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

c. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996) for conventional completions, and Radian/API, Global Emissions of Methane from Petroleum Sources (1992), for drilling emissions. Factor is the average of 2006-2010 calculated implied emission factors for emissions from well drilling and from conventional completions. NMVOC and N2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

d. Unconventional gas exploration refers to exploration that includes well completions with hydraulic fracturing. Conventional gas exploration emission factors should be applied where hydraulic fracturing well completion practices are not used.

1B 2 b iii 2 Production and Gathering

This segment includes fugitive emissions (including leaks, venting and flaring) from the gas wellhead through to the inlet of gas processing plants, or, where processing is not required, to the tie-in points on gas transmission systems. In the production stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves (e.g., as wellhead leaks and from well workovers), and well-site equipment such as pneumatic controllers, dehydrators and separators. Gathering and boosting emission sources are included within the production sector. The gathering and boosting sources include gathering and boosting stations (with multiple emission sources on site, such as pneumatic controllers and tanks) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines or processing facilities (custody transfer points are typically used to segregate sources between each segment).

The table below presents factors for onshore gas production, gathering systems, and offshore gas production. Several options for emission factors for onshore production are presented. The types of technologies and practices in use in the country should be assessed. Where this information is unknown, or where there is limited use of lower-emitting technologies, the first set of emission factors for gas production should be used. Examples of higher-emitting technologies and practices include venting for liquids unloading without plunger lifts, unconventional workovers that vent, and use of high-bleed pneumatic controllers. Where lower-emitting technologies are used extensively, the second set of emission factors for gas production should be used. Examples of lower-emitting technologies and practices include venting for liquids unloading with plunger lifts, unconventional workovers using reduced emission completion technologies, and low-bleed pneumatic controllers. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. In case of lack of data disaggregated on offshore and onshore gas production it is recommended to disaggregate volumes of gas produced according to the data on share of onshore/offshore production, if available. If no data are available to estimate the share of onshore versus offshore production, EF for onshore production should be applied to the total quantity of gas production. Emission factors are presented in units of tonne per million cubic meter gas produced and in tonne per active well.

Countries with onshore gas production should apply a factor for onshore production and the factor for gathering to the quantity of onshore gas produced in each year. Countries with offshore gas production should apply a factor for offshore gas production. The emission factors for onshore production were developed from data sets that included a mix of production from wells in conventional formations and wells in unconventional formations and are considered to be applicable to both. If data on coal bed methane production are available, the factor for coal bed methane production may be applied to the portion of gas production that is from coal bed methane. Factors presented are inclusive of venting, flaring, and leak emissions. For cases where country-specific data are available for a subcomponent for the factor (e.g. venting and flaring emissions using the GOR method discussed in Section 4.2.2.2), disaggregated Tier 1 EF are available in Annex 4A.2.

For each category/subcategory listed in Table 4.2.10 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$E_{\textbf{production}} = A_{\textbf{onshore gas production}} \times EF_{\textbf{onshore gas production}} + A_{\textbf{gathering}} \times EF_{\textbf{gathering}} + A_{\textbf{offshore gas production}} \times EF_{\textbf{offshore gas production}}$$

TABLE 4.2.10
TIER 1 EMISSION FACTORS FOR NATURAL GAS PRODUCTION SEGMENT, 1.B.2.B.III.2

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

Onshore Production	Most activities occurring with higher-emitting technologies and practices[a]	All	3.97	TBD	27.45	TBD	1,200.85	-75 to + 250%	0.02-0.03	-10 to +1000%	Tonnes/million cubic meters onshore gas production
			6.87	TBD	47.56	TBD	NA	NA	NA	NA	Tonnes/active gas well
Onshore Production	Most activities occurring with lower-emitting technologies and practices[b]	All	2.45	TBD	24.76	TBD	1,200.85	-75 to + 250%	0.02-0.03	-10 to +1000%	Tonnes/million cubic meters onshore gas production
			4.21	TBD	42.49	TBD	NA	NA	NA	NA	Tonnes per active gas well
Onshore Production – Coal Bed Methane	All[c]	All	0.95	TBD	42.60	TBD	1,200.85	-75 to + 250%	0.02-0.03	-10 to +1000%	Tonnes/million cubic meters onshore gas production
Gathering	All[d]	All	3.21	TBD	0.34	TBD	NA	NA	NA	NA	Tonnes/million cubic meters onshore gas production
Offshore production	All[e]	All	2.74	TBD	6.84	TBD	91.62	-75 to + 250%	0.02-0.03	-10 to +1000%	Tonnes/million cubic meters offshore gas production

NA – Not Applicable, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), and data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted). Examples of higher-emitting technologies and practices include venting for liquids unloading without plunger lifts, unconventional workovers that vent, and use of high-bleed pneumatic controllers. NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

b. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), and data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 2015 (the most recent year of GHGRP data availability). Examples of lower-emitting technologies and practices include venting for liquids unloading with plunger lifts, unconventional workovers using reduced emission completion technologies, and low-bleed pneumatic controllers. NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

c. Emission factors for CH_4 and CO_2 developed from data reported to the Australian National Greenhouse and Energy Reporting program (NGER), as applied in the 2017 Australian National Inventory to calculate emissions for the financial years 2014-17.

d. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), and Marchese et al. 2015, as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 2012 (when the measurements used in Marchese were conducted). NMVOC and N_2O values from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

e. Emission factor s for CH_4 and CO_2 developed from U.S. Bureau of Ocean Energy Management's (BOEM) Gulf Offshore Activity Data System (GOADS), as applied in the 2017 U.S. GHG Inventory, to estimate emissions for 2011 (the year of the most recent BOEM survey). NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

1 B 2 b iii 3 Processing

This segment includes fugitive emissions (including leaks, venting and flaring) from gas processing facilities. In this stage, natural gas liquids (NGLs) and various other constituents (e.g. sulfur) from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Emission sources include compressors, equipment leaks, pneumatic controllers, uncombusted methane from engines and flaring, and CO_2 from flaring and sour gas removal. In the Table 4.2.11 below, several options for emission factors are presented. The extent of any leak detection and repair (LDAR) programs in the country should be assessed. Where this information is unknown, or where there are limited or no LDAR programs, the "without LDAR" emission factors for Gas Processing should be used. Where leak detection and repair programs are in use, use the "with LDAR" emission factors for Gas Processing. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. Where sour gas (or "acid gas") removal is occurring, the factor for that source should also be applied to the portion of gas processed with sour gas removal, and added to the overall gas processing total. Emission factors are presented in both units of tonnes per million cubic meter gas processed and million cubic meters gas produced. Information for disaggregating the Tier 1 EFs is available in Annex 4A.2.

The emissions from gas processing ($E_{processing}$) are computed by multiplying the appropriate emission factor from Table 4.2.11 by the amount of gas processed (units of millions of cubic meter of gas). If sour gas is removed, this emission should be added to the overall processing emissions, where the emissions from sour gas removal is computed as the product of the emission factor for sour gas removal from Table 4.2.11 and the amount of sour gas that is processed (in units of millions of cubic meters of sour gas). The compiler should attempt to determine the fraction of the gas processed that is sour gas using nationally available statistics or industry information on the characteristics of processing plants. If no data is available, it is good practice to assume the fraction, for example by considering the study of Burgers et al 2011[3] or comparing to adjacent countries. If none of the proposals works, an average fraction of 25% sour gas[4] can be applied.

Town gas originates from outgassing of hard coal under air exclusion in retort furnace or chamber kilns. Emissions from these processes are considered in 1.B.1.b "solid fuel transformation." If town gas is processed in a gas processing plant, the emissions should be added, where emissions are computed as the product of the emission factor for town gas processing times the amount of town gas processed at the gas processing plant (in units of millions of cubic meters of town gas). For each category/subcategory listed in Table 4.2.11 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$E_{\text{processing}} = A_{\text{gas processed}} \times EF_{\text{LDAR or no LDAR}} + A_{\text{sour gas processed}} \times EF_{\text{acid gas removal}} + A_{\text{town gas processed at gas plant}} \times EF_{\text{town gas processing}}$$

TABLE 4.2.11
TIER 1 EMISSION FACTORS FOR GAS PROCESSING SEGMENT, 1.B.2.B.III.3

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

[3] http://www.sciencedirect.com/science/article/pii/S1876610211003018

[4] Mean value of Germany (40%) and USA (10%)

Processing	Without LDAR, limited use of dry seal compressors [a]	All	1.83	TBD	0.12	TBD	220.96-511.30	-75 to +250%	0.033-0.045	-10 to +1000%	Tonnes/million cubic meters gas processed
			1.65	TBD	0.11	TBD	NA	NA	NA	NA	Tonnes/million cubic meters gas produced
Processing	With LDAR, around 50% or more of centrifugal compressors are dry seal[b]	All	0.74	TBD	0.12	TBD	220.96-511.30	-75 to +250%	0.033-0.045	-10 to +1000%	Tonnes/million cubic meters gas processed
			0.56	TBD	0.09	TBD	NA	NA	NA	NA	Tonnes/million cubic meters gas produced
Sour gas (acid gas removal) Processing	All[c]	All	0.1	TBD	247	TBD	69.90-162.60	-75 to +250%	0.054-0.074	-10 to +1000%	Tonnes/million cubic meters sour gas processed

NA – Not Applicable, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted). NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

b. Emission factor s for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), and from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 2015 (most recent year of GHGRP data availability). NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

c. Emission factor s for CH_4 and CO_2 developed as an average of German and Austrian inventory data (1990 to 2016) with a range of 0.03 to 0.13 t CH_4/million cubic meters and 207 to 408 t CO_2/million cubic meter. NMVOC and N_2O factors are from 2006 IPCC Guidelines (range provided for developing and economies in transition, which includes the value for developed countries).

1 B 2 b iii 4. Transmission and Storage

This segment includes fugitive emissions (including leaks, venting and flaring) from systems used to transport processed natural gas to market (i.e., to industrial consumers and natural gas distribution systems), including natural gas storage systems. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities are used to move the gas throughout the transmission system. Emissions from natural gas liquids extraction plants on gas transmission systems should be reported as part of natural gas processing (Sector 1.B.2.b.iii.3). Fugitive emissions related to the transmission of natural gas liquids should be reported under 1.B.2.a.iii.3. Emissions sources include compressors, pneumatic controllers, storage wells, leaks and venting from transmission lines, equipment leaks from compressor stations. This source also includes LNG stations and import and export terminals. For the transmission segment, the extent of any leak detection and repair programs, and types of compressors in the country should be assessed. Where this information is unknown, or where there are limited or no leak detection or repair programs, and little use of centrifugal compressors, the first set of emission factors for gas transmission should be used. Where there are leak detection or repair programs, and use of centrifugal compressors with dry seals, the second set of emission factors for gas transmission should be used. Emission factors for gas transmission are presented in units of tonne per million cubic meter gas consumption, and in tonne per km transmission pipeline. For the storage segment, the extent of any leak detection and repair programs should be assessed. Where this information is unknown, or where there are limited or no leak detection or repair programs, the first set of emission factors for gas transmission should be used. Where there are leak detection or repair programs, the second set of emission factors for gas storage should be used. Emission factors are presented in units of tonne per million cubic meter gas consumption. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. In addition, where LNG imports and exports or storage occur, the number of stations should be determined, and the emission factors for LNG should be used. Information for disaggregating the Tier 1 EF for transmission is available in Annex 4A.2.

For each category/subcategory listed in Table 4.2.12 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$\boldsymbol{E}_{\textbf{transmission and storage}} = \boldsymbol{A}_{\textbf{gas transmission}} \times \boldsymbol{EF}_{\textbf{transmission}} + \boldsymbol{A}_{\textbf{storage}} \times \boldsymbol{EF}_{\textbf{storage}} + \boldsymbol{A}_{\textbf{LNG import/export}} \times \boldsymbol{EF}_{\textbf{LNG import/export}} + \boldsymbol{A}_{\textbf{LNG storage}} \times \boldsymbol{EF}_{\textbf{LNG storage}}$$

TABLE 4.2.12
TIER 1 EMISSION FACTORS FOR GAS TRANSMISSION AND STORAGE SEGMENT, 1.B.2.B.III.4

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

Gas Transmission	Most activities occurring with higher-emitting technologies and practices[a]	All	3.36	TBD	0.09	TBD	11.60-27.00	-100 to +250%	NA	NA	Tonnes per million cubic meter gas consumption
			4.10	TBD	0.11	TBD	NA	NA	NA	NA	Tonnes per km pipeline
Gas Transmission	Most activities occurring with lower-emitting technologies and practices[b]	All	1.30	TBD	0.04	TBD	11.60-27.00	-100 to +250%	NA	NA	Tonnes per million cubic meter gas consumption
			2.07	TBD	0.06	TBD	NA	NA	NA	NA	Tonnes per km pipeline
Gas Storage	Most activities occurring with higher-emitting technologies and practices[c]	All	0.67	TBD	0.18	TBD	0.36-0.83	-20 to +500%	NA	NA	Tonnes per million cubic meter gas consumption
Gas Storage	Extensive use of LDAR[d]	All	0.27	TBD	0.01	TBD	0.36-0.83	-20 to +500%	NA	NA	Tonnes per million cubic gas consumption
LNG	Import/Export [e]	All	2885	TBD	30,881	TBD	NA	NA	NA	NA	Tonnes per station
LNG	Storage [f]	All	1039	TBD	33	TBD	NA	NA	NA	NA	Tonnes per station

NA – Not Applicable, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. Emission factors for CH4 and CO2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted). NMVOC and N_2O factors are from 2006 IPCC Guidelines (range provided for developing and economies in transition, which includes the value for developed countries).

b. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), Zimmerle et al. 2015, and from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 2015 (most recent year of GHGRP data availability). NMVOC and N_2O values from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

c. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted). NMVOC and N_2O values from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

d. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), Zimmerle et al. 2015, and from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 2014 (most recent year of GHGRP data availability, without anomalous leak event). NMVOC and N_2O values from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

e. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory; average of 1990-2015 emissions.

f. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory; average of 1990-2015 emissions.

1 B 2 b iii 5. Distribution

This segment includes fugitive emissions (including leaks, venting, and flaring) from the distribution of natural gas to end users. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Emission sources include leaks from pipelines, metering and regulating stations, meters, short-term surface storage and post-meter leaks. In the table below, several options for emission factors are presented. The mix of pipeline materials and extent of any leak detection and repair programs in the country should be assessed. Where this information is unknown, or where distribution pipelines are less than 50% plastic, and where there are limited or no leak detection or repair programs, the first set of emission factors for gas distribution should be used. Where greater than 50% of distribution pipelines are plastic, and leak detection and repair programs are in use, use the second set of emission factors for gas distribution. As technologies and practices change over time, it is possible that one EF will be used in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series. Emission factors are presented both in units of tonne per million cubic meter gas consumption, and in tonnes per km pipeline. The inventory compiler should assess which activity data are available and which activity data basis best reflects emissions in that segment for that country. In addition, an appropriate factor for appliance emissions, and power plant emissions if applicable, should be applied. Distribution system methane emissions from biogas are to be calculated here, and can be calculated using the provided emission factors, provided that methane content of the distributed gas is not expected to significantly differ from distributed natural gas. Fugitive emissions of carbon dioxide from biogas distribution are considered to be biogenic and are not reported under 1.B.2. The composition of town gas differs from natural gas (see explanation in introduction to chapter 4.2) and therefore emissions are estimated for town gas using distinct emission factors. The emission factors for appliances and power plants include leakage emissions beyond gas meters, such as internal piping and the end of pipe appliances (e.g. home heating, water heating, saunas, stoves, barbecues). Emissions from combustion of gas are calculated in category 1.A. If the number of appliances using natural gas is unknown the number of gas meters or the number of house connections should be used instead multiplied by a typical number of appliances (e.g., 2 for countries with heaters and stoves; 1 in warm countries without heaters). Disaggregated emission factors (e.g. by pipeline material) are available in Annex 4A.2.

For each category/subcategory listed in Table 4.2.13 below that is occurring in the country, compilers must calculate emissions, and sum them according to the equation below. It is recognized that not all countries will have all categories and subcategories occurring.

$$E_{\text{distribution}} = A_{\text{gas distribution}} \times EF_{\text{gas distribution}} + A_{\textit{surface storage}} \times EF_{\textit{surface storage}} + A_{\textit{Distribution of town gas}} \times EF_{\textit{Distribution of town gas}} + A_{\textit{natural gas vehicles}} \times EF_{\textit{natural gas vehicles}} + A_{\textit{natural gas appliances}} \times EF_{\textit{natural gas appliances}} + A_{\textit{natural gas power plants}} \times EF_{\textit{natural gas power plants}}$$

TABLE 4.2.13
TIER 1 EMISSION FACTORS FOR DISTRIBUTION SEGMENT, 1.B.2.B.III.5

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

Gas Distribution	Less than 50% plastic pipelines, and limited or no leak detection and repair programs[a]	All	2.92	TBD	0.08	TBD	16.00 – 36.00	-20 to +500%	NA	NA	Tonnes per million cubic meter gas consumption
			1.17	TBD	0.03	TBD	NA	NA	NA	NA	Tonnes per kilometer of pipeline
Gas Distribution	Greater than 50% plastic pipelines, and leak detection and repair programs are in use[b]	All	0.57	TBD	0.02	TBD	16.00 – 36.00	-20 to +500%	NA	NA	Tonnes per million cubic meter gas consumption
			0.21	TBD	0.01	TBD	NA	NA	NA	NA	Tonnes per kilometer of pipeline
Gas Distribution	Short term surface storage[c]	All	5	TBD	0.034	TBD	NA	NA	NA	NA	Tonnes per million cubic meter of gas stored
		All	0.004	TBD	2.7 *10^-5	TBD	NA	NA	NA	NA	Tonnes per million cubic meter gas consumed
Distribution of town gas	All[d]	All	0.58	TBD	18.3 * 10^-3	TBD	NA	NA	NA	NA	Tonnes per kilometer of pipeline
Natural Gas Vehicles	Natural gas-fueled vehicles[e]	All	0.33 * 10^-3	TBD	2.2 * 10^-6	TBD	NA	NA	NA	NA	Tonnes per car
Appliances	Appliances in commercial and residential sector[f]	All	5 * 10^-3	TBD	9.6 * 10^-6	TBD	NA	NA	NA	NA	Tonnes per appliance

Industrial plants and power plants	Leakage at industrial plants and power stations[g]	All	0.4	TBD	3.2 * 10^-3	TBD	NA	NA	NA	NA	Tonnes per million cubic meter Non-residential and commercial gas consumed

NA – Not Applicable, TBD – To Be Determined (the default values are being developed and will be provided in the second order draft)

a. Emission factors for CH_4 and CO_2 developed from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 1992 (when EPA/GRI study was conducted). NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

b. Emission factors for CH_4 and CO_2 developed from data reported to the U.S. Greenhouse Gas Reporting Program (GHGRP), Lamb et al. 2015, and from EPA/GRI, Methane Emissions from the Natural Gas Industry (1996), as applied in the 2017 U.S. GHG Inventory to calculate emissions for the year 2015 (most recent year of GHGRP data availability). NMVOC and N_2O values are from IPCC 2006 GL, for developing and economies in transition; range includes the IPCC 2006 GL value for developed countries.

c. Short term storage. Bender & Langer, Mueller BBM "Determination of Emission Factors and Activity Data in the Area of the IPCC (1996) 1.B.2.b.iii - Fugitive Emissions from Natural Gas Storage"; Federal Environmental Agency of Germany, 2012 Funding code (FKZ): 360 16 035; Report no. M96023/01; 38 pages

d. Mean emission factors for CH_4 and CO_2 from German inventory data (1990-1997)

e. Gas vehicles. Bender & Langer, Mueller BBM "Determination of Emission Factors and Activity Data in the Area of the IPCC (1996) 1.B.2.b.iii - Fugitive Emissions from Natural Gas Storage"; Federal Environmental Agency of Germany, 2012 Funding code (FKZ): 360 16 035; Report no. M96023/01; 38 pages

f. Medium value of table 4.2.8 of 2006 GL (g) (appliances)

g. Value from 1996 GL table 1-5-8 (h) (power plants)

1 B 2 b iii 6 Other

Fugitive emissions (including leaks, venting and flaring) from natural gas systems not otherwise accounted for in the above categories. This may include emissions from well blowouts and pipeline ruptures or dig-ins, accidents, and emergency pressure releases. It is *good practice* to quantify and report such emissions as part of category 1.B.2.b.iii.6 whenever possible. There is no Tier 1 method available for such events, which need to be evaluated on a case-by-case basis, often using a combination of emission factors and engineering calculations. An example of calculating emissions during emergency conditions though an engineering calculation approach is given in the 2009 American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. Other examples of quantifying anomalous leak events include ARB's Aliso Canyon report (CARB 2016).

1 B2biii7 Abandoned Gas Wells

Available information on abandoned oil and gas wells do not indicate a clear distinction between abandoned oil and abandoned gas wells regarding practices or emission factors. As such, please refer to the discussion for 1.B.2.a.iii.7 for background and guidance on abandoned oil wells. The emission factors are presented in Table 4.2.8. In the future, as additional data on this source become available, distinct emission factors for oil and gas may be possible.

The factors in Tables 4.2.3 to 4.2.13 are derived using detailed emission inventory results from the United States, Canada, Australia, Germany, and other countries, and, where possible, have been updated from the values previously presented in the IPCC Guidelines for National Greenhouse Gas Inventories (2006) document to reflect the results of more current and refined emissions inventories. In many cases, technology- and practice-specific emission factors are presented, so that an inventory compiler may select factors that best represent industry practices in the country. While the emission factor options are meant to cover technologies and practices that are common in the oil and gas industries, technologies and practices can vary significantly; information on other emission factors developed from other data sets are presented in Annex 4A.2.

Further, the emission factors presented above represent aggregate emissions of leaks, venting, and flaring. Disaggregated versions of the factors are presented in Annex 4A.2.

A similar approach has also been used to estimate the uncertainty values given for the presented emission factors. The large uncertainties given for some of the emission factors reflect the corresponding high variability between individual sources, the types and extent of applied controls and, in some cases, the limited amount of data available. For many source categories (e.g., equipment leaks), the fugitive emissions have a skewed distribution where most of the emissions are emitted by only a small percentage of the population. Where uncertainties are less than or equal to ±100 percent, a normal distribution has been assumed, resulting in a symmetric distribution about the mean. Wherever the reported uncertainty, U percent, for a quantity Q is greater than 100 percent, the upper limit is Q(100+U)/100 and the lower limit is 100Q/(100+U).

TIER 3 AND 2

Emission factors for conducting Tier 3 and Tier 2 assessments are not provided in the IPCC Guidelines due to the large amount of such information and the fact these data are continually being updated to include additional measurement results and to reflect development and penetration of new control technologies and requirements. Rather, the IPCC has developed an Emission Factor Database (EFDB) which will be periodically updated and is available at www.ipcc-nggip.iges.or.jp/EFDB/main.php. In addition, regular reviews of the literature and country-specific data available through inventories of countries with similar circumstances should still be conducted to ensure that the best available factors are being used. The references for the chosen values should be clearly documented. Typically, emission factors are developed and published by environmental agencies, industry associations and academic literature. It may be necessary to develop inventory estimates in consultation with these organisations. For example, the American Petroleum Institute(API) maintains a Compendium of Emissions Estimating Methodologies for the Oil and Gas Industry, most recently updated in 2009. The API Compendium is available at:

http://www.api.org/~/media/Files/EHS/climate-change/2009_GHG_COMPENDIUM.pdf A software tool for estimating greenhouse gas emissions using equations from the API Compendium is available at:

http://ghg.api.org

Guidance for estimating greenhouse gas emissions has also been developed by a number of national oil and gas industry associations. Such documents may be useful supplemental references and often provide tiered source-specific calculation procedures. Guidance on inventory accounting principles as they apply to the oil and gas industry, and boundary definitions is available in the Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions (International Petroleum Industry Environmental Conservation Association, 2011):

http://www.api.org/~/media/Files/EHS/climate-change/GHG_industry-guidelines-IPIECA.pdf .

When selecting emission factors, the chosen values must be valid for the given application and be expressed on the same basis as the activity data. It also may be necessary to apply other types of factors to correct for site and regional differences in operating conditions and design and maintenance practices, for example:

- Composition profiles of gases from particular oil and gas fields to correct for the amount of CH_4, formation CO_2 and other target emissions;
- Annual operating hours to correct for the amount of time a source is in active service;
- Efficiencies of the specific control measures used.

The following are additional matters to consider in choosing emission factors:

- It is important to assess the applicability of the selected factors for the target application to ensure similar or comparable source behaviour and characteristics;
- In the absence of better data, it may sometimes be necessary to apply factors reported for other regions that practice similar levels of emission control and feature comparable types of equipment;
- Where measurements are performed to develop new emission factors, only recognised or defensible test procedures should be applied. The method and quality assurance (QA)/quality control (QC) procedures should be documented, the sampled sources should be representative of typical variations in the overall source population and a statistical analysis should be conducted to establish the 95 percent confidence interval on the average results.
- Whether and how the emission factors may change over time due to changes in technologies or practices.

4.2.2.4 CHOICE OF ACTIVITY DATA

UPDATED TO MOVE SENTENCE ON PRODUCTION STATISTICS TO THIS SECTION, AND UPDATED TABLES TO REFLECT REVISONS TO FACTORS AND NEW SUBCATEGORIES

The activity data required to estimate fugitive emissions from oil and gas activities includes production statistics, infrastructure data (e.g., inventories of facilities/installations, process units, pipelines, and equipment components), and reported emissions from spills, accidental releases, and third-party damages. The basic activity data required for each tier and each type of primary source are summarised in Table 4.2.6, Typical Activity Data Requirements for each Assessment Approach by Type of Primary Source Category. Production statistics provided by national bureaux should be used in favour of those available from international bodies, such as the IEA or the UN, due to their generally better reliability and disaggregation. Regional, provincial/state and industry reporting groups may offer even more disaggregation.

TIER 1

The activity data required at the Tier 1 level has been limited to information that may either be obtained directly from typical national oil and gas statistics or easily estimated from this information. Table 4.2.14 below lists the relevant activity data for each of the Tier 1 emission factors presented in Tables 4.2.3 to 4.2.13, and gives appropriate guidance for obtaining or estimating each of the required activity values.

TIER 2

The activity data required for the standard Tier 2 methodological approach is the same as that required for the Tier 1 approach. If the alternative Tier 2 approach described in Section 4.2.2.2 for crude oil systems is used, then additional, more detailed, information is required including average GOR values, information on the extent of gas conservation and factors for apportioning waste associated gas volumes between venting and flaring. This additional information should be developed based on input from the industry.

TABLE 4.2.14 (ELABORATION)
TYPICAL ACTIVITY DATA REQUIREMENTS FOR EACH ASSESSMENT APPROACH FOR FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS BY TYPE OF PRIMARY SOURCE CATEGORY

Assessment Tier	Primary Source Category	Minimum Required Activity Data
3	Process Venting/Flaring	Reported Volumes Gas Compositions Proration Factors for Splitting Venting from Flaring
	Storage Losses	Solution Gas Factors Liquid Throughputs Tank Sizes Vapour Compositions
	Equipment Leaks	Facility/Installation Counts by Type Processes Used at Each Facility Equipment Component Schedules by Type of Process Unit Gas/Vapour Compositions
	Gas-Operated Devices	Schedule of Gas-operated Devices by Type of Process Unit Gas Consumption Factors Type of Supply Medium Gas Composition
	Accidental Releases & Third-Party Damages	Incident Reports/Summaries
	Gas Migration to the Surface & Surface Casing Vent Blows	Average Emission Factors & Numbers of Wells
	Drilling	Number of Wells Drilled Reported Vented/Flared Volumes from Drill Stem Tests Typical Emissions from Mud Tanks
	Well Servicing	Tally of Servicing Events by Types
	Pipeline Leaks	Type of Piping Material Length of Pipeline
	Exposed Oils ands/Oil Shale	Exposed Surface Area Average Emission Factors
	Abandoned wells	Number of leaking abandoned wells Total annual methane volumes from abandoned wells

2	Venting and Flaring from Oil Production	Gas to Oil Ratios Flared and Vented Volumes Conserved Gas Volumes Re-injected Gas Volumes Utilised Gas Volumes Gas Compositions
	All Others	See table 4.2.15, which is relevant to Tier 2 as well as Tier 1.
	Abandoned wells	Number of abandoned oil and gas wells (plugged and unplugged) Emission rates per each type of abandoned well
1	All	See table 4.2.15 below.

TABLE 4.2.15 (ELABORATION)
GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS

Category	Sub-Category	Activity Data Values	Guidance
Gas Exploration	Unconventional	unconventional oil wells drilled	Reference directly from national statistics; if unavailable, use total unconventional oil wells and applicable EF.
		total unconventional oil wells	Reference directly from national statistics; if unavailable, use total unconventional oil production and applicable EF.
		10^3 m^3 total unconventional oil production	Reference directly from national statistics.
	Conventional	conventional oil wells drilled	Reference directly from national statistics; if unavailable, use total conventional oil wells and applicable EF.
		total conventional oil wells	Reference directly from national statistics; if unavailable, use total conventional oil production and applicable EF.
		10^3 m^3 total conventional oil production	Reference directly from national statistics.
Gas Production	All	total gas wells	Reference directly from national statistics; if unavailable, use gas production, and the applicable EF.
		10^6 m^3 gas production	Reference directly from national statistics.

Gas Processing	Sweet Gas Plants	10^6 m^3 raw gas feed	Reference directly from national statistics if total gas receipts by gas plants is reported, otherwise, assume this value is equal to total gas production. Apportion this value accordingly between sweet and sour plants. In the absence of any information to allow such apportioning assume all plants are sweet.
	Sour Gas Plants	10^6 m^3 raw gas feed	
	Default Weighted Total	10^6 m^3 gas production	Reference directly from national statistics.
Gas Transmission & Storage	Transmissi on	km of transmission pipeline	Reference directly from national statistics if available; if unavailable, use marketable gas and the applicable EF.
	Transmissi on	10^6 m^3 of marketable gas	Reference directly from national statistics using the value reported for total net supply. This is the sum of imports plus total net gas receipts from gas fields and processing or reprocessing plants after all upstream uses, losses and re-injection volumes have been deducted.
	Storage	10^6 m^3 of marketable gas	
Gas Distribution	All	km of distribution pipeline	Reference directly from national statistics if available; if unavailable, use utility sales and the applicable EF.
		10^6 m^3 of utility sales	Reference directly from national statistics if reported if available; otherwise, set equal to the amount of gas handled by gas transmission and storage systems minus exports.
Natural Gas Liquids Transport	Condensate	10^3 m^3 Condensate and Pentanes Plus	Reference directly from national statistics.
	Liquefied Petroleum Gas	10^3 m^3 LPG	Reference directly from national statistics.

TABLE 4.2.15 (ELABORATION) (CONTINUED)
GUIDANCE ON OBTAINING THE ACTIVITY DATA VALUES REQUIRED FOR USE IN THE TIER 1 APPROACH TO ESTIMATE FUGITIVE EMISSIONS FROM OIL AND GAS OPERATIONS

Oil Exploration	Unconventional	unconventional gas wells drilled	Reference directly from national statistics; if unavailable, use total unconventional gas wells and applicable EF.
		total unconventional gas wells	Reference directly from national statistics; if unavailable, use total unconventional gas production and applicable EF.
		10^3 m^3 total unconventional gas production	Reference directly from national statistics.
	Conventional	conventional gas wells drilled	Reference directly from national statistics; if unavailable, use total conventional gas wells and applicable EF.
		total conventional gas wells	Reference directly from national statistics; if unavailable, use total conventional gas production and applicable EF.
		10^3 m^3 total conventional gas production	Reference directly from national statistics.
Oil Production	Conventional Oil	10^3 m^3 conventional oil production	Reference directly from national statistics.
	Unconventional Oil	10^3 m^3 unconventional oil production	Reference directly from national statistics.
	Total Oil Production	10^3 m^3 total oil production	Reference directly from national statistics.
Oil Upgrading	All	10^3 m^3 oil upgraded	Reference directly from national statistics if available; otherwise, set equal to total heavy oil and bitumen production minus any exports of these crude oils.
Oil Transport	Pipelines	10^3 m^3 oil transported by pipeline	Reference directly from national statistics if available; otherwise set equal to total crude oil production plus imports.
	Tanker Trucks and Rail Cars	10^3 m^3 oil transported by Tanker Truck	Reference directly from national statistics if available; otherwise, assume (as a first approximation) that 50 percent of the total crude.

	Loading of Off-shore Production on Tanker Ships	10^3 m^3 oil transported by Tanker Ship	Reference directly from national statistics using the value reported for crude oil exports, and apportion this amount to account for only the fraction exported by tanker ships. While exports may occur by pipeline, tanker ship, or tanker trucks, they will usually be almost exclusively by one of these methods. Tanker ships are assumed to be used almost exclusively for exports.
Oil Refining	All	10^3 m^3 oil refined.	Reference directly from national statistics if available; otherwise set this value equal to total production plus imports minus exports.
Refined Product Distribution	Gasoline	10^3 m^3 product distributed.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.
	Diesel	10^3 m^3 product transported.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.
	Aviation Fuel	10^3 m^3 product transported.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.
	Jet Kerosene	10^3 m^3 product transported.	Reference directly from national statistics if available; otherwise, set it equal to total gasoline production by refineries plus imports minus exports.

Abandoned wells	All	Well number (The activity data minimum required for Tier 1 is total number of abandoned wells in each year of the time series. If consider more disaggregated Tier 1, total number of abandoned wells should be split depending on plugging status and location (on- or offshore)	It may be directly referenced from national statistic if available. Otherwise, several approaches (or their combination) on count of abandoned wells number in each year of the time series may be suggested. (1) Counting the total number of wells existing but no longer reporting production as of a given year; (2) Counting wells drilled as of a given year, then subtracting the number of actively producing wells in that year; (3) Counting wells that were waiting for decommissioning (and producing in case of accounting it_ see comment below) at the year before the given year. It should be noted that the number of abandoned wells at each year must be added to number of abandoned wells at all previous years starting from the year when first well abandonment (or drilling activities) took place. In this point, the count of abandoned wells number at base year should be the most challenging.

TIER 3

Specific matters to consider in compiling the detailed activity data required for use in a Tier 3 approach include the following:

- Production statistics should be disaggregated to capture changes in throughputs (e.g., due to imports, exports, reprocessing, withdrawals, etc.) in progressing through oil and gas systems.
- Production statistics provided by national bureaux should be used in favour of those available from international bodies, such as the IEA or the UN, due to their generally better reliability and disaggregation. Regional, provincial/state and industry reporting groups may offer even more disaggregation.
- Production data used in estimating fugitive emissions should be corrected, where applicable, to account for any net imports or exports. It is possible that import and export data may be available for a country while production data are not; however, it is unlikely that the opposite would be true
- Where coalbed methane is produced into a natural gas gathering system, any associated fugitive emissions should be reported under the appropriate natural gas exploration and production categories. This will occur by default since the produced gas becomes a commodity once it enters the gas gathering system and automatically gets accounted for the same way gas from any other well does when it enters the gathering system. The fact that gas is coming from a coal formation would only be discernable at a very disaggregated level. Where a coal formation is degassed for the purposes of coal exploration or coal mining and handling, the associated emissions should be allocated to the coal sector under the appropriate section of IPCC category 1.B.1.
- Vented and flared volumes from oil and gas statistics may be highly suspect since these values are usually estimates and not based on actual measurements. Additionally, the values are often aggregated and simply reported as flared volumes. Operating practices of each segment of the industry should be reviewed with industry representatives to determine if the reported volumes are actually vented or flared, or to develop appropriate apportioning of venting relative to flaring. Audits or reviews of each industry segment should also be conducted to determine if all vented and flared volumes are actually reported (for example, solution gas emissions from storage tanks and treaters, emergency flaring/venting, leakage into vent/flare systems, and blowdown and purging volumes may not necessarily be accounted for).
- Infrastructure data are more difficult to obtain than production statistics. Information concerning the numbers and types of major facilities and the types of processes used at these facilities may often be available from regulatory agencies and industry groups, or directly from the actual companies.

- Information on minor facilities (e.g., numbers of field dehydrators and field compressors) usually is not available, even from oil and gas companies. Consequently, assumptions must be made, based on local design practices, to estimate the numbers of these facilities. This may require some fieldwork to develop appropriate estimation factors or correlations.
- Many companies use computerised inspection-and-maintenance information management systems. These systems can be a very reliable means of counting major equipment units (e.g., compressor units, process heaters and boilers, etc.) at selected facilities. Also, some departments within a company may maintain databases of certain types of equipment or facilities for various internal reasons (e.g., tax accounting, production accounting, insurance records, quality control programmes, safety auditing, license renewals, etc.). Efforts should be made to identify these potentially useful sources of information.
- Component counts by type of process unit may vary dramatically between facilities and countries due to differences in design and operating practices. Thus, while initially it may be appropriate to use values reported in the general literature, countries should strive to develop their own values.
- Use of consistent terminology and clear definitions is critical in developing counts of facilities and equipment components, and to allow any meaningful comparisons of the results with others.
- Some production statistics may be reported in units of energy (based on their heating value) and will need to be converted to a volume basis, or vice versa, for application of the available emission factors. Typically, where production values are expressed in units of energy, it is in terms of the gross (or higher) heating value of the product. However, where emission factors are expressed on an energy basis it is normally in terms of the net (or lower) heating value of the product. To convert from energy data on a GCV basis to a NCV basis, the International Energy Agency assumes a difference of 5 percent for oil and 10 percent for natural gas. Individual natural gas streams that are either very rich or high in impurities may differ from these average values. Emission factors and activity data must be consistent with each other.
- Oil and gas imports and exports will change the activity levels in corresponding downstream portions of these systems.
- Production activities will tend to be the major contributor to fugitive emissions from oil and gas activities in countries with low import volumes relative to consumption and export volumes. Gas transmission and distribution and petroleum refining will tend to be the major contributors to these emissions in countries with high relative import volumes. Overall, net importers will tend to have lower specific emissions than net exporters.

4.2.2.5 COMPLETENESS

UPDATED TO REMOVE REFERENCE TO PREVIOUS COMPLETENESS TABLE, WHICH WAS INCONSISTENT WITH BOTH 2006GL AND THE 2019 REFINEMENTS

Completeness is a significant issue in developing an inventory of fugitive emissions for the oil and gas industry. It can be addressed through direct comparisons with other countries and, for refined inventories, through comparisons between individual companies in the same industry segment and subcategory. This requires the use of consistent definitions and classification schemes. For example, in Canada, the upstream petroleum industry has adopted a benchmarking scheme that compares the emission inventory results of individual companies in terms of production-energy intensity and production-carbon intensity. Such benchmarking allows companies to assess their relative environmental performance. It also flags, at a high level, anomalies or possible errors that should be investigated and resolved.

The Tier 1 EF and their associated uncertainty ranges presented in Tables 4.2.3 to 4.2.13 may be used to assess reasonableness of Tier 2 and Tier 3 factors. If emissions from specific segments are appreciably less than the low end or greater than the high end of the uncertainty range, this should be explained; otherwise, it may be an indication of possible missed or double counted contributions, respectively. The ranking of specific methane losses relative to the presented indicative factors should not be used as a basis for choosing the most appropriate assessment approach; rather, total emissions (i.e. the product of activity data and emission factors), the complexity of the industry and available assessment resources should all be considered.

Where emission inventories are developed based on a compilation of individual company-level inventories, care should be taken to ensure that all companies are included. Appropriate extrapolations may be needed to account for any non-reporting companies.

Smaller individual sources, when aggregated nationally over the course of a year, may often be significant total contributors. Therefore, good practice is not to disregard them. Once a thorough assessment has been done, a basis exists for simplifying the approach and better allocating resources in the future to best reduce uncertainties in the results.

Where a country has estimated its fugitive emissions from part or all of its oil and natural gas system based on a roll-up of estimates reported by individual oil and gas companies, it is good practice to document the steps taken to ensure that these results are complete, transparent and consistent across the time series. Corrections made to account for companies or facilities that did not report, and measures taken to avoid missed or double counting (particularly where ownership changes have occurred) and to assess uncertainties should be highlighted.

Where Tier 2 or Tier 3 approaches are used to calculate a subset of emissions (e.g. flaring), care should be taken to ensure that all remaining emissions (e.g. venting and fugitives) are accounted (e.g. using disaggregated Tier 1 factors in Appendix 4A.2).

4.2.2.6 DEVELOPING CONSISTENT TIME SERIES

UPDATED TO REFLECT CHANGING PRACTICES AND TECHNOLOGIES OVER TIME

Ideally, emission estimates will be prepared for the base year and subsequent years using the same method. The aim is to have emission estimates across the time series reflect true trends in greenhouse gas emissions. Emission or control factors that change over time (e.g., due to changes in source demographics or the penetration of control technologies) should be regularly updated and, each time, only applied to the period for which they are valid. For, example, if an emission control device is retrofit to a source then a new emission factor will apply to that source from then onwards; however, the previously applied emission factor reflecting conditions before the retrofit should still be applied for all previous years in the time series. If an emission factor has been refined through further testing and now reflects a better understanding of the source or source category, then all previous estimates shouldbe updated to reflect the use of the improved factor and be reported in a transparent manner.

Tier 1 emission factors provided in table 4.2.3 to 4.2.13 are technology-specific to the extent possible. A country should assess which technologies and practices are generally in place in the country and apply the corresponding emission factor. As technologies and practices change over time, it is possible that a country will use one EF in some years and another in other years. A compiler should assess the time frame over which changes took place, and consider linear interpolation or other techniques to incorporate the trend from one emission factor to another over the time series.

Where some historical data are missing, it should still be possible to use source-specific measurement results combined with back-casting techniques to establish an acceptable relationship between emissions and activity data in the base year. Approaches for doing this will depend on the specific situation, and are discussed in general terms in Volume 1 Chapter 5 of the 2006 Guidelines.

If emission estimates are developed based on a roll-up of individual company estimates, greater effort will be required to maintain time series consistency, particularly where frequent facility ownership changes occur and different methodologies and emission factors are applied by each new owner without also carrying these changes back through the time series.

4.2.2.7 UNCERTAINTY ASSESSMENT

UPDATED TO REFLECT CHANGING PRACTICES AND TECHNOLOGIES OVER TIME

Sources of error that may occur include the following:

- Measurement errors;
- Extrapolation errors;
- Inherent uncertainties of the selected estimation techniques;
- Missing or incomplete information regarding the source population and activity data;
- Poor understanding of temporal and seasonal variations in the sources;
- Over or under accounting due to confusion or inconsistencies in category divisions and source definitions;
- Misapplication of activity data or emission factors (including due to incomplete information for assigning technology- and practice-specific emission factors);
- Errors in reported activity data;

- Missed accounting of intermediate transfer operations and reprocessing activities (for example, re-treating of slop oil, treating of foreign oil receipts and repeated dehydration of gas streams: in the field, at the plant, and then following storage);
- Differences in the effectiveness of control devices, potential deterioration of their performance over time and missed accounting of control measures.

Guidance regarding the assessment of uncertainties in emission factors and activity data are presented in the subsections below.

4.2.2.7.1 EMISSION FACTOR UNCERTAINTIES

The uncertainty in an emission factor will depend both on the accuracy of the measurements upon which it is based and the degree to which these results reflect the average behaviour of the target source population. Accordingly, emission factors developed based on data measured in one country may have one set of uncertainties when the factors are applied in that country and another set of uncertainties when they are applied similarly in a different country. Thus, while it is difficult to establish one set of uncertainties that will always apply, a set of default values has been provided for the default factors provided in Tables 4.2.3 through 4.2.13. These uncertainties are estimated based on expert judgement and reflect the level of uncertainty that may be expected when the corresponding emission factors are used to develop emission estimates at the national level. Use of the presented factors to estimate emissions from individual facilities or sources would be expected to result in much greater uncertainties.

4.2.2.7.2 ACTIVITY DATA UNCERTAINTIES

The percentages cited in this section are based on expert judgement and aim to approximate the 95 percent confidence interval around the central estimate. Gas compositions are usually accurate to within ±5 percent on individual components. Flow rates typically have errors of ±3 percent or less for sales volumes and ±15 percent or more for other volumes. Production statistics or disposition analyses may not agree between different reporting agencies even though they are based on the same original measurement results (e.g. due to possible differences in terminology and potential errors in summarising these data). These discrepancies may be used as an indication of the uncertainty in the data. Additional uncertainty will exist if there is any inherent bias in the original measurement results (for example, sales meters are often designed to err in favour of the customer, and liquid handling systems will have a negative bias due to evaporation losses). Random metering and accounting errors may be assumed to be negligible when aggregated over the industry.

Where available, counts of major facilities (e.g., gas plants, refineries and transmission compressor stations) may be known with little error (e.g., less than 5 percent). Where errors in these counts occur it is usually due to some uncertainties regarding the number of new facilities built and old facilities decommissioned during the time period.

Counts of well site facilities, minor field installations and gas gathering compressor stations, as well as the type and amount of equipment at each site, will be much less accurately known, if known at all (e.g., at least ±25 percent uncertainty or more).

Estimates of emission reductions from individual control actions may be accurate to within a few percent to ±25 percent depending on the number of subsystems or sources considered.

4.2.3 Inventory Quality Assurance/Quality Control (QA/QC)

It is good practice to conduct quality control checks as outlined in Volume 1 Chapter 6 of the 2006 IPCC Guidelines, Tier 1 General Inventory Level QC Procedures, and expert review of the emission estimates. Additional quality control checks, as outlined in Volume 1 Chapter 5 of the 2006 IPCC Guidelines, and quality assurance procedures may also be applicable, particularly if higher tier methods are used to determine emissions from this source category. Inventory compilers are encouraged to use higher tier QA/QC for key categories as identified in Volume 1 Chapter 4 of the 2006 IPCC Guidelines.

In addition to the guidance in Volume 1 Chapter 6 of the 2006 IPCC Guidelines, specific procedures of relevance to this source category are outlined below.

INDUSTRY INVOLVEMENT

Emission inventories for large, complex oil and gas industries will be susceptible to significant errors due to missed or unaccounted for sources. To minimise such errors, it is important to obtain active involvement of industry and other technical experts in the preparation and refinement of these inventories. This will be especially important in the selection of appropriate technology- and practice-specific emission factors.

REVIEW OF DIRECT EMISSION MEASUREMENTS

UPDATED TO REFLECT THE LATEST INFORMATION

If direct measurements are used to develop country-specific emission factors, the inventory compiler should establish whether measurements at the sites were made according to recognised standard methods. If the measurement practices fail this criterion, then the use of these emissions data should be carefully evaluated, estimates reconsidered and qualifications documented. The compiler should also assess key background information in the study, such as, what activities are occurring and what equipment in place (including controls) at the time of measurement and whether the measurements are representative of average conditions for that activity and may be applied as an average factor, or if it should be adjusted for different operating practices, etc. The compiler should confirm that the categorizations (e.g. for equipment and practices) used in the study are the same as used in the inventory, and should make adjustments if not. The national representativeness of the factors should also be assessed. As applicable, the attribution of measured emissions to the specific equipment or broader category should also be assessed.

ACTIVITY DATA CHECK

Several different types of activity data may be required for this source category, depending on which methodological tier is used to estimate the emissions. Where activity data are available from multiple sources (i.e. from national statistics and industry organisations) these data sets should be checked against each other to assess reasonableness. Significant differences in data should be explained and documented. Trends in the main emission drivers and activity data over time should be checked and any anomalies investigated.

EXTERNAL REVIEW

Emission inventories for large, complex oil and gas industries may be susceptible to errors due to missed or unaccounted for sources, or due to customization of average emission factors taken from a data source that represents estimates from another country or region with operating characteristics different from those in the country where the emission factor is being applied. To minimise such errors, it is important to obtain active involvement of industry and other technical experts in the preparation and refinement of these inventories.

4.2.4 Reporting and Documentation

UPDATED TO REFLECT CHANGING PRACTICES AND TECHNOLOGIES OVER TIME, AND UPDATED DISAGGREGATION BY SEGMENT

It is good practice to document and archive all information required to produce the national emissions inventory estimates, as outlined in Volume 1 Chapter 8 of the 2006 Guidelines.

It may not be practical to include all supporting documentation in the inventory report. However, at a minimum, the inventory report should include summaries of the methods used and references to source data such that the reported emissions estimates are transparent and the steps in their calculation may be retraced. For segments where a technology- or practice-specific Tier 1 emission factor is used, the rationale for selecting that factor and the method for applying the factors over the time series must be clearly documented. It is expected that many countries will use a combination of methodological tiers to evaluate the amount of fugitive greenhouse gas emissions from the different parts of their oil and natural gas systems. The specific choices should reflect the relative importance of the different subcategories and the availability of the data and resources needed to support the corresponding calculations. Table 4.2.16 is a sample template, with some example data entries, that may be used to conveniently summarize the applied methodologies and sources of emission factors and activity data. Tier 1 EF are inclusive of venting, flaring, and leak emissions. For calculations, compilers may separate their emissions into the separate categories of venting, flaring and leaks if data are available. Emissions reported for each segment should be inclusive of venting, flaring, and leak emissions (i.e., should represent the total emissions for that segment). If a compiler choses to report disaggregated data on venting and flaring, they may do so as information items under 1.B.2.a.i., 1.B.2.a.ii., 1.B.2.b.i., and 1.B.2.b.ii.

Since emission factors and estimation procedures are continually being improved and refined, it is possible for changes in reported emissions to occur without any real changes in actual emissions. Accordingly, the basis for any changes in results between inventory recalculations should be clearly discussed and those due strictly to changes in methods and factors should be highlighted.

The issue of confidential business information will vary from region to region depending on the number of firms in the market and the nature of the business. The significance of this issue tends to increase in progressing downstream through the oil and gas industry. A common means to address such issues where they do arise is to aggregate the data using a reputable independent third party.

The above reporting and documentation guidance is applicable to all methodological choices. Where Tier 3 approaches are employed, it is important to ensure that either the applied procedures are detailed in the inventory report or that available references for these procedures are cited since the IPCC Guidelines do not describe a standard Tier 3 approach for the oil and gas sector. There is a wide range in what potentially may be classified as a Tier 3 approach, and correspondingly, in the amount of uncertainty in the results. If available, summary performance and activity indicators should be reported to help put the results in perspective (e.g. total production levels and transportation distances, net imports and exports, and specific energy, carbon and emission intensities). Reported emission results should also include a trend analysis to show changes in emissions, activity data and emission intensities (i.e., average emissions per unit of activity indicator) over time. The expected accuracy of the results should be stated and the areas of greatest uncertainty clearly noted.

The current trend by some government agencies and industry associations is to develop detailed methodology manuals and reporting formats for specific segments and subcategories of the industry. This is perhaps the most practical means of maintaining, documenting and disseminating the subject information. However, all such initiatives must conform to the common framework established in the IPCC Guidelines so that the emission results can be compared across countries.

TABLE 4.2.16 (ELABORATION)
FORMAT FOR SUMMARIZING THE APPLIED METHODOLOGY AND BASIS FOR ESTIMATED EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS SHOWING SAMPLE ENTRIES

IPCC Code	Sector Name	Subcategory	Source Category	Method	Activity Data			Emission Factors			
					Type	Basis	Year	Basis/Reference[5]			Date Country Specific Values Updated
								CH_4	CO_2	N_2O	

[5] Include here information on basis for selecting technology/practice-specific factors, as applicable.

1.B.2	Oil and Natural Gas										
1.B.2.a	Oil										
1.B.2.a.i	Venting										
1.B.2.a.ii	Flaring										
1.B.2.a.iii	All Other										
1.B.2.a.iii.1	Exploration										
1.B.2.a.iii.2	Production and Upgrading										
1.B.2.a.iii.3	Transport										
1.B.2.a.iii.4	Refining										
1.B.2.a.iii.5	Distribution of oil products										
1.B.2.a.iii.6	Other										
1.B.2.a.iii.7	Abandoned Wells										
1.B.2.b	Natural Gas										
1.B.2.b.i	Venting										

TABLE 4.2.16 (ELABORATION) (CONTINUED)
FORMAT FOR SUMMARIZING THE APPLIED METHODOLOGY AND BASIS FOR ESTIMATED EMISSIONS FROM OIL AND NATURAL GAS SYSTEMS SHOWING SAMPLE ENTRIES

IPCC Code	Sector Name	Subcategory	Source Category	Method	Activity Data			Emission Factors			
								Basis/Reference			Date
					Type	Basis	Year	CH_4	CO_2	N_2O	Country Specific Values Updated
1.B.2.b.ii	Flaring										
1.B.2.b.iii	All Other										
1.B.2.b.iii.1	Exploration										
1.B.2.b.iii.2	Production	Well Servicing	All	Tier 1	Number of Active Wells	National Statistics	2005	D	D	D	---
		Gas Production	Equipment Leaks	Tier 1	Throughput	National Statistics	2005	EFDB	EFDB	EFDB	---

1.B.2.b.iii.3	Processing	All	Equipment Leaks	Tier 1	Throughpu t	National Statistics	2005	D	EFDB	EFDB	---
1.B.2.b.iii.4	Transmission and Storage	Gas Transmission	Equipment Leaks	Tier 2	Number of facilities	Industry Survey	2005	CS	CS	----	2005
1.B.2.b.iii.5	Distribution										
1.B.2.b.iii.6	Other										
1.B.2b.iii.7	Abandoned Wells										
1.B.3	Other emissions from Energy Production										

AP – API Compendium
D – IPCC Default Emission Factors
CS – Country-Specific Emission Factors
EFDB – IPCC Emission Factor Database

4.3 FUSITIVE EMISSIONS FROM FUEL TRANSFORAMATION

Intentional or unintentional release of greenhouse gases may occur during the extraction, processing and delivery of fossil fuels to the point of final use. These are known as fugitive emissions.

4.3.1 Overview and description of sources

This section is a new guidance. It clarifies how fugitive emissions from fuel transformation should be estimated. Emissions from these fuel transformation activities link to the Energy, IPPU and AFOLU sectors and cross references are provided to the relevant sections in the guidelines. Inventory compilers should ensure all emissions from specific fuel transformation activities are captured in the inventory.

Fugitive emissions from the following fuel transformation activities have been included in this section - charcoal production, coke production, other solid fuels to solid fuels, coal to liquid, gas to liquid, biomass to liquid, biomass to gas, and refineries. The boundaries for all these transformation activities are the respective transformation process boundaries, and fugitive emissions in upstream and downstream supply chains are to be estimated using appropriate methodologies elsewhere in these guidelines, including in other volumes.

TABLE 4.3.1
ESTIMATION AND REPORTING OF FUGITIVE EMISSIONS FROM FUEL TRANSFORMATION

Fuel transformation	**Methods for estimating fugitive emissions from the transformation of this fuel are set out in the following section of the Guidelines**	**Fugitive emissions from the transformation of this fuel should be reported under the following category**	**Methods for estimating emissions from the use of this fuel for energy purposes are set out in the following section of the Guidelines**	**Emissions from the use of this fuel for energy purposes should be reported under the following categories**
Charcoal production	4.3.2.1	1B1c	[add reference]	1A (and subcategories)
Coke production	4.3.2.2	1B1c	[add reference]	1A (and subcategories)
Solid to solid fuel production (wood pellets)	4.3.2.3	1B1c	[add reference]	CH4, N2O in 1A (and subcategories) CO2 as a memo item “CO2 emissions from biomass”
Gasification transformation	4.3.2.4	1B1c	[add reference]	1A (and subcategories)

Notes:
1B1c Solid Fuel Transformation

4.3.2 Methodological issues

4.3.2.1 CHARCOAL PRODUCTION

About half the wood extracted worldwide from forests is used to produce energy, mostly for cooking and heating. Some of the wood is used to make charcoal. The share of energy use from harvested wood is as high as 90 percent in Africa and more than 60 percent in Asia. An estimated 17 per cent of wood extracted from forests was converted to charcoal (FAO, 2016a), and most of the remainder was used in the form of fuelwood, producing 2 – 7 percent of global anthropogenic emissions. Charcoal production can be on very small scales (domestic) to larger scales (industrial), is normally poorly regulated with little or no emission control. Lifecycle emissions are due largely to unsustainable forest management, inefficient charcoal manufacture and woodfuel combustion (FAO, 2017; AFREA, 2011).

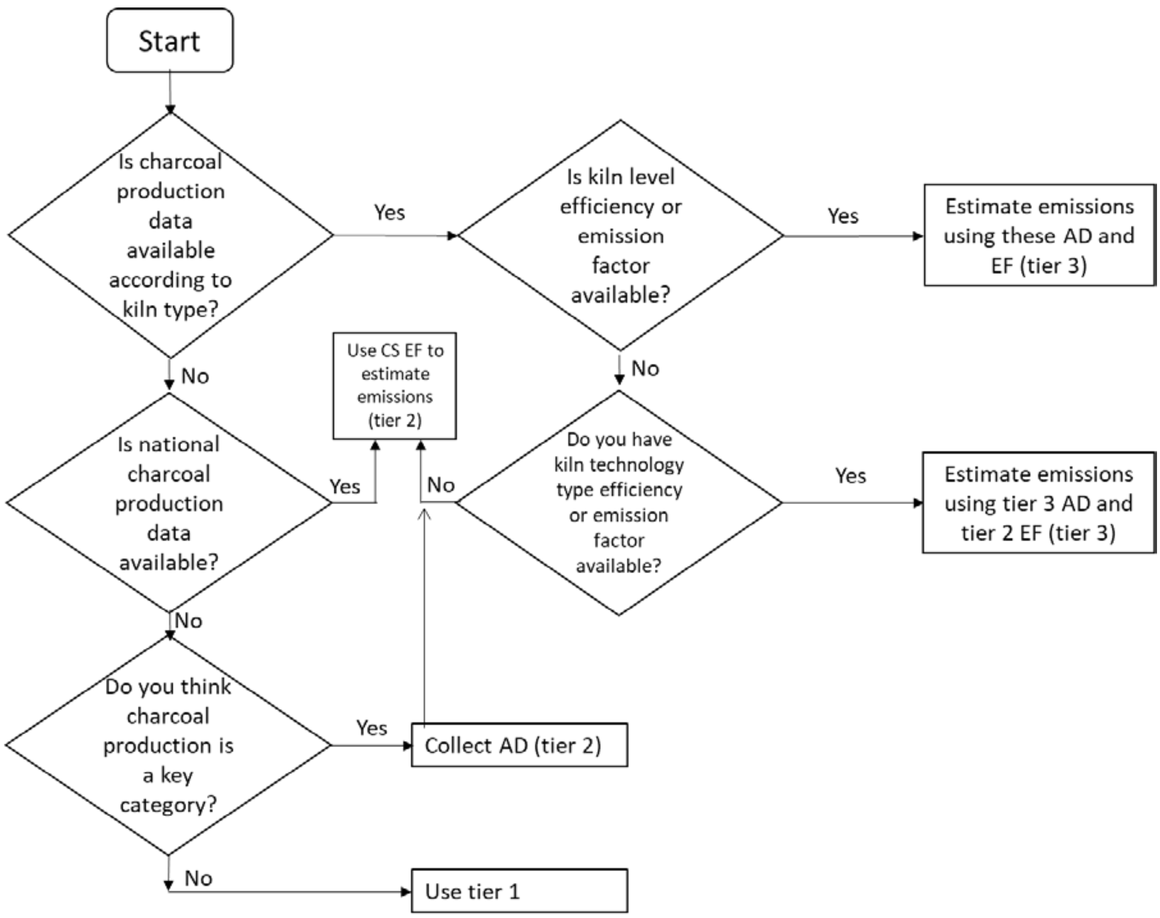
Charcoal produced using sustainably managed resources and improved technologies, however, is a low net emitter of greenhouse gases, thereby helping mitigate climate change while also increasing access to energy and food and providing income-generating opportunities (Iiyama *et al*., 2014b; Schure, Levang and Wiersum, 2014).

Charcoal is produced by the carbonization of wood. Carbonization of fuel is the thermal decomposition in the absence of oxygen at a temperature above 300°C. The carbonization of wood produces charcoal, volatile compounds and a range of gases. The gases produced include direct greenhouse gases (CO_2, CH_4 and N_2O), indirect greenhouse gases (CO) and other gases, including H_2. Emissions of CO_2 from charcoal production are considered under Land Use, Land-Use Change and Forestry (LULUCF). Fugitive emissions of CH_4 and N_2O are highly likely to occur.

CHOICE OF METHODS, DECISION TREES, TIERS

Figure 4.3.1 shows the decision tree for estimating fugitive emissions from charcoal production activities. For countries with kiln-level charcoal production data, or kiln type data, and who have kiln efficiency or emission factor data available, a Tier 3 estimation could be applied. For countries where country level charcoal production data is available, a country specific EF may be estimated and applied in a Tier 2 approach. However, if none of the detailed data set out above are available, but where charcoal production has been identified as a key category either qualitatively, or quantitatively, national level charcoal production data should be estimated along with a country specific EF (Tier 2). Otherwise a default EF can be used to estimate Tier 1 emissions.

Figure 4.3.1 Decision tree for charcoal production



Tier 1

The general form of the equation for estimating emissions for Tier 1 approach, based on charcoal production activity data is given by Equation 4.3.1 below.

EQUATION 4.3.1
FUGITIVE GHG EMISSIONS FROM CHARCOAL PRODUCTION

$$\text{Emissions}_{\text{GHG, charcoal produced}} = \text{Charcoal produced} \bullet \text{Emission Factor}_{\text{GHG}}$$

Where:

Emissions GHG, charcoal produced = emissions of a given GHG by type of fuel (kg GHG)

Charcoal produced = amount of charcoal produced [units]

Emission Factor GHG = emission factor according to charcoal kiln type, and GHG

Tier 1 emission factors are given in Table 4.3.2.

Tier 2 & 3

The Tier 2 and 3 methods uses Equation 4.3.1, but with higher tier or country specific EF. It is *good practice* for inventory compilers to apply an emission factor in Table 4.3.2 suitable to the technologies in use.

CHOICE OF EMISSION FACTOR

Table 4.3.2 provides a range of emission factors according to kiln technology type. Inventory compilers should select the factor appropriate for the gas, and technologies in use in their country.

TABLE 4.3.2
EMISSION FACTORS FOR CHARCOAL PRODUCTION ACCORDING TO KILN TECHNOLOGY

Gas	Emission Factor	Source
CH_4	22-89 kg CH_4/t charcoal	Bailis (2009) Taccini (2010)
	32 +- 5g CH_4 / kg charcoal produced	Chidumayo and Gumbo (2013)
	27 – 45 g CH_4 /kg charcoal produced	Muller Michaelowa & Eschman (2011)
	47 g CH_4/kg charcoal produced high efficiency kiln	Pennise et al (2001)
	40.7 g CH_4/kg charcoal produced low efficiency kiln	Smith et al (1999)
	0 – 0.036 kg CH_4/t charcoal produced high efficiency kiln	UNDP (2013)
N_2O	0.21 g N_2O / kg charcoal produced low efficiency kiln	Pennise et al (2001)
	0.076 g N_2O / kg charcoal produced high efficiency kiln	Pennise et al (2001)
	0.017 – 0.084 kg N_2O /t charcoal produced	Smith et al (1999)

CHOICE OF ACTIVITY DATA

Preference must be given to sourcing accurate charcoal production data. Charcoal production might be available in national energy balances. The quantities of charcoal produced might be recorded by statistical agencies, and could be estimated from the weight or volume of wood used to make charcoal. But, production may not be solely for domestic purposes, and some charcoal produced might be exported. Total charcoal production can be estimated by measuring the charcoal produced in each kiln countrywide each year. Measurement is done by weighing the bags of charcoal produced at each site. If gravimetric production activity is not available, quantities of charcoal produced can be approximately estimated from the product of the number of charcoal bags filled assuming each bag weighs 40 kg (reference?). Estimates of production made in this way should not be used for an inventory, but could be used to help verify production data from other sources.

UNCERTAINTY ASSESSMENT

The uncertainty associated with charcoal production is high as the use of this fuel is typically not accurately recorded at national level, and, most of the traditional charcoal makers do not measure the quantities of charcoal produced. Uncertainties associated with the charcoal production data might be available from statistical data. If such data are not available, then expert elicitation and expert judgement can be used. The uncertainties associated with the emission factors are very high. The emission factors depend on the type of kiln and corresponding efficiency. Since most of the charcoal is produced by traditional mound methods, which are not standardized, the emission factors will necessarily be highly uncertain.

TABLE 4.3.3
DEFAULT UNCERTAINTY ASSESSMENT FOR EMISSION FACTORS FROM CHARCOAL PRODUCTION

Kiln technology	CH_4	N_2O
Low efficiency kiln	Order of magnitude [a]	Order of magnitude [a]
High efficiency kiln	Order of magnitude [a]	Order of magnitude [a]
Mound kiln	Order of magnitude [a]	Order of magnitude [a]

Note:

[a] Having an uncertainty range from one-tenth of the mean value to ten times the mean value.

Source: Expert judgement

4.3.2.2 COKE PRODUCTION

Coke is produced by the pyrolysis of coal. Coal pyrolysis at high temperature is called carbonisation. The processes produces coke, volatile compounds and a range of gases. Coke is the most important reducing agent in hot metal production and removes the oxygen either indirectly by forming carbon dioxide or directly using its inherent carbon content. In the coke production process, the temperature of the flue-gases from under firing is normally 1150 – 1350 °C indirectly heating the coal up to 1 000 – 1 100°C for 14 – 28 hours (JRC, 2013). The gasification of the coke also serves to supply the heat necessary for the reduction process. Coke functions both as a support material and as a matrix through which gas circulates in the stock column.

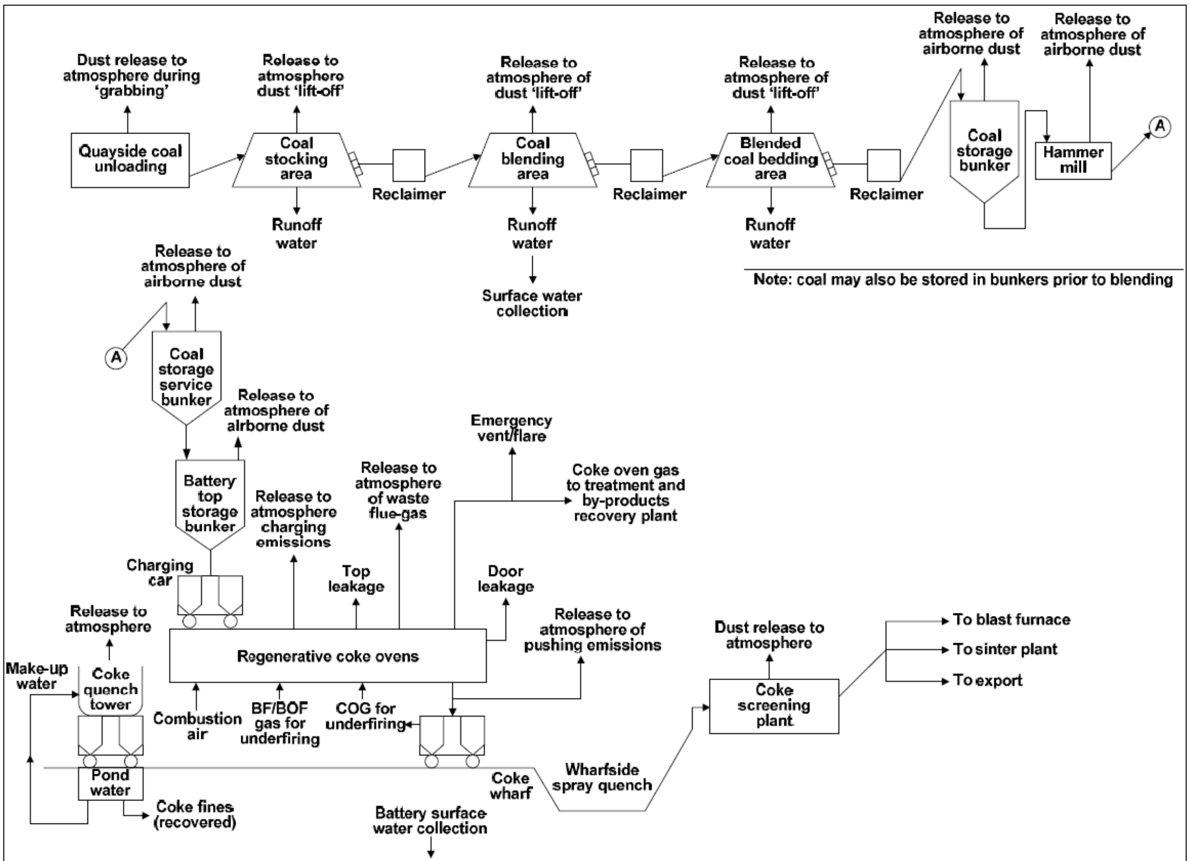
Globally the production of coking coal and associated COG is significant. In 2014, 711 173 ktoe of coking coal were produced.

Only certain coals, for example coking or bituminous coals, with the right plastic properties, can be converted to coke and, as with ores, several types may be blended to improve blast furnace productivity and extend coke battery life. Other materials which contain carbon can also be applied in small quantities (e.g. petroleum coke, used crushed rubber tyres). Oil or oil residues are added to give a better compaction of the coal.

Since the 1940s, the coke production process has been mechanised and the materials used in the construction of the ovens have been improved without significant design modifications. Horizontal chamber coking is the common coke plant. Batteries may contain up to 70 ovens as large as 14 m long and 6 m high. Because of heat transfer considerations, widths have remained at between 0.3 and 0.6 m. Each oven in the battery holds up to 30 tonnes of coal. Some recently constructed coke oven plants have increased dimensions further. ‘Heat recovery’ (non-recovery) coke making gained importance during recent years, although this technique is not applied in Europe to date. Heat recovery coke making needs oven systems which differ clearly in design when comparing with conventional horizontal chamber systems (JRC, 2013).

Figure 4.3.2 shows a typical flow diagram of a coke oven plant showing all sources of emissions.

Figure 4.3.2 Typical flow diagram of a coke oven plant showing emissions sources



Source: [148, UK Coke 1995]

The coke-making process can be subdivided into several stages. Fugitive emissions of varying intensities are possible at each of these stages:

- coal handling and preparation;
- battery operation (coal charging, heating/firing, coking, coke pushing, coke quenching);
- coke handling (discharge, storage, conveyance) and preparation;
- coke oven gas (COG) treatment with recovery and treatment of by-products in the case of a conventional coking plant recovery of the heat of the cooking and treatment of the flue gas in the case of a heat recovery coking plant.

METHODOLOGICAL ISSUES

CHOICE OF METHODS, DECISION TREES, TIERS

There are many potential sources of fugitive emissions from the coking process. Table 4.3.4 provides a summary of likely emissions according to coke production processing stage.

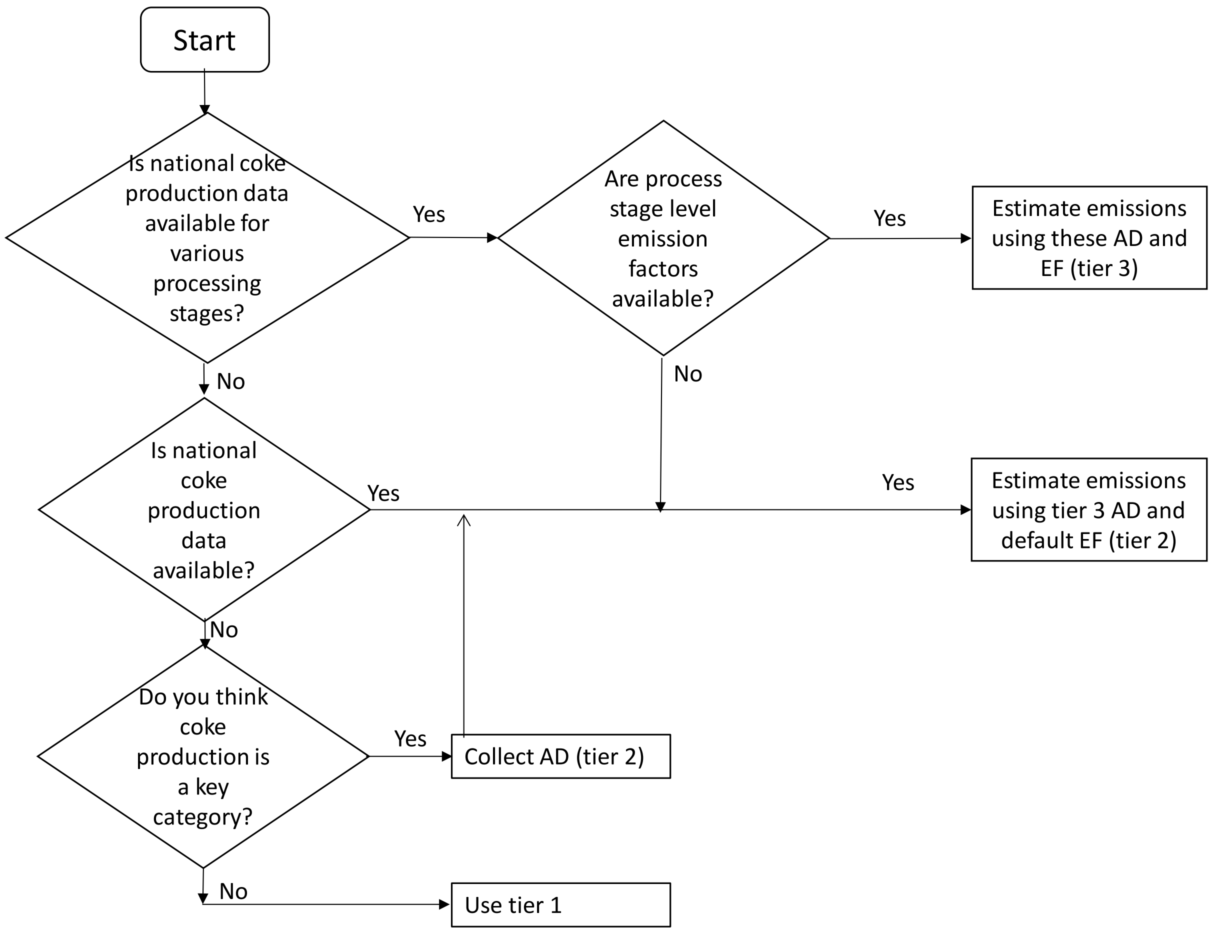
TABLE 4.3.4
COMMENTARY ON FUGITIVE GREENHOUSE GAS EMISSIONS FROM COKE PRODUCTION ACCORDING TO PROCESSING STAGE

Coke production processing stage	**Summary of activity (operation)**	**Likelihood of fugitive emissions**			**Source and significance of fugitive emissions**	**Notes**
		CO_2	CH_4	N_2O		
coal handling and preparation	• The coke ovens are charged with pulverised coal • Stamp charging might be used to compact the coking coal	N	Y	N	• CH_4 emissions could be significant, especially from gassy coal	• Emissions of CH_4 from gassy coal in storage prior to use in the coking ovens are not considered as part of this methodology • These emissions should be considered as part of coal handling and storage
heating/firing of the chambers	• The individual coke oven chambers are separated by heating walls • In order to improve energy efficiency, regenerators are located directly under the ovens, exchanging heat from flue-gases with combustion air and/or process gases (COG)	N	P	N	• CH_4 emissions could occur, especially from gassy coal • Emissions might occur if the heating walls are not completely gas-tight	• If the heating walls are not completely gas-tight because of cracks, coke oven gas produced during coking will reach the flue-gas and will cause incomplete combustion resulting in emissions at the stack
coking	• The complete coking process takes around 14 – 28 hours, depending e.g. on the width of the oven (in case of heating by the side), the density of coal and on the quality of the desired coke (e.g. use in foundries or blast furnaces)	P	P	P	• Fugitive emissions could occur through leakage of unburnt COG because of poor sealing in the coke batteries, particularly around the door seals, and, from any flaring of the COG produced • N_2O and CO_2 would only be released from flaring of COG • The magnitude of the emissions could vary from insignificant to perhaps 5% of the COG produced	• Emissions from the fuel used to heat the coke batteries should be reported in the energy sector using the methodologies set out in the stationary combustion chapter • Coke yield and COG production and composition depend, to a large extent, on coal composition and coking time

TABLE 4.3.4
COMMENTARY ON FUGITIVE GREENHOUSE GAS EMISSIONS FROM COKE PRODUCTION ACCORDING TO PROCESSING STAGE

Coke production processing stage	Summary of activity (operation)	Likelihood of fugitive emissions			Source and significance of fugitive emissions	Notes
		CO_2	CH_4	N_2O		
coke pushing	• Fully-carbonised coke is pushed out of the oven into a container by the ram of the pusher machine usually in less than one minute	N	P	N	• Possibility of very small emissions of CH_4 as the coke is pushed out of the batteries from residual COG in the coke batteries	• Fugitive emissions from this activity will be very small relative to the other likely fugitive emissions from coke production
coke quenching	• Wet quenching and dry quenching techniques can be used • Wet quenching consumes large volumes of water. The temperature of the coke is reduced from 1 100 to 80 °C to avoid combustion • For dry quenching, the quenching car takes the hot coke to a vertical quenching chamber. Inert quenching gas circulates around the chamber, which is isolated from the atmosphere, preventing combustion whilst cooling the coke. The gas is cooled by a heat exchanger in order to recover thermal energy	N	U	N	• Possibility of very small emissions of CH_4 from residual COG as the coke is pushed out of the batteries	• Fugitive emissions from this activity will be very small relative to the other likely fugitive emissions from coke production

Figure 4.3.3 Decision tree for estimating fugitive emissions from coke production process



Fugitive emissions can occur during coking operations from leakages at the battery, for example, because of leakage from vessels, oven doors, flanges, or at the by-product plant. Fugitive emissions occur also from the ascension pipe and charging hole sealings. The magnitude of these emissions will depends on the coke oven technology and the level of maintenance. The variability in the magnitude of fugitive emissions will be large.

Specific door emissions vary widely depending upon the type of doors, the size of ovens and the quality of maintenance. Maintenance can be a determining factor. Examples of good results with traditional (knife-edged) doors on well-maintained small ovens and poor results with modern flexible sealing doors on poorly maintained large ovens can be found (Eurofer, 2007).

Because of the high expenditure for leakage monitoring, there is very little actual data available for fugitive emissions caused by battery operation.

The general form of the equation for estimating emissions for a Tier 1 approach, based on coke production activity stage and activity at each stage, is given by Equation 4.3.2 below.

EQUATION 4.3.2
FUGITIVE GHG EMISSION FROM COKE PRODUCTION

$$Emissions_{GHG,\ charcoal\ produced} = Activity_{coke\ production\ \ processing\ stage} \bullet Emission\ Factor_{GHG}$$

Where:

Emissions GHG, activity = emissions of a given GHG by coke production processing stage

Activity = amount of activity [units]

Emission Factor GHG = emission factor according to coke production processing stage, and GHG

In a Tier 3 approach, the inventory compilers could use emission measurement data for one or more of the coke processing stages, or, possibly use a detailed fugitive predictive emission model. Any models should be verified. If measurements of fugitive emissions are used, it is *good practice* for inventory compilers to explain the rationale behind the emission measurement campaign, how measurements were made, and, if the measurements are applicable to individual coke batteries only or can be applied more widely to other batteries in the country also. Any measurement campaigns should focus on the sources in Table 4.3.4 associated with the greatest likelihood of emissions.

Coking coal in storage prior to being used in coke batteries may degas and release CH_4. The guidance in this section does not cover the release of CH_4 from gassy coal. However, inventory compilers should be aware of the possibility of emissions from this source and estimate and report emissions to the guidance in section 4.1.

CHOICE OF EMISSION FACTOR

Currently there are no fugitive emission factors [of CH4 and N2O] from coke production which are sufficiently reliable to present as Tier 1 factors. If inventory compilers have measurements of emissions from either parts or all of the coke production processing stages, then these could be used as the basis of reported fugitive emissions. It is good practice to try and verify these emissions to ensure that they are realistic in magnitude in comparison with emissions from other categories in the iron steel sector, and the energy sector.

CHOICE OF ACTIVITY DATA

The quantities of coke produced may form the input to methods used to estimate fugitive emissions. Coke production data is normally available in national energy balance data. Plant specific coke production data may also be available.

UNCERTAINTY ASSESSMENT

The quantities of coke produced are likely to be [relatively] well known. Uncertainty estimates of production may be available from energy balance data, or, from plant operators. Fugitive emissions of CH4 and N2O will be highly uncertain, and, order of magnitude uncertainties on emissions are likely and can be assumed as a first approximation.

4.3.2.3 SOLID (FUEL) TO SOLID (FUEL) TRANSFORMATION

Biomass is the fourth largest source of energy worldwide and provides basic energy requirements for cooking and heating of rural households in developing countries. Biomass densification has aroused a great deal of interest in recent years as a technique to enhance the use of residues as energy source. The densified biomass produced is mostly in the form of briquettes in developing countries and in the form of pellets in developed countries. Among the solid fuel products of densification are: wood briquettes, patent fuel, brown coal briquettes, wood pellets and peat briquettes.

Global production of pellets was approximately 21.6 million tonnes in 2013. The top five pellet producing countries were the US (5.0 million tonnes), Canada (2.4 million tonnes), Germany (2.2 million tonnes), Sweden (1.4 million tonnes) and Latvia (1.1 million tonnes), yielding over 50% of the world's wood pellets (FAO, 2015). In 2013, the EU produced 11 million tonnes and consumed 17 million tonnes. The 6 million tonnes of pellets imported by the EU come mainly from the United States, Canada and Russia, and were largely used in industrial power generation. EU wood pellet imports have grown dramatically over the years from 1.7 million tonnes in 2009 to 7 million tonnes in 2015, with the largest imports coming from North America (62% of all imports in 2009 and 79% in 2015). Canada was the largest exporter to the EU until 2012, when the US took over top spot (European Union, 2017).

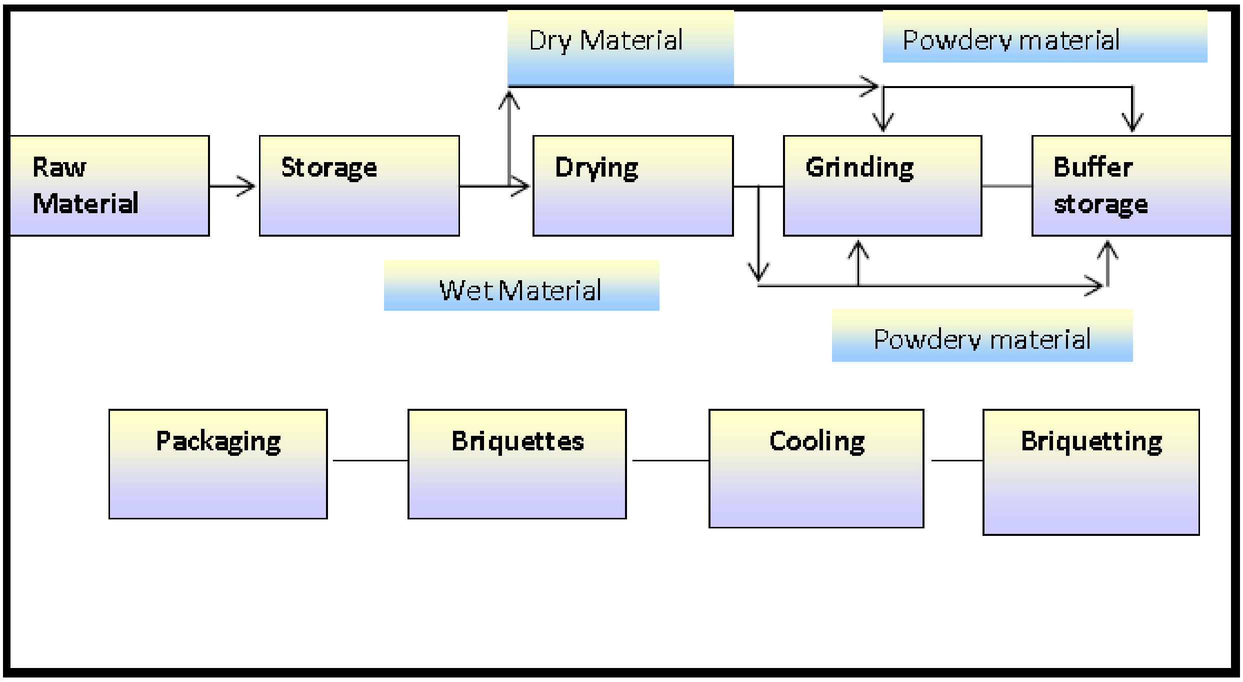
Wood pellets are made from compacted sawdust from cut trees or wastes from sawmilling and other wood product manufacture.

During the various stages in the briquette and pellet production, fugitive emissions of gases occur. These fugitive gases include direct and indirect greenhouse gases: CH_4, CO_2, CO, and volatile organic compounds (VOCs).

Fugitive gases typically emitted from pellet storage include direct and indirect GHGs: CH_4, N_2O, CO, CO_2, and other VOCs.

The process of briquette or pellet production follows the various stages indicated in Figure 4.3.4.

Figure 4.3.4 Flow diagram of briquette production process



Note: Source: Grover and Mishra, 1996

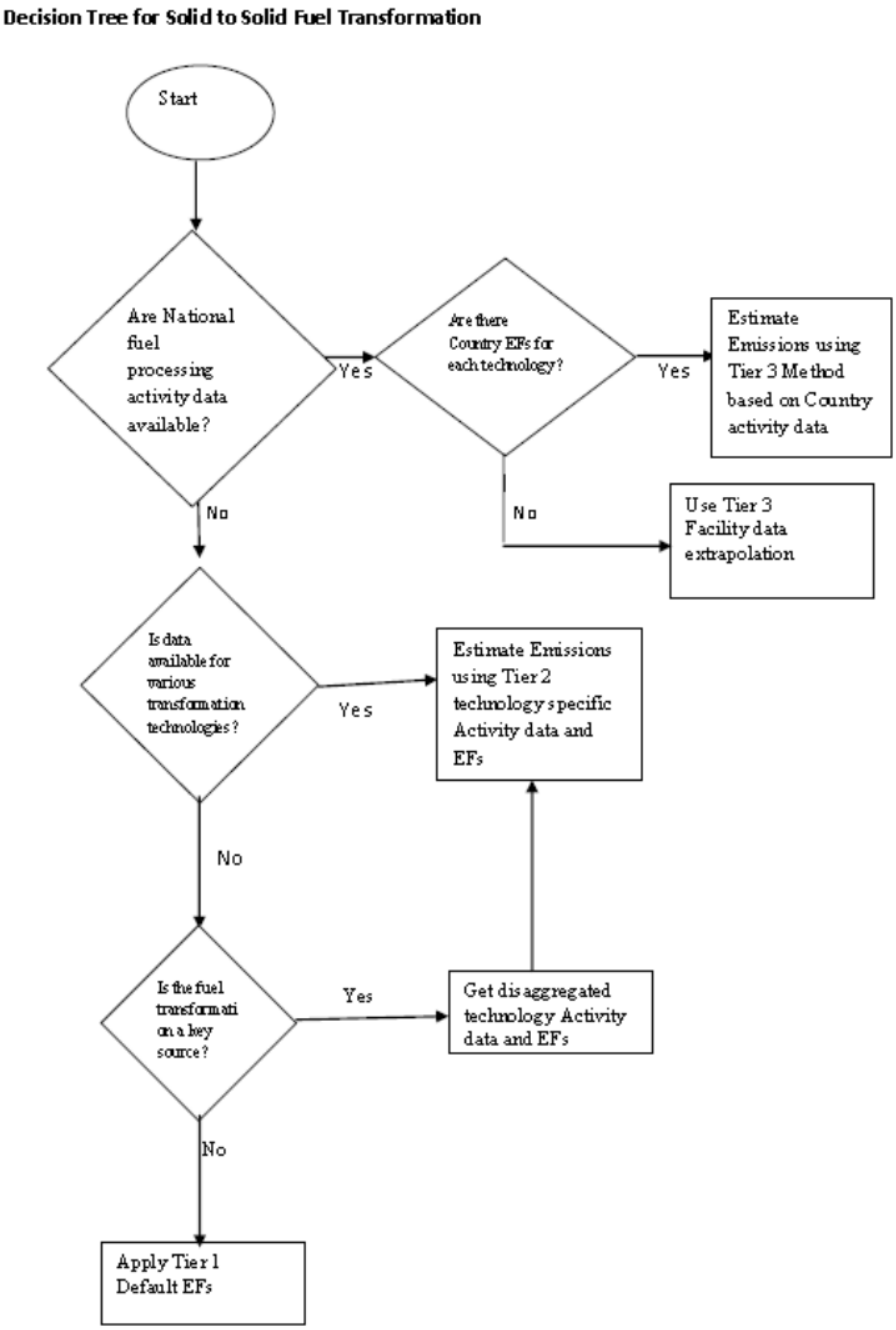
METHODOLOGICAL ISSUES

CHOICE OF METHODS, DECISION TREES, TIERS

[Fugitive emissions of CO_2 should not be estimated or reported from this category.]

The choice of the method for estimating the fugitive emission depends on the nature and level of disaggregation of activity data and emission factors available [in the country]. Where there is no country or technology specific data, a Tier 1 method can be applied to estimate emissions using default emission factors. In the case where country specific emission factors are available but the activity data are not disaggregated by each transformation technology, a Tier 2 method can be applied. Finally, where technology specific data and emission factors are available, a Tier 3 method can be used. The decision tree for estimating emissions from solid to solid fuel transformation is given in Figure 4.3.5.

Figure 4.3.5 Decision tree for estimating emissions from solid to solid fuel transformation



CHOICE OF EMISSION FACTOR

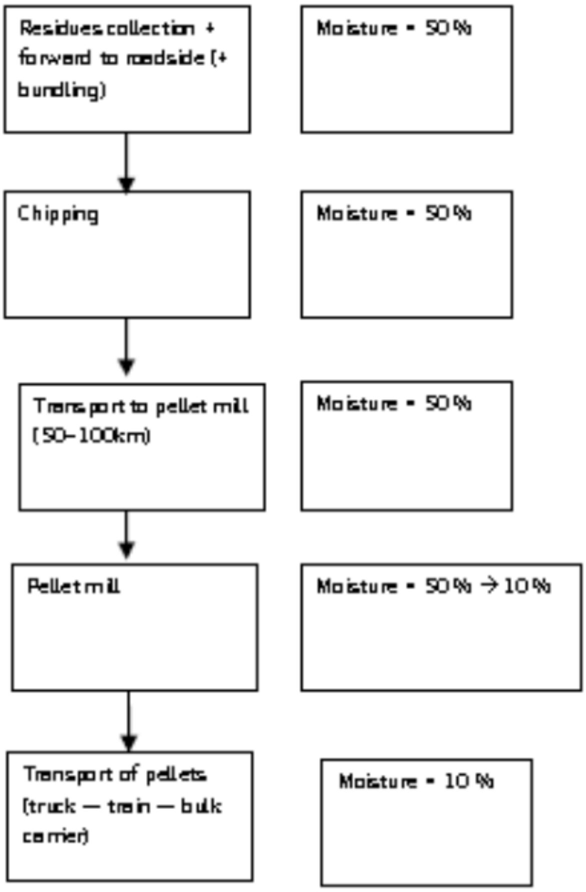
The fugitive emissions for each transformation of solid to solid products arise from material handling during storage, drying and transport operations. Fugitive emissions from four sources of pellet production need to be considered:

1. Pellets from forest logging residues;
2. Pellets from wood industry residues;
3. Pellets from stem wood; and,
4. Pellets from agricultural residues.

It is *good practice* for inventory compilers to identify which of these production pathways exist in their country, and their absolute and relative magnitudes.

Generally, five steps can be identified in the wood pellet production pathway are shown in Figure 4.3.6. In order to avoid possible double counting of emissions from the pellet production, it is recommended that inventory compilers cross-check to ensure inventories in the AFOLU and waste sector may have touched on some of the steps in the pathway or alternatively restrict to emissions from the pelleting process at the pellet mill.

Figure 4.3.6 Wood pellets pathway



Emission factors for fugitive emissions from wood chip and pellet production, and agricultural system, according to biomass system and distance of transport, are presented in Tables 4.3.5 to 4.3.10. Table 4.3.11 shows a summary of default emission factors of pellet production using various feedstocks and processes in the cases where there are no country-specific emission factors.

TABLE 4.3.5
PROCESS FOR THE PRODUCTION OF PELLETS FROM FRESH WOODCHIPS

Production of wood pellets & briquettes from fresh forest chips: moisture ~ 50 %, and final pellet moisture 10 %

	I/O	Unit	Amount	References
Woodchips	Input	MJ/MJwood pellets	1.01	4
Electricity	Input	MJ/MJwood pellets	0.050	5
Heat	Input	MJ/MJwood pellets	0.185	1,2
Diesel	Input	MJ/MJwood pellets	0.0020	1,3
Wood pellets	Output	MJ	1.00	7
CH4	Output	g/MJpellets	1.53E-06	6
N2O	Output	g/MJpellets	6.40E-06	6

1. Hagberg et al.,2009
2. Obernberger, I. and Thek, G., *The Pellet Handbook*, 2010
3. Mani, 2005
4. Sikkema et al., 2010
5. Ryckmans, 2012
6. EMEP/EEA Guidebook 2013, Chapter 1.A.4.c.ii - Tier 1 - Table 3-1 – Forestry
7. Giuntoli et al, 2015

TABLE 4.3.6
PROCESS FOR THE PRODUCTION OF PELLETS FROM A MIX OF WET AND DRY RESIDUES

Production of wood pellets & briquettes from wood industry residues

	I/O	Unit	Amount	References
Sawdust	Input	MJ/MJwood pellets	1.01	5
Electricity	Input	MJ/MJwood pellets	0.028	1, 3, 4
Heat	Input	MJ/MJwood pellets	0.111	1, 2
Diesel fuel	Input	MJ/MJwood pellets	0.0016	1, 3
Wood pellets	Output	MJ	1.00	7
CH_4	Output	g/MJpellets	1.23E-06	6
N_2O	Output	g/MJpellets	5.12E-06	6

1. Hagberg et al., IVL, 2009;
2. Obernberger and Thek, 2010;
3. Mani, S., 2005;
4. Christian Rakos, Propellets Austria, personal communication, 27 June 2011.
5. Sikkema et al., 2010.
6. EMEP/EEA Guidebook 2013, Chapter 1.A.4.c.ii - Tier 1 - Table 3-1 – Forestry
7. Giuntoli et al, 2015.

TABLE 4.3.7
PROCESS FOR FOREST RESIDUES COLLECTION

Forestry residues collection including stump harvesting and chipping

	I/O	Unit	Amount	References
Wood	Input	MJ/MJwoodchips	1.00	2
Diesel	Input	MJ/MJwoodchips	0.0120	1
Woodchips	Output	MJ	1.00	1
CH_4	Output	g/MJwoodchips	9.20E-6	3
N_2O	Output	g/MJwoodchips	3.85E-5	3

1. Hagberg et al., IVL, 2009;
2. Obernberger and Thek, 2010;
3. Mani, S., 2005;
4. Christian Rakos, Propellets Austria, personal communication, 27 June 2011.
5. Sikkema et al., 2010.
6. EMEP/EEA Guidebook 2013, Chapter 1.A.4.c.ii - Tier 1 - Table 3-1 – Forestry.

TABLE 4.3.8
PROCESS FOR WOODCHIPPING

Woodchipping

	I/O	Unit	Amount	References
Wood	Input	MJ/MJwoodchips	1.025	1,2
Diesel	Input	MJ/MJwoodchips	0.00336	1
Woodchips	Output	MJ		1
CH_4	Output	g/MJwoodchips	2.57E-06	3
N_2O	Output	g/MJwoodchips	1.07E-05	3

1. Lindholm et al., 2010.
2. Sikkema et al, 2010.
3. EMEP/EEA Guidebook 2013

TABLE 4.3.9
TRANSPORTATION SCHEME FOR PELLETS PATHWAYS

	Total travel-distance range	Truck (chips)	Truck (pellets)	Train	Ship	Notes
Pellets pathways	1–500 km	50	500			Intra-EU
	500 – 2500 km	50	250		2 000	E.g. Russia
	2500–10 000 km	50	200		8 000	E.g. Brazil
	Above 10 000 km	100		750	16 500	E.g. Western Canada

Reference: Giuntoli et al, 2015

TABLE 4.3.10 **PROCESS FOR AGRI-RESIDUES PREPROCESSING** Baling/processing				
	I/O	**Unit**	**Amount**	**References**
Agri-residue	Input	MJ/MJbale	1.0	1
Diesel	Input	MJ/MJbale	0.010	1
Bales	Output	MJ	1.0	1
CH_4	Output	g/MJbale	1.23E-05	2
N_2O	Output	g/MJbale	3.03E-05	2

1. GEMIS v. 4.9, 2014, Xtra-residue\straw bales-DE-2010.
2. EMEP/EEA Guidebook 2013, Chapter 1.A.4.c.ii - Tier 1 - Table 3-1 – Agricultural Machines.

TABLE 4.3.11 **SUMMARY OF GHG EMISSIONS FROM PELLET PRODUCTION USING VARIOUS FEEDSTOCKS AND /OR PROCESSES**			
	CH4	**N2O**	**Data source**
Feedstock			
Forest logging residues	1.53E-06 (g/MJpellet)	6.40E-06 (g/MJpellet)	1
Wood industry residues	1.23E-06 (g/MJpellet)	5.12E-06 (g/MJpellet)	1
Agricultural residues	1.23E-05	3.03E-05	1
Processes			
Forest residues collection	9.20E-6 g/MJwoodchips	3.85E-5 g/MJwoodchips	2,3
Wood chipping	2.57E-06 g/MJwoodchips	1.07E-05 g/MJwoodchips	1
Agri-residues preprocessing	3.03E-05 g/MJbale	3.03E-05 g/MJbale	1

Sources:
1. EMEP/EEA Guidebook 2013.
2. Lindholm et al., 2010.
3. Sikkema et al., 2010.

CHOICE OF ACTIVITY DATA

The activity data to enable the estimation of fugitive emissions from solid to solid fuel transformations includes:

- Quantity of solid biomass input materials available for processing;
- Quantity of final products (briquettes or pellets).

UNCERTAINTY ASSESSMENT

The quantities of wood pellets produced are likely to be [relatively] poorly known. Uncertainty estimates of production may be available from energy balance data, or, from pellet producers. Fugitive emissions of CH_4 and N_2O will be highly uncertain, and, order of magnitude[6] uncertainties on emissions are likely and can be assumed as a first approximation.

[6] Having an uncertainty range from one-tenth of the mean value to ten times the mean value.

4.3.2.4 GASIFICATION TRANSFORMATION PROCESSES

This section covers the fugitive emissions from a range of sources where greenhouse gases are produced from the gasification of fuels. This conversions include:

1. biomass to liquid;
2. biomass to gaseous;
3. coal to liquid;
4. gas to liquid.

Some of these technologies are "emerging technologies", and not yet widespread. However, it is likely that they will become more widely adopted and methodologies have therefore been included so inventory compliers can use them to estimate fugitive emissions.

BIOMASS TO GASEOUS AND BIOMASS TO LIQUID

Biomass to gaseous (BtG) is a process where biomass is gasified with oxygen and steam to produce a synthetic gas, the syngas, composed of H_2, CO, CO_2 and CH_4. This gas can be used as a fuel, to generate electricity through a gas turbine, as a chemical feedstock or as a feedstock to the biomass to liquid technology (IEA Bioenergy, 2005; OCDE/IEA, 2007).

In the biomass to liquid conversion (BtL), after the gasification process, the syngas is cleaned to remove CO_2 and CH_4 and, then, transformed, by a Fisher Tropsch (FT) process, on long chain hydrocarbons with different molecular weights, resulting in high quality green fuels like gasoline, diesel, aviation turbine fuels, [called as FT fuels].

A variety of biomass types can be used as inputs, for example, woody biomass, waste biomass (sorted municipal, commercial waste), agricultural and forest waste. It is important to highlight that currently, most of BtG and BtL plants are either on demonstration scale or pilot scale. Hence, there is minimal literature describing research into the emissions from the processes (IEA Bioenergy, 2006; OCDE/IEA, 2007; AIL, S.S.; DASAPPA, S., 2016; NETL/DOE, 2016).

The biomass used in these processes does not have any carbon of fossil origin and so CO_2 fugitive emissions resulting in the process are biogenic emissions and should be reported as an information item in greenhouse gases inventories. [As highlighted at Waste Volume of the *2006 IPCC Guidelines*, if combustion, or any other factor, is causing long term decline in the total carbon embodied in living biomass (e.g., forests), this net release of carbon should be evident in the calculation of CO_2 emissions described in the Agriculture, Forestry and Other Land Use (AFOLU) Volume of the *2006 IPCC Guidelines*.]

COAL TO LIQUIDS

Synthesis gas from CTL is generated by feeding coal into a gasification process. This synthesis gas containing a mixture of carbon monoxide, hydrogen, carbon dioxide and methane is fed into a gas cleaning process where impurities such as sulphur bearing compounds (in particular hydrogen sulphide), and heavy metal bearing compounds are removed from the synthesis gas. After cleaning, the synthesis gas composition is adjusted in a process called water-gas shift conversion. Here the ratio of hydrogen to carbon monoxide is adjusted to produce a synthesis gas which is optimal for Fischer-Tropsch synthesis.After water-gas shift conversion the modified synthesis gas is fed to the Fischer-Tropsch synthesis process where it reacts to produce liquid hydrocarbons. A significant fraction of CTL plan CO_2 is generated in the gasification process which needs to be seprated before the syngas is fed into the FT reactor (Mantripragada and Rubin, 2011). Current production levels mainly from CTL plants are estimated at over 300 000 Barrels Per Day (BPD) with a conservative estimate of 120 million tons of CO_2 equivalent.

GAS TO LIQUIDS

Natural gas is combined with steam and pure oxygen from a cryogenic air separation unit before it is heated and fed into an autothermal reformer (ATR). Syngas, a mixture of H2 and CO, leaves the ATR and enters the FischerTropsch (FT) synthesis reactor, where it is converted to a hydrocarbon wax. The wax exiting the FT reactor is upgraded in the product work-up unit to yield approximately 70% diesel and 30% naphtha liquid products. A steam-methane reforming hydrogen plant is required to provide hydrogen for the product upgrading as well as inlet natural gas pre-treatment. The GTL plant CO2 is generated from several sources (Heimel & Lowe, 2009):

- Entering with the inlet natural gas (feed gas assumed to contain 1.6 mol% CO_2)
- Forming during syngas generation

- Forming in the FT reactor
- Forming in the hydrogen plant
- Forming in the process heating furnaces

GTL technology in particular as alternative to petroleum based diesel is considered to be one of the most the technical options to reduce petroleum consumption in the on-road transportation sector (Hao et al, 2010). The worldwide syngas database produced by the Gasification and Syngas Technologies Council (GSTC) shows that there are more than thirty (30) projects that are either in operation or under development (GSTC, 2014). Hao et al estimated GTL capacity to be 35,000 BPD in the year 2010 and projected an increase in capacity to 1-2 million BPD by 2015 (Hao et al, 2007).

TABLE 4.3.12
SUMMARY OF GHG EMISSIONS FROM CTL AND GTL PROCESSES

Synthetic fuel production Process	**GHGs**
CTL	CO_2, CH_4, N_2O
GTL	CO_2

METHODOLOGICAL ISSUES

The choice of method will depend on the technologies that are operational in countries, [including whether the technologies analyzed in this section are key categories in the country], and to what extent country and plant-specific information is available or can be gathered.

The most accurate emission estimates and, therefore, the fugitive emissions, can be developed by determining the emissions on a plant-by-plant basis and/or differentiated for each feedstock category (e.g., type of biomass, coal or gas). The methods for estimating CO_2, CH_4 and N_2O fugitive emissions from these technologies vary because of the different factors that influence emission levels. N_2O emissions from coal gasification are negligible and depends on the nitrogen content of the coal.

The general approach to calculate greenhouse gas emissions from those technologies is to obtain the amount of feedstock used and to investigate the related greenhouse gas emission factors, preferably from country-specific information on the carbon content.

To estimate fugitive CO_2 emissions, it will be necessary to:

- Identify types of biomass used as feedstock (wood, waste biomass (sorted municipal and/or commercial waste) or agriculture and forest residue);
- Compile data on the amount of feedstock used (e.g. amount of syngas, natural gas input);
- Use default values provided on dry matter content, total carbon content and fossil carbon fraction;
- Use default density at standard temperature and pressure for natural gas to convert the amount of natural gas inputs from volumetric basis to mass basis;
- Carbon mass flows and species composition of each carbon mass flow stream in CTL and GTL plants for tier 3 approach.

CHOICE OF METHODS, DECISION TREES, TIERS

There is limited information about gasification transformation technologies and, therefore, it was considered that fugitive emissions occur only at the gasification stage. The fugitive emissions resulted from the syngas transformation at the Fischer and Tropsch stage was considered negligible, as it is an energy related processes.

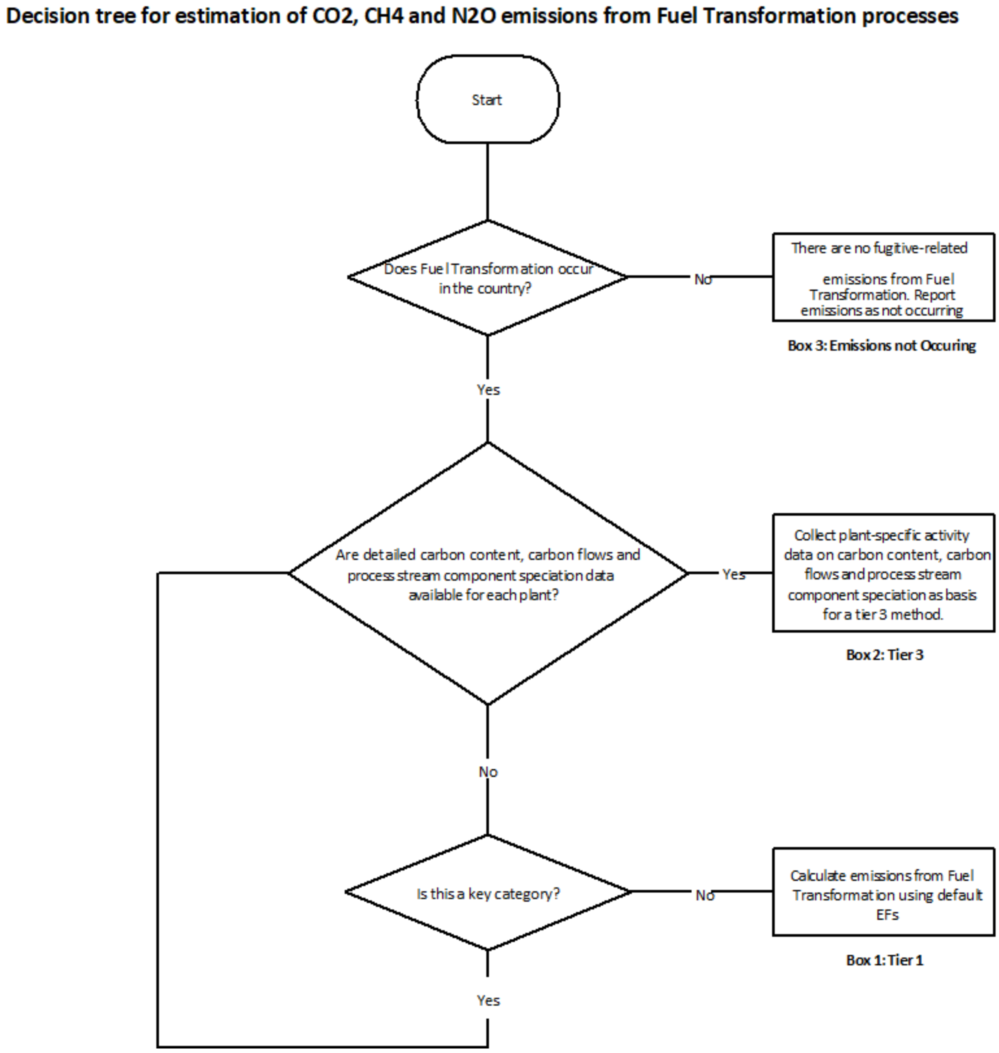
The method for estimating fugitive emissions from biomass to liquid, biomass to gaseous, coal to liquid and gas to liquid technologies is based on an estimate of the carbon content in the feedstock combusted and converting the product to greenhouse gases emissions.

The activity data are the feedstock inputs into the gasification stage, and the emission factors are based on the carbon content of the feedstock that is of fossil origin.

As BtG and BtL are still emerging technologies, and there are currently very few large scale plants worldwide, and so methodologies to calculate Tier 2 and Tier 3 are not provided. Inventory compilers could choose to use higher Tier methods to estimate emissions, but they need to transparently document the approaches used and state how their methods accurately and completely estimate emissions.

The choice of method depends on the country specific information available, and is given in the decision tree in Figure 4.3.7.

Figure 4.3.7 Decision tree for estimating emissions from fuel transformation processes



TIER 1

The Tier 1 method is a simple method which can be used when fugitive emissions from biomass to liquid, biomass to gaseous, coal to liquid and gas to liquid technologies are not a *key category*.

Data on the amount of feedstock and carbon content are necessary. The calculation of the fugitive emissions are based on an estimation of the amount of feedstock (wet weight) taking into account the dry matter content, the total carbon content, the fraction of fossil carbon and the emission factor of fugitive emission. The application of a Tier1 approach is done using Equation 4.3.3 presented below.

Default data on characteristic parameters (such as dry matter content, carbon content and fossil carbon fraction) for municipal and industrial waste are provided in Table 5.2 in chapter 5 and Tables 2.3 to 2.6 in Section 2.3 in Chapter 2 of Waste Volume.

EQUATION 4.3.3
FUGITIVE GHG EMISSIONS FROM [GASIFICATION PROCESSES]

$$E_{gas,\ technology\ i} = \sum (FSi \cdot CF_i \cdot FCFi \cdot EFi) \cdot 10^{-6}$$

Where:

$E_{gas\ i}$ = Direct amount (Gg/yr) of GHG gas i emitted at gasification station of BtL, BtG, CtL and GtL facilities (CO_2, CH_4, N_2O)

FSi = total amount of feedstock of type i (wet weight) (Gg/yr)

CF_i = Fraction of carbon in the feedstock (total carbon content), (fraction)

FCF_i = fraction of fossil carbon in the total carbon, (fraction)

EFi = aggregate gas i emission factor, kg gas i/Gg of feedstock j

10^{-6} = convertion factor from kilogram to gigagram

As highlighted at Waste Volume, for MSW, it is *good practice* to calculate the fugitive emissions on the basis of waste types/material (such as paper, wood, plastics) in the MSW gasified at BtG or BtL technologies as shown in equation 4.3.4, adapted from equation 5.2 from Waste Volume.

EQUATION 4.3.4
FUGITIVE EMISSIONS BASED ON WASTE COMPOSITION

$$E_{gas,\ technology\ i} = FSi \bullet \sum (WFj \bullet dmj \bullet CF_i \bullet FCFi \bullet EFi) \bullet 10^{-6}$$

Where:

$E_{gas\ i}$ = Direct amount (Gg/yr) of GHG gas *i* emitted at gasification station of BtL and BtG (CO_2, CH_4, N_2O)

FS_i = total amount of feedstock of type *i* (wet weight) (Gg/yr)

WF_j = fraction of waste type/material of component *j* of the MSW (wet weight)

dm_j = dry matter content in the component *j* of the MSW gasified, (fraction)

CF_j = fraction of carbon in the dry matter (i.e., carbon content) of component *j*

FCF_i = fraction of fossil carbon in the total carbon, (fraction)

EF_i = aggregate gas *i* emission factor, kg gas i/Gg of feedstock *j*

10^{-6} = conversion factor from kilogram to gigagram

If data by waste type/material are not available, the default values for waste composition given in Section 2.3 Waste composition, of Waste Volume, could be used.

TIER 2

CTL and GTL plants are versatile and depending on their process unit arrangement downstream. They are able to produce a wide range of products. Some CTL/GTL plants are able to produce a combination of liquid fuels and chemicals (e.g. Ammonia, Nitric Acid, methanol, etc). This in turn affects the rate at which syngas is produced upstream. The quality of coal used determines the quality of syngas and the effort needed to treat syngas. Hence, it is good practice to develop a tier 2 emission factor based on plant-specific emission factors as opposed to country-specific emission factors that are developed by aggregating plant-level emission factors for a country in question

TIER 3

The most appropriate tier 3 approach is a material balance methodology. This is largely because, the CTL process in particular is a very versatile process. Depending on the type and volume of downstream products (chemicals or liquid fuels), the amount of syngas to be processed via the Fischer-Tropsch process can be varied. That in turn, affects the amount of syngas that needs to be produced upstream. The ultimately affects the amount of Greenhouse Gas emissions released in the atmosphere. Secondly, the syngas production and treatment processes release a large volume of flue gas stream that is almost impossible to measure. Hence, a direct measurement methodology is not ideal for CTL and GTL processes. Preferable a Tier 3 stoichiometric/mass-balance methodology should be followed.

CHOICE OF EMISSION FACTOR

Biomass to liquid and biomass to gaseous

The emission factor of gasification process of BtG and BtL are provided based on carbon content of biomass used in a selection of plants and the composition of its syngas, as analysed by Asadullah (2014), and considering 1% of fugitive emissions are release in the gasification stage.

TABLE 4.3.13
EMISSION FACTORS FOR GASIFICATION PROCESSES OF BTG AND BTL

	EF CH_4 (kgCH_4/ton C)	EF CO_2 (kg CO_2/ton C)	EF N_2O (kg N_2O/ton C)
Biomass	0.6	4	n.d.

n.d. – Not Determined

Source: estimated based on Asadullah (2014)

It was also considered that all the biomass is burned, in an other way, that there is no char formation.

Coal to liquids

Higman and van der Burgt (2008) presents process-specific CO_2, CH_4 and N_2O emission factors as a function of syngas production and by process type. It is worth noting that for the CTL process, the bulk volume of greenhouse gas emissions are released during the production and treatment of syngas. Table 4.3.10 presents emission factors reported by Higman and van der Burgt. These emission factors have been developed for typical current international values and ranges of coal qualities (20.700 -27.300 KJ/Kg HHV). Coal Gasification systems considered are the Air Separation Unit (ASU), Oxygen blown fixed-bed BGL 1000 gasifier, acid gas removal (Rectisol). Table 4.3.14 also provides CO_2 reduction factors for CTL plants with Carbon Capture and Storage (CCS).

TABLE 4.3.14
EMISSION FACTORS FOR GASIFICATION PROCESSES OF CTL

System Output	Syngas	Syngas/H2	SNG
CO_2 emissions, kt/PJtotal output	55	55	78
CH_4 emissions, kt/PJtotal output	0.0061	0.0061	0.0061
N_2O emissions, kt/PJtotal output	0 (only marginal emissions depending on the nitrogen content of the coal)	0 (only marginal emissions depending on the nitrogen content of the coal)	0 (only marginal emissions depending on the nitrogen content of the coal)
Reduction of CO_2 emissions if CCS is applied, %	up to 99%	up to 99%	up to 99%

References and Further Information

Higman, van der Burgt: “Gasification”, 2nd edition (2008); IEA Clean Coal Centre: “Coal to liquids”, Couch (2008); National Energy Technology Laboratory: “Industrial Size Gasification for Syngas, Substitute Natural Gas and Power Production”, “: “Gasification Industry Overview: Addressing the Dash to Gas”, Childress (2008); IEA Energy Technology Essentials: “CO2 Capture & Storage” (2006)

Gas to liquids

Jaramillo et al. analysed CO_2 emissions released during syngas production in CTL and GTL plants (Jaramillo et al, 2008). The study by Jaramillo et al (2008) assumes that slightly more diesel is produced than gasoline. This assumption is plausible given that a conventional GTL plant produces 62% Diesel, 44% gasoline and 3% propane. The CO_2 emission factor is therefore derived from the inputs and outputs of a conventional GTL plant by dividing the amount of carbon lost (assuming 100% oxidation) with the volume of natural gas input to produce syngas. CO_2 is the most dominant GHG in the GTL process and therefore, it is a conservative approach to assume that 100% of carbon lost to the atmosphere is CO_2.

TABLE 4.3.15
EMISSION FACTOR FOR GASIFICATION PROCESSES OF BTG AND BTL

Process	EF CO_2 (kgCO_2/TJ natural gas input)
Gas to liquids	6026

CHOICE OF ACTIVITY DATA

Biomass to liquid and biomass to gaseous

The actvity data required to estimate fugitive emissions from BtG and BtL includes the amount of biomass gasified at gasification stage. Countries that use these technologies should have plant-specific data on the amount of biomass gasified.

Coal to liquid

The actvity data required for a tiers 1 and 2 are the amounts of syngas produced in terajoules. Since this data is monitored continuously at individual plant level, it is good practice to collect syngas production data from each plant.

For the tier 3 method, carbon mass flow and species composition data is required to accurately quantify the amount of GHGs in the flue gas streams. Even though the amount of syngas produced is not necessary for a tier 3 method, it is good practice to to collect and report these data in compare the results of the tier 3 method (material balance) againsts the tier 1 method.

Gas to liquid

The actvity data required for a tiers 1 and 2 are the amounts of natural gas inputs into the GTL process in terajoules. Natural gas may be used upstream of the GTL plant for heat and electricity production during production. Therefore, it is good practice to ensure that the amount of natural gas used for electricity and heat during natural gas production is separated from the amount of natural gas used as a feedstock in the GTL plant.

For a tier 3 method, carbon flows and species composition is required to quantify the amount of carbon in each process stream and process unit inside a GTL plant. This information is monitoired continuously during process control and therefore should be readily available from each plant.

UNCERTAINTY ASSESSMENT

Fuel transformation processes

Estimates of fugitive emissions from all fuel transformation processes can be highly uncertain due to lack of information about these technologies. It is highly recommended more R&D on these technologies, especially direct measurement on all stages to confirm which ones present fugitive emissions.

Emission factor uncertainties

Considering the minimal literature and the absence of large scale fuel transformation processes, fugitive emission factors provided in this guideline were estimated based on a very few data, resulting in a high level of uncertainty.

Activity data uncertainties

Where activity data are obtained from plants, uncertainty estimates can be obtained from producers

4.3.3 Completeness

That this (new) section of the GLs is currently not able to provide a set of methods to estimate fugitive emissions from all the possible parts of each of the sources. But it is *good practice* for inventory compliers to ensure completeness and to try and estimate emissions if possible. But resources should be prioritised according to the key category analysis results.

4.3.4 Developing consistent time series

[Guidance will be provided in the second order draft]

4.3.5 Inventory Quality Assurance/Quality Control (QA/QC)

Specific QA/QC procedures to optimise the quality of estimates of emissions are given in in Chapter 6 of Volume 1, General Guidance and Reporting.

4.3.6 Reporting and Documentation

[Guidance will be provided in the second order draft]

Annex 4A.1 Standard Conditions

***NEW: PROVIDES CLARITY ON STANDARD CONDITIONS ***

Standard conditions

It should be noted that IPCC default EFs listed in the table (Table 4.2.3 – 4.2.13) are sensitive to temperature and pressure. Activity data must be consistent with the EFs standard conditions. The EFs are given at the most commonly used standard conditions: 15°C and 101.325 kPa (1 atm.). If activity data are derived at reference conditions, which are different from those used by IPCC default EFs, inventory compiler should harmonize activity data with 15°C and 101.325 kPa. Pressure is normally fixed for the most of the standard conditions at the level of 101.325 kPa (1 atm.). Thus, in general, probable variations of reference temperature should be considered as a priority.

Along with the physical state, activity data can be split into liquids (oil) and gases (natural gas and associated petroleum gas). Different recalculation approaches of gases and liquids are required.

Liquids (oil)

Liquids may be referenced at 20°C and 15°C. In order to harmonize oil units referenced at 20°C to IPCC default EFs adjusting can be made with the use of international standard tables of conversion factors (CFs) and densities, which is based on set of detailed data on oil properties and corresponded to internationally recognized sources as follows:

- ASTM D 1250-8 Standard Guide for Use of the Petroleum Measurement Tables issued by American Society for Testing and Material
- API MPMS 11.1:2004. American Petroleum Institute. Manual of Petroleum Measurement Standards Chapter 11 - Physical Properties Data Section 1 - Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils

As follows from the standard, recalculation approach is based on the equations listed below (equations 4A.1 to 4A.4) (GOST R 8.595-2010):

EQUATION 4A.1

$$\rho_{15} = \rho_{20} \cdot K_{15}$$

EQUATION 4A.2

$$\rho_{60/60} = \rho_{20} \cdot K_{60/60}$$

EQUATION 4A.3

$$\rho_{API} = \rho_{20} \cdot K_{API}$$

EQUATION 4A.4

$$V_{bbl} = M \cdot K_{bbl}$$

Where:

ρ_{15} = oil density at 20°C, kg/m^3;

ρ_{20} = oil density at 15°C, kg/m^3;

K_{15} = oil density at 20°C to oil density at 15°C conversion factor;

$\rho_{60/60}$ = relative oil density at 60°F (15.556°C);

ρ_{API} = API oil density, °API;

$K_{60/60}$ = oil density at 20°C to relative oil density at 60°F conversion factor 10^3(kg/m^3);

K_{API} = oil density at 20°C to relative oil API density conversion factor, °API/(kg/m^3);

M = oil mass, t;

K_{bbl} = oil mass (t) to oil volume (bbl) conversion factor bbl/t.

Uncertainties of recalculation approach are less than 0.01kg/m or 0.01°API, less than 0.01% of oil volume.

Gaseous (natural gas and APG)

Since for the most cases the pressure fixed at the 101.325 kPa (1 atm.), the temperature recalculation can be performed as follows (equation 4A.5).

EQUATION 4A.5

$$V_{st} = V_g \cdot CF_t$$

Where:

V_{st} = gas volume at the required reference conditions, m^3;

V_g = gas volume at the given reference conditions, m^3;

CF_t =conversion factor, dimensionless.

According to the equation, initial gas volume should be multiplied by the conversion factor to obtain the gas volume at the required temperature. The factors are derived by means of ideal gas equation at the pressure fixed at the level of 101.325 kPa (1 atm.). The conversion factors are shown at the table 4A.1.

TABLE 4A.1
RECALCULATION OF GAS VOLUMES TO THE REQUIRED TEMPERATURE CONVERSION FACTORS (CFT)

To / From	0°C	15°C	20°C
0°C	1	1.055	1.073
15°C	0.948	1	1.017
20°C	0.932	0.983	1

The difference between ideal and real volumes of APG and NG is within 0.55%. Such difference express uncertainty of the recalculation.

Annex 4A.2 Disaggregation of Tier 1 factors presented in section 4.2.2.3

***NEW: PROVIDES METHOD AND VALUES TO DISAGGREGATE THE AGGREGATE EFS PRESENTED IN 4.2 ***

This Annex presents the percent of emissions that are leaked, vented, and flared in the data sets used for the Tier 1 emission factors. To disaggregate the aggregate Tier 1 EF in the *2019 refinements*, apply the % below to the corresponding aggregated value presented in section 4.2. The disaggregation is presented for factors which included disaggregation in the *2006 IPCC Guidelines*.

***Note to reviewers: Some of the underlying data sets used to develop emission factors presented here may be updated after the release of the FOD. Emission factors developed from those data sets may be recalculated to reflect the latest information. ***

TABLE 4A.2
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR OIL PRODUCTION SEGMENT, 1.B.2.A.III.1

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	

Onshore Production	Most activities occurring with higher-emitting technologies and practices	Leaks	5%	ND	1%	ND	ND	ND	ND	ND	Apply percentages to applicable EF (EF based on either onshore oil production, or active oil well)
		Vents	91%	ND	99%	ND	ND	ND	ND	ND	
		Flares	4%	ND	-	ND	ND	ND	ND	ND	
Onshore Production	Most activities occurring with lower-emitting technologies and practices	Leaks	8%	ND	1%	ND	ND	ND	ND	ND	Apply percentages to applicable EF (EF based on either onshore oil production, or active oil well)
		Vents	89%	ND	99%	ND	ND	ND	ND	ND	
		Flares	3%	ND	-	ND	ND	ND	ND	ND	
Offshore Oil Production	All	Leaks	33%	ND	-	ND	ND	ND	ND	ND	Apply percentages to applicable EF (EF based on offshore gas production)
		Vents	0%	ND	99%	ND	ND	ND	ND	ND	
		Flare	67%	ND	1%	ND	ND	ND	ND	ND	
Oil Sands Mining and Ore Processing	All	Leaks[a]	2.3%	ND	0.3%	ND	20.9%	ND	3%	ND	Apply percentages to applicable EF (EF based on crude bitumen production from surface mining)
		Tailings Ponds	91.2%	ND	46.9%	ND	45.9%	ND	-	ND	
		Exposed Mine Surface	6.3%	ND	30.4%	ND	33.2%	ND	-	ND	
		Vents	0%	ND	3%	ND	-	ND	-	ND	
		Flare	0.3%	ND	19.4%	ND	0.1%	ND	97%	ND	
	All	Leaks	8%	ND	0%	ND	39%	ND	17%	ND	

Oil Sands Upgrading		Vents	82%	ND	82%	ND	53%	ND	-	ND	Apply percentages to applicable EF (EF based on synthetic crude oil production)
		Flare	11%	ND	18%	ND	8%	ND	83%	ND	
a. Within leaks for Oil Sands Mining and Ore Processing, 91% of emissions are from tailing ponds, and 6% of emissions are from exposed mine surface.											

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TABLE 4A.3 DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR OIL REFINING, 1.B.2.A.III..4											
Category	**Sub-category**	**Emission source**	**CH_4**		**CO_2**		**NMVOC**		**N_2O**		**Units of measure**
			Value	**Uncertainty (% of value)**	**Value**	**Uncertainty (% of Value)**	**Value**	**Uncertainty (% of value)**	**Value**	**Uncertainty (% of value)**	
Oil Refining	All	Leaks[a]	99%	ND	55%	ND	ND	ND	ND	ND	Apply percentages to applicable EF (EF based on thousand cubic meters oil refined)
		Flares	1%	ND	45%	ND	ND	ND	ND	ND	
a. Within leaks, for methane, 67% of emissions are from storage of oil products, and 18% of emissions are from storage of crude oil at refineries.											

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TABLE 4A.4
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS PRODUCTION, 1.B.2.B.III.2

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Onshore production	Most activities occurring with higher- emitting technologies and practices	Leaks	11%	ND	-	ND					Apply percentages to applicable EF (EF based on either gas production or gas wells)
		Vents	89%	ND	3%	ND					
		Flare	-	ND	97%	ND					
Onshore Production	Most activities occurring with lower-emitting technologies and practices	Leaks	10%	ND	0%	ND					Apply percentages to applicable EF (EF based on either gas production or gas wells)
		Vents	90%	ND	1%	ND					
		Flare	-	ND	98%	ND					
Offshore Gas production	All	Leaks	33%	ND	-	ND					Apply percentages to EF (EF based on offshore gas production)
		Vents	0%	ND	99%	ND					
		Flare	67%	ND	1%	ND					

TABLE 4A.5
DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS PROCESSING SEGMENT, 1.B.2.B.III.3.

Category	Sub-category	Emission source	CH_4		CO_2		NMVOC		N_2O		Units of measure
			Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Gas Processing	Without LDAR, limited use of dry seal compressors	Leaks	45%	ND	51%	ND					Apply percentages to applicable EF (EF based on either gas processed or gas produced)
		Vents	55%	ND	49%	ND					
		Flare	0%	ND	-	ND					
Gas Processing	With LDAR, around 50% or more of centrifugal compressors are dry seal	Leaks	4%	ND	56%	ND					Apply percentages to applicable EF (EF based on either gas processed or gas produced)
		Vents	91%	ND	44%	ND					
		Flare	5%	ND	-	ND					
Gas processing	Acid Gas Removal	Vents	100%	ND	100%	ND					Apply percentages to applicable EF (EF based on either gas processed or gas produced)

TABLE 4A.6 DISAGGREGATION OF TIER 1 EMISSION FACTORS FOR GAS TRANSMISSION SEGMENT, 1.B.2.B.III.4.											
Category	**Sub-category**	**Emission source**	**CH_4**		**CO_2**		**NMVOC**		**N_2O**		**Units of measure**
			Value	**Uncertainty (% of value)**	**Value**	**Uncertainty (% of Value)**	**Value**	**Uncertainty (% of value)**	**Value**	**Uncertainty (% of value)**	
Gas Transmission	Most activities occurring with higher-emitting technologies and practices	Leaks	39%	ND	43%	ND					Apply percentages to applicable EF (EF based on either gas consumption or kilometer pipeline)
		Vents	61%	ND	57%	ND					
		Flare	-	ND	-	ND					
Gas Transmission	Most activities occurring with lower-emitting technologies and practices	Leaks	7%	ND	12%	ND					Apply percentages to applicable EF (EF based on either gas consumption or kilometer pipeline)
		Vents	93%	ND	88%	ND					
		Flare	-	ND	-	ND					

2876

Annex 4A.3 Other available data on emission factors

NEW

For many emission sources in the oil and gas sector, countries report country-specific emission factors in their national greenhouse gas inventories. While section 4.2 emission factors are intended to be broadly applicable, technologies and practices are changing rapidly in the oil and gas sector and other data sources could be assessed. This annex presents draft preliminary information on available information from national greenhouse gas inventory reports, which may be of interest where practices and technologies for the factors below are more relevant than those presented in section 4.2. In addition, for certain segments, the annex presents emission factors at a greater level of disaggregation than section 4.2 (e.g. distribution sector emissions by pipeline material).

1. Exploration

Several countries reported country-specific data for exploration.

TABLE 4A.7

		IEF kg/well drilled		Information
		CH_4	CO_2	
Oil wells	New Zealand	0.00043	0.028	Unless noted otherwise, CO2 and CH4 emissions from sources within this category have been calculated using the IPCC Tier 2 approach
Oil and gas wells	Australia	4,297	54,991	Different methods used for oil versus gas, but they're combined in CRF. includes oil and gas, Uses some U.S. data, but has newer data on drilling, and an APPEA factor for onshore and offshore testing. Includes completions and workovers
Non HF gas	US	67.1	7.0	Includes drilling and completions. From EPA/GRI 1996
HF gas no controls	US	3,944.8	12,482.2	Includes drilling (from EPA/GRI 1996) and completions (from GHGRP)
HF gas controls	US	36,876.8	12,482.2	Includes drilling (from EPA/GRI 1996) and completions (from GHGRP)

2. Oil Refining and storage

Several countries reported country-specific data for refining. Many Parties reported different IEF between 1990's and more recent years, but unlike in other segments, there appeared to be no clear trend. To provide comparison with the IPCC 2006 default values, EFs were converted to units of kg per 10^3m3 oil refined, based on oil refining data reported in the country's Common Reporting Format (CRF). The tables below compare emission factors developed from 2015 data reported in the 2017 CRF tables and National Inventory Reports (NIRs), and 1990 data reported in the 2017 CRF tables and NIRs.

TABLE 4A.8

	data points		Mean (average of national EFs)		Weighted mean (by gas consumption)		min		max	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	13	6	44	43,735	29	7,513	1	61	203	173,418
2015	13	7	2,962	81,295	27	10,210	0	2,889	37,822	320,453
IPCC		1			22		2.6		41	

Comparing 1990 and 2015 years, removing outliers of 208170% and 99900%, on average (by country) EF decreased 15% for kg CH_4/10^6m3 and increased 49% for kg CO2/10^6m3. The weighted mean shows a decrease of around 6% from new to old for CH_4, and a 36% increase for CO2. The mean IEFs from averaging national EFs are significantly higher than the 2006 IPCC default values.

TABLE 4A.9 **BACK GROUND INFORMATION** (Unit: Kg/10^3m3 oil refined)				
	CH_4		**CO_2**	
	1990(1995)	2015(2016)	1990	2015(2016)
Germany	26.72	0.558	-	512.07
UK	1.41	0.08	-	-
Norway	0.20	0.30	-	-
US	0.03	0.04	4.06	3.12

3. Oil transport

Several countries reported using country-specific parameters for oil transport.

TABLE 4A.10		
	CH4	
	1990	**2015**
Germany	5.75	
UK	13.28	9.77
Norway	79	48.26
US	5.10 (on-shore) 13.21 (off-shore)	
Denmark	10(on-shore) 50(off-shore)	
IPCC	5.4	

4. Gas exploration

Few Annex I Parties reports emission (including leakage, venting and flaring) separately and use country-specific EF data.

TABLE 4A.11 (Unit: Kg/10^3 m3)					
Segment	**category**	**UK (average of 2000-2015)**		**Denmark (keep consistent during 1990-2015)**	
		CH_4	CO_2	CH_4	CO_2
Gas exploration	all	30.15	1876	10.56	2820

5. Gas production

Several countries reported emission from gas production using country-specific EFs. The table following provides the summary of the IEFs from these countries in their 2017 submissions.

TABLE 4A.12 (Unit: Kg/10^3 gas produced)								
	data points		**Mean (average of national EFs)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	6	5	1.20	0.12	0.38	0.0005	2.04	0.40
2015	6	5	1.10	0.09	0.12	0.000495	2.44	0.23

No distinction	3	3	2.57	0.09	1.34	0.048	4.08	0.13
IPCC					0.381		2.3	

TABLE 4A.13
BACKGROUND DATA

(Unit: kg /10^3 gas produced)

1990			**2015**			**no distinction**		
	CH_4	CO_2		CH_4	CO_2		CH_4	CO_2
Australia	2.04	0.40	Australia	1.38	0.23	Belarus	4.08	0.13
Canada	1.31	0.04	Canada	0.49	0.01	Slovakia	2.3	0.082
Czech Republic	1.27	0.000505	Czech Republic	1.24	0.000495	Hungary	1.34	0.048
Germany	0.38	0.095	Germany	0.12	0.105			
Iceland	0.46		Iceland	2.44				
Italy	1.736	0.082	Italy	0.906	0.082			

6. Gas Processing

Several countries reported country-specific data for processing. Many countries reported different IEF between 1990's and more recent years, with most showing lower emissions in recent years. To provide comparison with the IPCC 2006 default values, EFs were converted to units of kg per 10^6m3 gas production, based on gas production data reported in the Party's CRF. The tables below compare emission factors developed from 2015 data reported in the 2017 CRF tables and NIRs, and 1990 data reported in the 2017 CRF tables and NIRs, with certain exceptions.

TABLE 4A.14

(Unit: Kg/10^6m3 gas processed)

	data points		**Mean (average of national EFs)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	7	4	433	104	76.4	7.40	941	264
2015	7	4	292	119	9.78	40	919	248
IPCC			1030	320				

TABLE 4A.15
BACKGROUND DATA

(Unit: kg /10^6 m3 gas processed)

1990			**2015**		
	CH_4	**CO_2**		**CH_4**	**CO_2**
Australia	284.75	51.52	Australia	318.92	54.27
Canada	173.00	7.40	Canada	57.00	40.00
France	76.41	-	Czech Republic	9.78	
Germany	350	92	Germany	44	134
Hungary	941.00	264.00	Iceland	919.00	248.00
Italy	773		Italy	406	
UK	461	-		58	

TABLE 4A.16 (Unit: Kg/10^6m3 gas feed)										
	data points		**Mean (average of national EFs)**		**Weighted mean (by gas consumption)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	5	5	623	30,719	1,276	41,283	218	9	1,621	92,000
2015	5	5	219	34,050	443	23,043	44	46	546	134,400
IPCC		1	590(?)	43,166	-	-	152	3,320	1,180	99,128

Comparing 1990 and 2015 years, on average (by country) EF decreased 65% for kg CH_4/10^6m3 and increased 10% for kg CO2/10^6m3. The weighted mean shows a decrease of around 65% from 1990 to 2015 for CH_4, and a 44% decrease for CO2. The mean IEFs from averaging national EFs are higher than the 2006 IPCC default values. For the weighted mean approach, the 1990 IEF are higher than the IPCC defaults and the 2015 IEF are lower.

TABLE 4A.17 **CO_2 EFS GAS PRODUCTION WITH AND WITHOUT ACID GAS REMOVAL** (Unit: Kg/10^6m3 gas production)										
	data points		**Mean (average of national EFs)**		**Weighted mean (by gas consumption)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
No AGR		2		55		51		46		64
AGR		4		53,327		29,225		6,617		134,400
IPCC-no AGR		4		3,368				3,012		4,128
IPCC-AGR				58,333				40,000		95,000

7. Gas Transmission and Storage

Several countries reported country-specific data for transmission and storage. Many Parties reported different IEF between 1990's and more recent years, with most showing lower emissions in recent years. Seven countries provided data on length of transmission pipeline. The tables below compare emission factors developed from 2015 data reported in the 2017 CRF tables and NIRs, and 1990 data reported in the 2017 CRF tables and NIRs.

TABLE 4A.18 (Unit: kg/km)										
	data points		**Mean (average of national IEFs)**		**Weighted mean (by pipeline length)**		**min**		**Max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	7	6	398.1	12.9	977.3	26.8	59.3	0.3	1,167.9	33.7
2015	7	6	118.0	3.3	192.2	5.6	47.9	0.3	214.0	7.3
no distinction	1	1	7.7	0.2						
2006 IPCC T1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Comparing 1990 and 2015 years, on average (by country) EF decreased by 35% for kg/km CH_4 and 32% for kg/km CO2. The weighted mean shows a decrease of around 45% from new to old. There is no existing T1 value on a pipeline length basis for transmission and storage for comparison.

TABLE 4A.19 (Unit: Kg/10^6m3)										
	data points		**Mean (average of national EFs)**		**Weighted mean (by gas consumption)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	9	7	759	16	3,355	88	69	1	4,315	114
2015	9	7	357	9	1,397	40	53	1	1,745	50
no distinction										
IPCC	4	4	773	5			135	4	1,898	10

Comparing 1990 and 2015 years, on average (by country) EF decreased by 27% for kg CH_4/10^6m3 and 3% for kg CO2/10^6m3. The weighted mean shows a decrease of around 55% from 2015 to 1990. The mean IEFs from averaging national EFs are comparable to the 2006 IPCC default values. For the weighted mean approach, the 1990 IEF is higher than the IPCC defaults and the 2015 IEF is higher than the average, but lower than the highest default value.

TABLE 4A.20 TRANSMISSION										
	data points		**Mean (average of national EFs)**		**Weighted mean (by gas consumption)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	5	2	986	50			74	12	3359	87
2015	5	2	546	23			116	8	1686	39
no distinction										
IPCC			740	5			110	4	1,840	9

Comparing 1990 and 2015 years, on average EF decreased by 37% for kg/10^6m3 CH_4 and 53% for kg/10^6m3CO2. The IPCC average EF is between the old and new EFs for CH_4, and is much lower than the old and new EF for CO2.

8. Gas Distribution

Several countries reported country-specific data for distribution. Many countries reported different IEF between 1990's and more recent years, with most showing lower emissions in recent years. The most commonly reported unit was kg/PJ. To provide comparison with the IPCC 2006 default values, gas consumption data reported was converted to 10^6m3. Several countries provided data on length of distribution pipeline. The tables below compare emission factors developed from 2015 data reported in the 2017 CRF tables and NIRs, and 1990 data reported in the 2017 CRF tables and NIRs, with certain exceptions.

TABLE 4A.21 (Unit: kg/km)										
	data points		**Mean (average of national IEFs)**		**Weighted mean (by pipeline length)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	7	6	398.1	12.9	977.3	26.8	59.3	0.3	1,167.9	33.7
2015	7	6	118.0	3.3	192.2	5.6	47.9	0.3	214.0	7.3
no distinction	1	1	7.7	0.2						
2006 IPCC T1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Comparing 1990 and 2015 years, on average (by country) EF decreased by 47% for kg/km CH_4 and 53% for kg/km CO2. The weighted mean shows a decrease of around 80% from new to old. There is no existing T1 value on a pipeline length basis for distribution for comparison.

TABLE 4A.22

(Unit: Kg/10^6m3)

	data points		**Mean (average of national EFs)**		**Weighted mean (by gas consumption)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	15	12	139,767	7,060	4,787	121	593	15	718,720	74,302
2015	15	12	133,944	7,337	1,208	32	302	0	723,280	85,065
no distinction	2	1	38	2			10	-	67	
IPCC	3	3	1,567	81			1,100	51	2,500	140

Comparing 1990 and 2015 years, on average (by country) EF decreased by 41% for kg CH_4/10^6m3 and 42% for kg CO2/10^6m3. The weighted mean shows a decrease of around 75% from 1990 to 2015. The mean IEFs from averaging national EFs are significantly higher than the 2006 IPCC default values. For the weighted mean approach, the 1990 IEF are higher than the IPCC defaults and the 2015 IEF are lower.

TABLE 4A.23

	data points		**Mean (average of national EFs)**		**Weighted mean (by gas consumption)**		**min**		**max**	
	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2	CH_4	CO_2
1990	12	10	10,155	181	4,787	121	593	-	31,472	1,121
2015	12	10	3,908	76	1,208	32	302	0	18,000	529
no distinction	5	3	392,356	29,067			10	2	723,280	85,065
IPCC	3	3	1,567	81			1,100	51	2,500	140

Comparing 1990 and 2015 years, on average EF decreased by 52% for kg/10^6m3 CH_4 and 60% for kg/10^6m3CO2. The weighted mean shows a decrease of around 75% from new to old. The mean IEFs from averaging national EFs are higher than the 2006 IPCC default values, except for CO2 from new distribution systems. For the weighted mean approach, the "old" IEF are higher than the IPCC defaults and the "new" IEF are lower.

Additional disaggregated data available for distribution.

TABLE 4A.24

Values for methane in t/km	**plastic**	**steel**	**Grey cast**
Germany-Low pressure (<100 mbar)	0.018	0.02	1.48
Germany-Mid pressure (100 mbar -1000 mbar)	0.035	0.025	2.96
Germany-High pressure (>1000 mbar)	0.011	0.06	N.A.

U.S. mains	0.119 (1990's), 0.018 (2010's)	Unprotected steel-1.319 (1990's), 0.535 (2010's). Protected steel—0.037 (1990's), 0.060 (2010's)	2.86 (1990's), 0.72 (2010's)

TABLE 4A.25			
Values for carbon dioxide in t/km	**plastic**	**steel**	**Grey cast**
Germany-Low pressure (<100 mbar)	0.54 * 10^-3	0.6 * 10^-3	44.4 * 10^-3
Germany-Mid pressure (100 mbar -1000 mbar)	1.05 * 10^-3	7.5 * 10^-3	88.8 * 10^-3
Germany-High pressure (>1000 mbar)	0.33 * 10^-3	1.8 * 10^-3	N.A.
U.S. mains	0.002 (1990's), 0.002 (2010's)	Unprotected steel-0.104 (1990's), 0.015 (2010's). Protected steel—0.002 (1990's), 0.003 (2010's)	0.239 (1990's), 0.019 (2010's)
U.S. service			

Annex 4A.4 Definition of terminologies used in section 4.2

The location of this contents may be changed in the second order draft.

(letter refers to source)

abandon: the proper plugging and abandoning of a well in compliance with applicable regulations and the cleaning up of the well site to the satisfaction of the operator and the regulatory body with jurisdiction (d) to cease efforts to find or produce from a well or field or to plug a well completion and salvage material and equipment. (e) the plugging of wells, removal of equipment, production tanks and associated installations, and surface remediation.

abandoned well: a well no-longer in production or being actively explored; such wells may be unplugged or plugged; wells plugged according to regulations and abandoned are also known as decommissioned wells while wells that are not regularly inspected or repaired and remain unplugged are abandoned but not decommissioned.

acid gas: gas that, when mixed with water, forms an acidic solution (e.g. hydrogen sulfide (H_2S) and carbon dioxide (CO_2) - both obtained after sweeting sour gas).

API: the American Petroleum Institute, the primary trade association representing the oil and natural gas industry in the United Status.

API gravity: gravity scale developed by the American Petroleum Institute that expresses the relative density of petroleum liquids as API degrees; most values fall between 10 and 70 degrees API gravity, and the lower the API gravity, the higher the density of a hydrocarbon.

asphalt: solid or nearly solid bitumen with impurities (nitrogen, oxygen, sulphur) that can melt upon heating; forms when light components or volatiles of petroleum have been removed or evaporated.

associated gas: gas produced along with oil.

bitumen: typically solid hydrocarbon with high density (API < 10 degrees; e.g. asphalt).

blow-down: condensate and gas produced simultaneously at the outset of production. (e) to vent gas from a well or production system (e.g. when starting well work on a well that has been shut for a period of time)

blow out: when well pressure exceeds the wellhead valves' ability to control it and oil and gas are released at the surface; uncontrolled, possibly catastrophic, flow of reservoir fluids into wellbore that may consist of salt water, oil, gas, or a mixture thereof.

bore hole: the hole drilled by the drill bit; the wellbore including open hole or uncased portion of the well.

cap rock: relatively impermeable rock (e.g. shale, anhydrite, salt) that forms a seal above a reservoir rock and prevents fluids from migrating out of the reservoir.

casing: pipe lowered into an open hole and cemented in place to prevent collapse of the borehole and to protect freshwater, isolate zones of lost returns, or isolate formations with different pressure gradients.

carbon capture and storage (CCS): the process of trapping carbon dioxide (CO_2) and storing it in a way that it is unable to enter the atmosphere.

CO_2 injection: an enhanced oil recovery (EOR) method whereby CO_2 gas is injected into a reservoir to reduce viscosity and increase production.

carbon intensity: average emission rate of carbon dioxide (CO_2) from a source per unit of activity (e.g. g CO_2 per MJ of energy produced).

casing: cement pipe down a well meant to prevent fluids from escaping and/or the borehole from collapsing.

casing head: the adapter between the first casing and the wellhead.

chemical flooding: a type of enhanced oil recovery (EOR) that utilizes alkaline or micellar-polymer flooding.

coal bed methane: natural gas (methane/CH_4, mainly) generated during coal formation and absorbed in coal.

cold production: non-thermal primary methods of heavy oil production.

completion: the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well.

compressor: a device that raises pressure of air or natural gas so the gas can flow into pipelines or other facilities.

compressor station or plant: facility with many compressors, auxiliary treatment equipment, and pipeline installations to pump natural gas under pressure over long distances.

condensate: gaseous hydrocarbons under reservoir conditions (temperature, pressure) that become liquid at the surface; includes a mixture of pentanes and higher hydrocarbons.

conservation efficiency (CE): a factor that expresses the amount of produced gas and vapor captured and used for fuel, produced into gas gathering systems, or re-injected (1.0 = all gas is conserved, utilized or re-injected; 0 = gas is vented or flared).

conventional oil: oil produced from a conventional reservoir

conventional reservoir: a reservoir where buoyant forces maintain hydrocarbons beneath a sealing cap stone and whose properties usually allow oil or natural gas to flow readily into well bores; this is distinct from shale or unconventional reservoirs, where gas may be distributed throughout the reservoir at basin scale and where additional buoyant forces or the influence of a water column is not significant.

crude oil: liquid petroleum as it arises from the ground, distinguished from refined oils that are manufactured from it.

decommissioned well: an abandoned well no longer in production that has been isolated according to current regulatory requirements and best practices (e.g. cut-off, sealed, and possibly buried); such wells may still deteriorate over time, and may require inspection and repair when necessary, though the regulatory requirements to do so may vary considerably.

deep-cut extraction plant: gas processing plants located on gas transmission systems which are used to recover residual ethane and heavier hydrocarbons present in the natural gas.

directional drilling: the intentional deviation of a well bore from the path it would have naturally taken by using specialized, steerable drilling equipment; commonly used in shale reservoirs to allow producers to place the borehole in contact with the most productive reservoir rock.

directional well: a well bore that uses special tools and/or techniques to make sure that its path hits a particular target that is usually located away from (as opposed to directly under) the surface location of the well.

distribution: for oil systems, the segment of the system that includes the transport and distribution of refined products, including bulk and retail facilities; for natural gas systems, this segment includes high-pressure gas pipelines that transfer natural gas to the “city gate” and then to end users through underground main and service pipelines, distribution of town gas, and short term surface storage.

dry hole: an exploratory well where no hydrocarbons are found; a non-productive well.

dry gas: natural gas that does not require any hydrocarbon dew-point control to meet sales gas specifications (may require treating to meet water and acid gas (H_2S and CO_2) content); usually produced from shallow (< 1000 m deep) gas wells;natural gas composed primarily of methane (CH_4) with minor amounts of ethane, propane and butane and little or no heavier hydrocarbons (e.g. those in the gasoline range).

emission control device: a device used to regulate the amount of gasses or air pollutants emitted from a source.

enhanced coal bed methane (ECBM): increased methane (CH_4) recovery produced by the injection of CO_2 into coal seams.

enhanced gas recovery (EGR): increased recovery of natural gas by injection of inert gases (e.g. N_2, CO_2) to increase well pressure.

enhanced oil recovery (EOR): recovery of oil from a reservoir by means other than using the natural reservoir pressure; can begin after a secondary recovery process or at any time during the productive life of an oil reservoir;an oil recovery enhancement method that uses sophisticated techniques that alter original the properties of oil with purpose of restoring formation pressure and improving oil displacement or fluid flow in reservoir; there are three major types: chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (CO_2 injection or hydrocarbon injection) and thermal recovery (steam flood or *in situ* combustion).

exploration: the part of oil and natural gas systems that includes well drilling, stem testing, and well completion; the process of trying to find accumulations of oil and natural gas under the surface of the earth (includes well drilling, drill stem testing, and well completions); drilling carried out to determine if hydrocarbons are present in a particular area or geologic structure; the initial phase of petroleum operations that includes generation of a prospect or play or both and drilling of an exploration well; appraisal, development and production phases follow successful exploration.

exploration well: a well drilled in an unproven area in an attempt to locate oil and natural gas.

flaring: emissions from flaring of natural gas and waste gas/vapour streams at oil and natural gas facilities; the burning of waste natural gas and hydrocarbon liquids by flares or incinerators as a disposal option rather than for the production of useful heat or energy.

flaring destruction efficiency (FE): the fraction of gas that leaves the flare partially or fully burned.

flow-back: gas, crude oil and water (including water injected during hydraulic fracturing) that are produced from a well until the flow of gas and liquid hydrocarbon is steady; the process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.

fuel: any substance burned as a source of energy such as heat or electricity.

fuel combustion: the intentional oxidation of materials within an apparatus that is designed to provide heat or mechanical work to a process, or for use away from the apparatus.

fugitive emissions (oil and natural gas): the intentional or unintentional release of greenhouse gases that occur during the extraction, processing and delivery of fossil fuels to the point of final use; this excludes greenhouse gas emissions from fuel combustion; emissions that are not emitted through an intentional release through stack or vent; this can include leaks from pipelines and pneumatic devices.

gas appliances: end of pipe equipment such as home heating equipment, water heaters, saunas, stoves, and barbecues that use natural gas.

gathering system: the network of flow lines and process facilities that transport and control the flow of oil or gas from wells to a main storage facility, processing plant, or shipping point (includes pumps, headers, separators, emulsion treaters, tanks, regulators, compressors, dehydrators, valves).

gas injection: the process of pumping associated gas into a reservoir for conservation or to maintain reservoir pressure.

gas-to-oil ratio (GOR): volume of gas at atmospheric pressure produced per unit of oil produced.

gas well: a well with natural gas as the primary product, but on that can also produce condensate (natural gas liquids like propane and butane) and water.

heater treater: a three-phase separator that separates crude oil, water, and associated gas from the output of a well.

heavy crude: a low API/high density hydrocarbon.

horizontal drilling: a subset of directional drilling where the departure of well bore from vertical exceeds ~ 80 degrees.

hydraulic fracturing: a method of enhanced oil or gas recovery by which a geologic formation is broken down by pumping down fluids at very high pressures; the purpose is to increase production rates from a reservoir.

hydrocarbon: strictly defined as molecules containing only hydrogen and carbon, but the term is used more broadly to include any molecules in petroleum which also contain S, N, or O; hydrocarbons may exist as a solid, liquid, or gas and are generally used to refer to oil, gas, and condensate.

hydrogen sulfide (H_2S): a poisonous gas present in some subsurface formations.

injection well: a well used to pump water or gas into a reservoir.

***in situ* combustion:** a method of thermal recovery where fire, generated inside a reservoir by injecting oxygen/air, burns heavy hydrocarbons and vaporizes lighter hydrocarbons, pushing out hot combustion gases, steam and oil water while also reducing oil viscosity.

light crude: a high API/low density crude (API > 40 degrees).

light hydrocarbons: low molecular weight hydrocarbons (e.g. methane, ethane, butane)

liquid hydrocarbons: light liquid compounds extracted from gas flow stream (e.g. propane, butane, pentane)

liquid petroleum gas (LPG): heating propane

liquids unloading: see unloading

liquefied natural gas (LNG): oilfield or naturally occurring gas (mostly methane and ethane), liquefied at cryogenic temperatures for transportation.

liquified petroleum gas (LPG): a light hydrocarbon that is gaseous at atmospheric temperature and pressure and which is held in a liquid state (by pressure) in order to ease transport and handling; consists of either propane, butane, or mixtures of the two.

lubricants: hydrocarbons produced from distillate or residue that are mainly used to reduce friction between bearing surfaces; includes all finished grades of lubricating oil, from spindle oil to cylinder oil, and those used in greases, including motor oils and all grades of lubricating oil base stocks.

mboe: million barrels of oil equivalent

meter and regulator stations: points of transfer where pipeline companies measure gas quality and volumetric flow, and reduce the pressure of pipeline gas to feed natural gas distribution systems

methane (CH_4): the lightest and most abundant hydrocarbon gas and main component of natural gas.

miscible displacement: a type of enhanced oil recovery (EOR) that uses CO_2 injection or hydrocarbon injection.

natural gas: a gas that occurs naturally and often in association with crude petroleum; a mixture of hydrocarbon gases that is highly compressible and expansible (consists primarily of methane, but also ethane, propane, butane, and pentane; impurities such as CO_2, He, N, and H_2S may also be present).

natural gas liquids (NGLs): constituents of natural gas whose products include polyethelyne, polypropylene, and liquified petroleum gas (LPG); liquid hydrocarbons associated with natural gas.

non-methane volatile organic compounds (NMVOC): a class of emissions which includes a wide range of specific organic chemical substances which are precursors for the formation of ozone, a greenhouse gas and air pollutant, in the troposphere (lower atmosphere).

off-gas: the exhaust gas from a chemical process (combustion or non-combustion). The off gas may be vented to the atmosphere, burned for energy recovery or flared (without energy recovery), or used as a feedstock for another chemical process. Secondary products may also be recovered from the off gas; streams from oil and gas treatment units (e.g. still-column off-gas from glycol dehydrators, emulsion treater overheads and stabilizer overheads)

oil: a mixture of liquid hydrocarbons of different molecular weights.

oil sand: a porous sand layer or sand body filled with oil; a heavy oil considered to be a mixture of sand, clay, water and bitumen. In the context of Canadian oil sands, the API is < 10 degrees, and *in situ* recovery and mining methods are used to extract the resource.

oil shale: oil obtained by artificial maturation of oil shale using controlled heating (pyrolysis) of kerogen to release the oil.

oil well: a producing well that has oil as its primary product; such a well always produces some associated gas and frequently water as well.

permeability: the property of a geologic formation that quantifies the flow of fluid through pore spaces and into the well bore.

petroleum: a generic term for hydrocarbons that includes crude oil, natural gas liquids, natural gas, and their products; a complex mixture of naturally occurring hydrocarbon compounds found in rock which range from solid to gas, but usually refers to liquid crude oil. Impurities such as sulfur, oxygen and nitrogen are common and there is considerable variation in color, gravity, odor, sulfur content and viscosity in petroleum from different areas.

pipeline: a tube or system of tubes used to transport crude oil and natural gas from the field or gathering system to the refinery.

pipeline capacity: the volume of gas or oil needed to maintain a full pipeline expressed in barrels per foot (bbl/ft)

pipeline gas: gas that is sufficiently dry that it will not precipitate out natural gas liquids (NGLs) at pressure and that has enough pressure to enter high-pressure gas pipelines.

pipeline oil: oil whose water, sediment and emulsion content is low enough for pipeline shipment.

plug and abandon: to prepare a well bore to be closed permanently (shut in and permanently isolated) after it is determined that there are insufficient hydrocarbons to complete an exploratory well or after production operations have drained a reservoir; regulatory requirements usually dictate how this occurs (most require cement plugs to be placed in the well born with inflow or integrity tests made at each stage to confirm hydraulic isolation).

pore gas: interstitial gas stored in the pore space of reservoir rock.

porosity: the percent of void in a porous rock compared to solid.

pneumatic contollers/devices: chemical injection pumps, starter motors on compressor engines, instrument control loops, liquid level controllers, pressure regulators, and valve controllers that are powered by pressurized natural gas.

primary fuels: fuels extracted directly from natural resources; examples include crude oil, natural gas, coals, etc.

processing: the segment of natural gas systems where natural gas liquids (NGLs) and other constituents (e.g. sulfur) from raw gas are removed to prepare "pipeline quality" gas.

production: well servicing, oil sand/shale oil mining, and transport of untreated production (well effluent, emulsion, oil shale and oilseeds) to extraction/treating facilities; the delivery of gas from the well via gathering pipelines; the process of recovering accumulations of oil and natural gas trapped under the surface of the earth.

reciprocating compressor: a compressors that use pistons driven by a crankshaft to deliver gases at high pressure.

refining: the segment of oil systems where refineries process crude oils, natural gas liquids (NGLs) and synthetic crude oils into final products (e.g. primary fuels and lubricants).

reservoir: an underground formation where oil and gas has accumulated; consists of porous rock that holds oil and gas and a cap rock that prevents its escape;a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids; sedimentary rocks are the most common because they are more porous than most igneous and metamorphic rock.

secondary recovery: the recovery of oil or gas by artificially maintaining or enhancing reservoir pressure by injection gas, water or other substances into the reservoir rock; the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through wells located in rock that has fluid communication with production wells; the purpose is to maintain reservoir pressure and displace hydrocarbons towards the wellborn.

shale: a fine grained impervious sedimentary rock of clays and other minerals (including high percentage of quartz).

shale gas: natural gas produced from low-permeability deep shale formations; shale that is thermally mature enough and has sufficient natural gas content to produce economic quantities of natural gas.

shale oil: oil obtained by artificial maturation of oil shale that uses controlled heating (pyrolosis) of kerogen to release the shale oil.

shut in well: a well capable of producing but is no currently due to numerous reasons.

sour: oil or gas contaminated with sulfur or sulfur compounds (especially hydrogen sulfide).

sour gas: natural gas that must be treated to satisfy sales gas restrictions on H2S content; gas containing H_2S or CO_2; gases can be acidic alone or when associated with water.

sour crude: crude oil with with high sulfur content.

storage: natural gas kept temporarily on long-term in above ground tanks or below-ground formations. crude oils or refined products stored in above ground tanks.

sweet: lacking appreciable amounts of sulfur or sulfur compounds

sweet crude oil: oil with small amounts of H_2S and/or CO_2.

sweet gas: natural gas that does not contain any appreciable amount of H_2S (i.e. does not require treatment to meet requirements for H_2S content)

sweetening: the process that removes hydrogen sulfide or carbon dioxide from a gas stream.

synthetic crude oils: output from a bitumen or extra heavy oil upgrader, usually in connection with oil sand production or output from oil shale pyrolysis (i.e. shale oil).

synthetic natural gas (SNG): gas obtained from heating coal or refining heavy hydrocarbons.

tar sand: a sand body containing heavy hydrocarbon residues (e.g. tar or asphalt) or degraded oil that has lost its volatile components; hydrocarbons can be liberated by heating and other processes at typically high cost. Also known as oil sands.

thermal recovery: a type of enhanced oil recovery (EOR) that uses stream flood or *in situ* combustion; a process that introduces heat into a reservoir to produce viscous, thick oils (i.e. API < 20 degrees; oils that cannot flow unless heated to reduce viscosity and allow flow toward producing well); encompasses hot fluid injection (steam injection, stream flood or cyclic steam injection), hot water flooding, and *in situ* combustion processes

tight gas: an alternative name for shale gas, referring to the low permeability of deep shale formations; gas produced from a relatively impermeable reservoir rock that is generally difficult to produce without stimulation operations, but generally used for reservoirs other than shales

transmission: pipeline transportation of pipeline quality gas

transmission compressor station: stations placed within natural gas transmission systems to help maintain the pressure of the gas within a pipeline as it flows from the natural gas field to market.

transport: the segment of oil systems that is related to the transport of marketable crude (conventional, heavy, and synthetic crude oil and bitumen) to upgraders and refineries by pipeline, marine tankers, tank trucks, and rail cars.

unconventional resource: a term for oil and natural gas that is produced by means that do not meet the criteria for conventional production (these criteria are a complex function of resource characteristics, the available exploration and production technologies, the economic environment and the scale, frequency and duration of production from the resource); presently, used in reference to oil and gas resources whose porosity permeability fluid trapping mechanism or other characteristics differ from conventional sandstone and carbonate reservoirs (e.g. coal bed methane, gas hydrates, shale gas, fractured reservoirs, tight gas, oil sands)

underground gas storage: gas that is being stored in salt domes, salt layers, or depleted oil and gas fields

unload: to initiate flow from a reservoir by removing the column of kill fluid from the well bore (methods include circulation of lower density fluid, nitrogen living and swabbing; method used will depend on completion design and reservoir characteristics).

upgrader: a refinery unit that improves or upgrades heavy oil to produce higher-quality hydrocarbon liquids or upgraded synthetic crude (may include hydrogen addition processes, carbon rejection processes, or carbon concentration and removal processes).

venting: emissions from venting of associated gas and waste gas/vapor streams and oil and natural gas facilities; this includes all engineered or intentional discharges of waste gas streams and process by-products to the atmosphere, including emergency discharges, and the release may be continuous or intermittent.

water flooding: a secondary oil recovery method where water is injected into aa reservoir formation to displace residual oil into adjacent production wells.

well blow-out: *see blowout.*

well bore: a drilled hole or borehole, including the open hole or uncased portion of the well.

well completion: the insertion of multiple layers of cement and steel casing in a downhole well as it is being drilled in order to prevent los of hydrocarbons and contamination of aquifers near the surface; completion of shale gas wells also includes hydraulic fracturing, insertion of tubing through which produced oil flows, and flowback. Installation of permanent wellhead equipment for oil and gas production is also included.

well head: the system of spools, valves and assorted adapters that provide pressure control of a production well.

well integrity: the zonal isolation of liquids and gases.

well servicing: maintenance procedures performed on oil and gas wells after the have been completed and production has begun; these procedures maintain or enhance well productivity.

well testing: a series of activities and tests designed to understand and characterize the characteristics of underground reservoirs where hydrocarbons are trapped.

wet gas: natural gas containing significant heavier hydrocarbons (propane, butane and other NGLs) and that is < 85% methane.

wet oil: oil containing basic sediment and water

workover: remedial work to the equipment within a well, the well pipework, or relating attempts to increase the rate of flow; repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

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